Pipestone Energy Corp. – Financial and Operating Highlights

($ thousands, except per unit and per share amounts)	Three months ended September 30, 2019	2018	Nine months ended September 30, 2019	2018
Financial				
Sales of liquids and natural gas	**$ 7,808**	$ -	**$ 13,725**	$ 1,569
Cash used in operating activities	**(6,626)**	(361)	**(20,188)**	(378)
Funds flow from (used in) operations [1]	**(2,734)**	(512)	**(13,820)**	100
Per share, basic and diluted [2]	**(0.01)**	(0.01)	**(0.07)**	0.00
Loss	**(1,409)**	(1,349)	**(842)**	(2,519)
Per share, basic and diluted [2]	**(0.01)**	(0.03)	**(0.00)**	(0.05)
Capital expenditures	**29,434**	5,428	**125,737**	49,012
Net acquisitions	**$ 98**	$ 1,098	**214**	1,098
Working capital *(end of period)*			**20,893**	10,332
Bank debt *(end of period)*			**156,983**	52,187
Shareholders' equity *(end of period)*			**382,687**	85,661
Available funding *(end of period)* [3]			**$ 32,655**	$ 16,560
Cash return on invested capital (CROIC) *(%)* [3]	**NMN [7]**	NMN [7]	**NMN [7]**	NMN [7]
Return on capital employed (ROCE) *(%)* [3]	**NMN [7]**	NMN [7]	**NMN [7]**	NMN [7]
Shares outstanding *(end of period)* [2]			**189,627**	52,782
Weighted-average basic shares outstanding [2]	**189,627**	52,782	**187,949**	52,782
Weighted-average diluted shares outstanding [2]	**189,627**	52,782	**187,949**	52,782
Operations				
Production				
Condensate and crude oil *(bbls/d)*	**1,112**	-	**600**	97
Natural gas liquids (NGL) *(bbls/d)*	**139**	-	**82**	-
Natural gas *(Mcf/d)*	**7,298**	-	**4,011**	-
Total *(boe/d)* [4]	**2,467**	-	**1,351**	97
Condensate and crude oil *(% of total production)*	**45**	-	**44**	100
Total liquids *(% of total production)*	**51**	-	**50**	100
Benchmark prices				
Crude oil – WTI *(C$/bbl)*	**$ 74.52**	$ 79.52	**$ 75.82**	$ 83.62
Condensate – Edmonton Condensate *(C$/bbl)*	**68.24**	80.30	**70.21**	83.37
Natural gas – AECO 5A *(C$/GJ)*	**0.96**	1.19	**1.49**	1.43
Average realized prices [5]				
Condensate and crude oil *(per bbl)*	**65.17**	-	**66.36**	59.50
NGL *(per bbl)*	**12.57**	-	**19.43**	-
Natural gas *(per Mcf)*	**1.46**	-	**2.21**	-
Netbacks				
Revenue *(per boe)*	**34.40**	-	**37.21**	59.50
Royalties *(per boe)*	**(1.85)**	-	**(1.95)**	(4.19)
Operating expenses *(per boe)*	**(15.29)**	-	**(15.27)**	(9.80)
Transportation *(per boe)*	**(5.65)**	-	**(7.26)**	-
Operating netback *(per boe)* [3]	**11.61**	-	**12.73**	45.51
Funds flow netback *(per boe)* [3]	**$ (12.04)**	$ -	**$ (37.48)**	$ 3.73

(1) See "Additional subtotal – Funds flow from operations" under "Critical Accounting Judgments, Estimates and Policies".

(2) The number of common shares has been adjusted retrospectively to reflect the 10:1 share consolidation, as well as the 0.5996 exchange ratio, as part of the Corporate Acquisition.

(3) See "Non-GAAP measures".

(4) For a description of the boe conversion ratio, see "Basis of Barrel of Oil Equivalent".

(5) Figures calculated before hedging.

(6) IFRS 16, *Leases*, was adopted on January 1, 2019 using the modified retrospective approach; therefore, comparative information was not restated. See "Critical Accounting Judgments, Estimates and Policies".

(7) NMN – not meaningful number at this time as Pipestone Energy is at a pre-production stage.

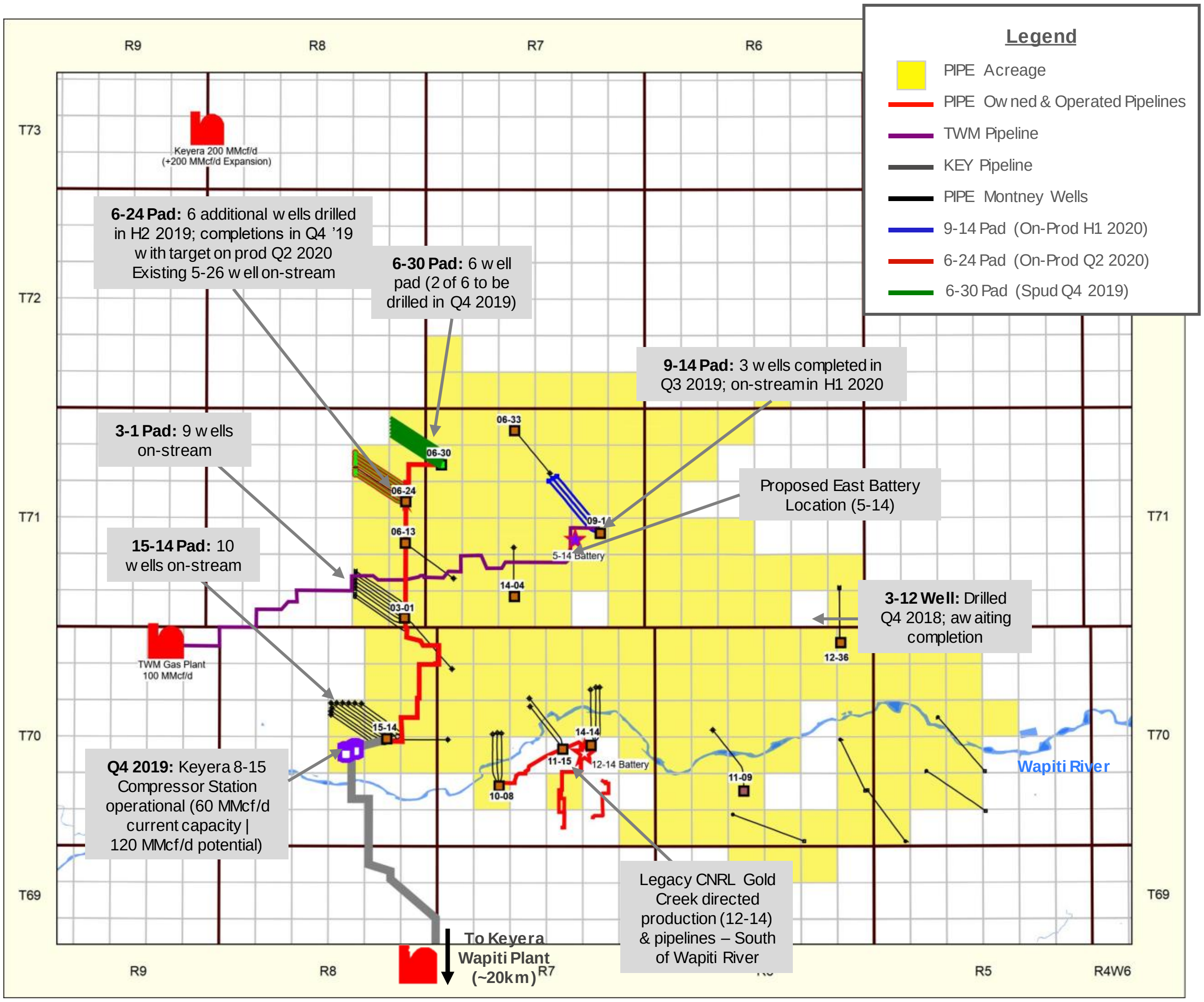
Management’s Discussion and Analysis

This management’s discussion and analysis (MD&A) of operating and financial results of Pipestone Energy Corp. (“Pipestone Energy” or the “Company”) is dated November 13, 2019 and is based on currently available information. It should be read in conjunction with the audited financial statements and accompanying notes for the years ended December 31, 2018 and 2017 and the unaudited condensed interim consolidated financial statements and accompanying notes for the three and nine months ended September 30, 2019 and 2018. Unless otherwise noted, all financial information is presented in thousands of Canadian dollars and is in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB), interpretations of the International Financial Reporting Interpretations Committee (IFRIC), and with Canadian generally accepted accounting principles (GAAP) as applicable to interim financial statements, including International Accounting Standard (IAS) 34, *Interim Financial Reporting*. These documents, along with other statutory filings, are available on SEDAR at www.sedar.com and on the Company’s website at www.pipestonecorp.com.

Refer to the end of the MD&A for commonly used abbreviations.

Readers should read “Forward-Looking Statements” at the end of the MD&A, which explains the basis for and limitations of statements throughout this report that are not historical facts and may be considered “forward-looking statements” under securities regulations.

Description of Pipestone Energy



Pipestone Energy is a liquids and natural gas exploration and production company with its head office located in Calgary, Alberta. The Company is focused on developing its condensate-rich assets in the Pipestone area of the Alberta Montney trend. Pipestone Energy is committed to building long term value for its shareholders and values the partnerships that it is developing within its operating community. Pipestone Energy trades on the TSX Venture Exchange under the symbol PIPE.

Pipestone Energy is early in its development lifecycle. As of September 30, 2019, Pipestone Energy has accumulated 148 net Montney sections in the core Pipestone area and has drilled 39.1 net horizontal Montney wells of which 36.1 have been completed. The Company has also completed building its previously announced in-field gathering system to interconnect with third-party processing infrastructure and egress capacity.

In mid-September 2019 tie-ins were completed to both the Tidewater Pipestone Plant and the Keyera Wapiti Plant allowing Pipestone Energy to start-up production from wells located North of the Wapiti River at the 15-14 and 03-01 pad-sites. The initiation of production from these wells is approximately one-month ahead of the originally planned schedule. Production has continued to ramp-up in October and November as additional wells have been brought on from these pads, as well as one additional well on the 6-24 pad-site, and as the third-party infrastructure run times have improved. Pipestone Energy has also secured the firm transportation required to match its near-term forecasted liquids and natural gas production. The Company believes it is fully funded to achieve a sustainable business capable of generating free cashflow above its maintenance requirements in a flat US$55 per barrel WTI commodity price environment.

On January 4, 2019 the Company completed its reverse takeover of, and amalgamation with, Blackbird Energy Inc. (the “Corporate Acquisition”). Prior to the Corporate Acquisition, Pipestone Energy was a privately held entity, operating under the name Pipestone Oil Corp. (“Predecessor Pipestone”), incorporated under the Business Corporations Act (Alberta) and a wholly-owned subsidiary of Canadian Non-Operated Resources LP (“CNOR LP”), a privately held partnership formed under the laws of Alberta. The comparative figures presented for 2018 and 2017 are that of Predecessor Pipestone.

Third Quarter 2019 Corporate Highlights

- Beginning in mid-September, Pipestone Energy commenced initial start-up production from wells located North of the Wapiti River at both the 15-14 and 03-01 pad-sites. September production from these two pads averaged approximately 4,700 boe per calendar day for the full month (comprised of 46 percent condensate and 53 percent total liquids). The start-up of these pad-sites coincided with the commissioning of the Keyera Corporation ("Keyera") Pipestone Compressor Station and the Tidewater Midstream and Infrastructure Ltd. ("Tidewater") Pipestone Gas Plant. Normal start-up challenges experienced during the commissioning of these third-party processing facilities and the Keyera Wapiti Gas Plant resulted in disruptions and limitations to Pipestone Energy's production and had shrinkage rates in excess of typical plant operating conditions.
- In October 2019, based on field estimates, total Company sales volumes averaged approximately 11,400 boe/d (comprised of 43 percent condensate and 50 percent total liquids), approximately 450 boe/d was attributable to production from South of the Wapiti River which was restarted mid-October. North of the Wapiti River production in October continued to be affected by significant third-party facility downtime and other capacity restrictions. All 20 tied-in wells North of the Wapiti River have been tested and produced since start-up, but at no point have all tied-in wells produced simultaneously. Based on the observed production performance to date, the Company is re-affirming its 2019 exit guidance of 14,000 – 16,000 boe/d for average December production.
- During Q3 2019, the Company entered into a $30 million midstream transaction with Tidewater, the transaction provides the capital required to construct the East Battery (located at the 5-14 pad-site). The initial $14 million of capital received by Pipestone Energy from the sale of the project to Tidewater in mid-August was allocated to accelerate a three-well completion program at the 9-14 pad in the Eastern portion of the acreage position in late Q3 2019. The approximately $16 million remaining balance to construct the East Battery will be funded by Tidewater in installments as construction commences after-break-up in mid-2020.
- During Q3 2019, Pipestone Energy successfully completed 3 wells (3 net) with an average lateral length of approximately 3,000 metres at its 9-14 pad-site. These wells were completed utilizing limited entry ("XLE") high intensity plug and perf designs with proppant loading of 2.5 T/M and will be brought on-stream in early 2020. The completion costs incurred in Q3 2019 with respect to these wells were $4.0 million per well. These costs are representative of completion costs expected in development mode as they are exclusive of the downhole logging and other reservoir data collection activity undertaken, and exclusive of extended flowback testing, which will be completed in Q1 2020.
- In early September, drilling operations commenced at the 6-24 pad-site. A total of six wells are planned to be drilled on the 6-24 pad this fall. Two wells were drilled and rig released in September, the remaining four wells will be drilled in Q4 2019. Afterwards the rig will be moved to the 6-30 pad and commence drilling out another six well pad.
- Pipestone Energy continued its robust commodity price risk management program, which is primarily designed to reduce cash flow volatility, enhance certainty regarding funding availability for the Company's capital expenditure program, and service debt.

Outlook

Since closing the successful merger with Blackbird on January 4th, 2019, the Company has met all of the critical development and capital expenditure milestones required to achieve its 2019 exit production guidance of 14,000 to 16,000 boe per day for December 2019. The commissioning of the third-party processing facilities and the September start-up of the North of the Wapiti River production ahead of schedule reaffirms this guidance.

The Company's 2019 net capital investment program continues to be on-track, on-time, and has been achieved under budget. Based on this performance, Pipestone Energy is accelerating six completions at its 6-24 pad-site into December 2019 from Q1 2020. The planned capital expenditures to be incurred in 2019 towards these six completions is approximately $20 million. The resulting net capital guidance for 2019 remains within the top-end of our previously announced 2019 guidance at approximately $155 million. The 2019 capital program has been focused on drilling, completing, and tying-in condensate-rich Montney wells, and on the build-out of the required infrastructure that will enable Pipestone Energy to grow efficiently in future years. Based on the infrastructure build-out completed in 2019, Pipestone Energy has the capacity to grow its production to approximately 33,000 boe/day without incurring additional significant infrastructure expenditures. Consequently 2020 capital guidance, which is expected to be released by the end of January 2020, will be primarily weighted towards drilling and completion activity.

Pipestone Energy is in the initial stage of executing a multi-year development strategy that is focused on generating top decile, full-cycle investment returns and exceed cashflow generation hurdles based on a flat future price deck of US$55 per bbl WTI crude oil and $1.40 per GJ AECO natural gas. Given its current outlook on commodity prices, and the actions taken to capture these prices through its hedging program, Pipestone Energy is confident it can meet its future development objectives.

Capital Expenditures

($ thousands)	Three months ended September 30, 2019	2018	Nine months ended September 30, 2019	2018
	$	$	**$**	$
Drilling	**4,861**	2,222	**13,975**	19,605
Completions	**15,824**	1,519	**37,630**	22,373
Production equipment and facilities	**6,885**	705	**66,850**	2,209
Land and other	**1,040**	982	**4,672**	4,825
Capitalized G&A	**824**	-	**2,609**	-
Total capital expenditures, per cash flow statement	**29,434**	5,428	**125,737**	49,012
Acquisitions	**98**	1,098	**214**	1,098
Proceeds on asset under construction	**(13,967)**	-	**(13,967)**	-
Exploration and evaluation from Corporate Acquisition	**-**	-	**36,942**	-
Property and equipment from Corporate Acquisition	**-**	-	**197,755**	-
	15,565	6,526	**346,681**	50,110
Right-of-use lease assets from Corporate Acquisition	**-**	-	**1,630**	-
Right-of-use lease additions	**-**	-	**1,536**	-
	15,565	6,526	**349,847**	50,110

2019 is a transformational year for Pipestone Energy as it has built out significant infield infrastructure which is now connected to third-party processing and egress. The Company has also drilled and completed wells North of the Wapiti River with the initial production from these wells commencing in mid-September. As such, the 2019 capital program is ambitious and represents a significant investment prior to the full realization of commercial production.

At September 30, 2019, the Company had exploration and evaluation assets of $43.1 million (December 31, 2018 – $6.7 million). This included 86,147 net acres of undeveloped land.

At September 30, 2019, the Company had property and equipment of $494.8 million. This included developed land and costs associated with the wells the Company has drilled and acquired to date. As well, it included $0.5 million incurred since inception to purchase computer hardware and software, associated office furniture and office improvements for use by Pipestone Energy employees and consultants to evaluate liquids and natural gas opportunities. Additionally, under IFRS 16, *Leases*, Pipestone Energy included $2.7 million associated with right-of-use ("ROU") assets included in property and equipment relating to a field office, field equipment leases and a corporate office lease.

For the three-month period ended September 30, 2019, Pipestone Energy successfully executed and accelerated its Montney-focused development program by:

- Divesting its East Battery project to Tidewater for $14 million of proceeds;
- Re-directing the funds from the above divestiture into accelerating the completion of its 3 wells (3 net) located at the 9-14 pad utilizing XLE high intensity plug and perf designs;
- Finalizing the equipping of its 3-01 pad-site facility for production the start-up in mid-September 2019; and
- Drilling and rig releasing 2 wells (2 net) from its 6-24 pad.

Pipestone Energy exited Q3 2019 on-track and overall under-budget with respect to the 2019 capital program.

Drilling activity

Montney well activity [(1)]	Three months ended September 30, 2019	2018 [(2)]	Nine months ended September 30, 2019	2018 [(2)]
Gross				
Wells drilled (rig-released)	**2.0**	1.0	**6.0**	7.0
Wells completed	**3.0**	-	**10.0**	3.0
Net				
Wells drilled (rig-released)	**2.0**	1.0	**6.0**	6.9
Wells completed	**3.0**	-	**10.0**	3.0

(1) Well counts include all horizontal Montney wells and exclude water injection wells, and wells that were re-drilled or abandoned. Drilling counts are based on rig release date and brought on production counts are based on the first production date after the wells were tied in to permanent facilities.

(2) The comparative figures presented for 2018 are that of the predecessor company, Pipestone.

Financial and Operating Results

Production

	Three months ended September 30, 2019	2018	Nine months ended September 30, 2019	2018
Daily average volume				
Condensate and crude oil *(bbls/d)*	**1,112**	-	**600**	97
NGL *(bbls/d)*	**139**	-	**82**	-
Natural gas *(Mcf/d)*	**7,298**	-	**4,011**	-
Total sales *(boe/d)*	**2,467**	-	**1,351**	97
Total sales *(boe)*	**226,979**	-	**368,716**	26,378
Production weighting				
Condensate and crude oil	**45%**	-%	**44%**	100%
NGL	**6%**	-%	**6%**	-%
Natural gas	**49%**	-%	**50%**	-%
	100%	-%	**100%**	100%

Starting in September, Pipestone Energy began bringing on-production from North of the Wapiti River at its 15-14 and 3-01 pad-sites, with approximately 4,700 boe per day (comprised of 46 percent condensate and 53 percent total liquids) produced from these two pads in September. The majority of the Company's North of the Wapiti River production capability remained unrealized at quarter-end and is being brought on-production gradually throughout Q4 2019. Pipestone Energy's production from North of the Wapiti River will be processed either at the Keyera Wapiti Plant or Tidewater Pipestone Gas Plant. North of the Wapiti River production has continued to ramp-up in October and November as additional wells have been brought on from the 15-14 and the 03-01 pad-sites as well as from one well on the 6-24 pad-site, and as the third-party infrastructure run times have improved.

In October 2019, based on field estimates, total Company sales volumes averaged approximately 11,400 boe/d (comprised of 43 percent condensate and 50 percent total liquids), approximately 450 boe/d was attributable to production from South of the Wapiti River which was restarted mid-October. North of the Wapiti River production in October continued to be affected by significant third-party facility downtime and other capacity restrictions. All 20 tied-in wells North of the Wapiti River have been tested and produced since start-up, but at no point have all tied-in wells produced simultaneously. Based on the observed production performance to date, the Company is re-affirming its 2019 exit guidance of 14,000 – 16,000 boe/d for average December production.

The South of the Wapiti River legacy production acquired in the Corporate Acquisition represented approximately 35 percent of the Company's production volumes in Q3 2019. This production was shut-in during September 2019 due to third-party facility planned turn-around.

All production in the 2018 comparative periods relates to Predecessor Pipestone test production, and thus is unpredictable and not representative of well capability once on full-time production.

In Q4 2018 the Government of Alberta mandated production curtailments for crude oil by larger producers throughout the province. In Q3 2019 the Government of Alberta increased the crude oil curtailment levels to 20,000 bbls per day from the previous 10,000 bbls per day. The curtailments are not expected to significantly affect the Company's condensate production, as condensate is not a part of the curtailment program.

Sales

($ thousands, except per unit amounts)	Three months ended September 30, 2019	2018	Nine months ended September 30, 2019	2018
	$	$	**$**	$
Condensate and crude oil	**6,666**	-	**10,873**	1,569
NGL	**161**	-	**435**	-
Natural gas	**981**	-	**2,417**	-
Total	**7,808**	-	**13,725**	1,569
Average realized prices before hedging and transportation				
Condensate and crude oil *($/bbl)*	**65.17**	-	**66.36**	59.50
NGL *($/bbl)*	**12.57**	-	**19.43**	-
Natural gas *($/Mcf)*	**1.46**	-	**2.21**	-
Combined average *($/boe)*	**34.40**	-	**37.21**	59.50

Benchmark Pricing

	Three months ended September 30, 2019	2018	Nine months ended September 30, 2019	2018
	$	$	**$**	$
Average crude oil prices				
WTI crude oil *(US$/bbl)* (1)	**56.44**	69.68	**57.04**	66.83
WTI crude oil *(C$/bbl)*	**74.52**	79.52	**75.82**	83.62
Average condensate prices				
Edmonton Condensate *(C$/bbl)*	**68.24**	80.30	**70.21**	83.37
Average natural gas prices				
AECO 5A natural gas *(C$/GJ)* (2)	**0.96**	1.19	**1.49**	1.43
Chicago City Gate natural gas *(C$/GJ)* (3)	**2.63**	3.54	**3.13**	3.40
Average foreign exchange rate				
Exchange rate *(US$/C$)*	**0.76**	0.77	**0.75**	0.78

(1) WTI refers to the West Texas Intermediate crude oil price.

(2) AECO refers to the Alberta Energy Company natural gas price. 5A is a simple average of the daily spot prices.

(3) Chicago City Gate refers to the Chicago Index Futures natural gas price.

Substantially all of Pipestone Energy's condensate and crude oil production is delivered and sold in Edmonton, Alberta, through the Pembina pipeline system. The price of WTI for crude oil sales at Cushing, Oklahoma is the primary benchmark for crude oil pricing in North America. Despite some recent volatility, the price that Alberta condensate producers receive for their condensate production has historically been correlated to the price of WTI, adjusted for Edmonton differentials, external supply and demand, changes in Canada-U.S. exchange rates, transportation costs and quality. As such, the Company has hedged certain expected future volumes to WTI directly in C$ and the Company has also hedged a subset of volumes to the differential between WTI and Edmonton Condensate ("EdCon"). EdCon refers to the Enbridge condensate pool price for liquids sales at Edmonton, Alberta which is the primary reference price for condensate in Western Canada (see the *"Commodity Price Risk Management"* section).

The Company has entered into various firm service contracts to transport its natural gas production volumes as scheduled to come on-stream during Q4 2019. Prior to the September 2019 start-up of the North of the Wapiti River production, Pipestone Energy primarily utilized its firm service contract for 5.0 MMcf per day of natural gas to

Chicago through the Alliance Pipeline (which represented the majority of the Company's first-half natural gas production), as well as access in Alberta on the NGTL system. During September, the Company sold all of its natural gas production through the Nova Gas Transmission Line ("NGTL") system. The AECO 5A price is the primary benchmark for the Company's current natural gas sales. The AECO 5A differentials to other North American benchmarks can fluctuate significantly, primarily due to limited economic transportation and options out of Western Canada, increasing domestic production and limited access to local storage facilities.

Royalties

	Three months ended September 30,		Nine months ended September 30,	
	2019	2018	**2019**	2018
	$	$	**$**	$
Royalties *($ thousands)*	**421**	-	**719**	110
Per boe *($)*	**1.85**	-	**1.95**	4.19
Percentage of sales	**5.4%**	-	**5.2%**	7.0%

Pipestone Energy's royalty burden is predominately paid to the Province of Alberta, with minimal gross over-riding royalties applicable on a portion of the Company's production sales. The royalty rates are indicative of royalty rates on new production in Alberta.

Royalties increased on a total basis from the comparative periods in 2018 due to the initial start-up production from the 15-14 and 3-01 pad-sites, which began producing in September 2019, and from production volumes attributable to the Corporate Acquisition.

Operating Expense

	Three months ended September 30,		Nine months ended September 30,	
	2019	2018	**2019**	2018 [(1)]
	$	$	**$**	$
Operating expense *($ thousands)*	**3,470**	74	**5,633**	257
Per boe *($)*	**15.29**	-	**15.27**	9.80

(1) IFRS 16, *Leases*, was adopted on January 1, 2019 using the modified retrospective approach; therefore, comparative information was not restated. See "Critical Accounting Judgments, Estimates and Policies".

Operating costs are mainly comprised of third-party gathering and processing fees, lease rentals, road and lease maintenance, chemicals, fuel, well site operation and supervision activities and property taxes.

Operating expenses increased on a total basis from the comparative periods in 2018 due to the initial start-up of production from the 15-14 and 3-01 pad-sites, which began producing in September 2019 and operating expenses attributable to the Corporate Acquisition production from South of the Wapiti River.

The current per boe expense burden is high at this early stage of Pipestone Energy's development as a number of fixed operating costs have been spread over the limited 2019 production volumes and also due to the start-up of third-party processing facilities. The Company experienced abnormally high shrinkage rates on its production delivered to third-party processing facilities at the end of September, due to flaring and other expected start-up challenges encountered. Pipestone Energy expects the start-up issues to dissipate and fixed costs to be allocated over higher volumes in future periods which will result in a lower operating expense per boe.

Transportation Expense

	Three months ended September 30,		Nine months ended September 30,	
	2019	2018	**2019**	2018
	$	$	**$**	$
Transportation expense *($ thousands)*	**1,283**	-	**2,679**	-
Per boe *($)*	**5.65**	-	**7.26**	-

The Company has entered into various firm service contracts to transport its current and future expected production volumes as scheduled to come on-line in Q4 2019. Transportation expense primarily consist of tolls on the Pembina

Peace, TC Pipelines (TCPL), NGTL and Alliance pipeline systems. Pipestone Energy incurs transportation charges on the sales volumes that it delivers to specified sales hubs that are beyond its third-party processing facilities under committed agreements.

In Q1 and part of Q2 2019, Pipestone Energy had very low actual transported volumes as production was limited to the legacy production from the Corporate Acquisition and the third-party plant this production was processed through experienced several shut-downs, however, the firm service and take-or-pay condensate and gas handling commitments listed below, remained effective, and the resulting transportation expense for 2019 was high on a per boe basis. These firm service and take-or-pay contracts included:

- Take-or-pay gas handling agreement for 5 MMcf per day of processed gas on the Alliance pipeline to the Alliance Chicago Exchange Hub until October 31, 2021;
- Firm service agreement providing for the transportation of 3.5 MMcf per day through the TCPL system until September 2020; and
- Firm service agreement providing for the transportation of 1,000 bbls per day of condensate through Pembina's pipeline system until September 2027.

In Q3 2019 Pipestone Energy continued to incur costs related to the above-mentioned contracts as well as additional transportation costs on its initial North of the Wapiti River gas volumes delivered through the NGTL system and on its liquids volumes delivered through the Pembina Peace pipeline during September 2019.

Commodity Price Risk Management

During 2019 Pipestone Energy began to execute its commodity price risk management program which is primarily designed to reduce cash flow volatility, enhance certainty on funding availability for the Company's capital expenditure program and service debt.

Mitigation of cash flow volatility is an integral component of the Company's business strategy. Business conditions are monitored regularly and reviewed with the Board of Directors to establish risk management guidelines used by management in carrying out the Company's strategic risk management program. A Risk Management Committee has been established by the management team, which meets regularly and on an ad hoc basis to review the commodity markets, current hedge positions, and opportunities for optimization.

Pipestone Energy continues to implement an on-going hedge program, currently focused on its forecast liquids production due to the disproportionate revenue anticipated from these products as compared to the revenue from its anticipated natural gas production. Pipestone Energy utilizes a variety of hedging structures, including fixed price swaps, collars, and product differential hedges. To date, Pipestone Energy has entered into hedges with respect to benchmark WTI, as well as EdCon (Edmonton condensate) directly. Price and volume targets for the Company's hedge portfolio are established based on macro supply and demand fundamental analysis, Pipestone Energy's future production expectations and target development rates.

The Company also entered into forward swaps on the differential between the Net Canadian Energy Monthly Index Edmonton C5+ price and WTI, traded in US$ per barrel on the Chicago Mercantile Exchange. A fixed-price Edmonton C5+ swap can be generated through the combination of a WTI swap and an Edmonton C5+ differential swap. This hedge product was added to Pipestone Energy's portfolio during Q2 2019.

The Company has elected not to use hedge accounting and, accordingly, the fair value of the commodity financial derivative instruments is recorded at each period-end. The fair value may change substantially from period to period depending on commodity forward strip prices for the contracts outstanding at the balance sheet date. The change in fair value from period-end to period-end is reflected in profit or loss for that period. As such, if benchmark prices rise during the period, the Company records a loss based on the change in price multiplied by the volume hedged. If benchmark prices fall during the period, the Company records a gain. The prices used to record the actual gain or loss are subject to an adjustment for volatility. Pipestone Energy's financial results should be viewed with the understanding that the estimated future gain or loss on financial derivative instruments is recorded in the current period's profit or loss, while the estimated future value of the underlying physical sales is not.

Commodity financial derivative instruments

	Three months ended September 30,		Nine months ended September 30,	
	2019	2018	**2019**	2018
	$	$	**$**	$
Realized loss on commodity financial derivative instruments *($ thousands)*	**-**	-	**(122)**	-
Per boe *($)*	**-**	-	**(0.33)**	-
Unrealized gain on commodity financial derivative instruments *($ thousands)*	**5,834**	-	**13,391**	-
Per boe *($)*	**25.70**	-	**36.32**	-

The realized loss on commodity financial derivative instruments during the nine months ended September 30, 2019 was due to the crude oil price being higher than the upper collar price in April and May. The one commodity financial derivative instrument that was active during the three and nine months ended September 30, 2019 is a collar on C$ WTI.

The unrealized gain on commodity financial derivative instruments during the three and nine months ended September 30, 2019 was due to decreases in crude oil as well as Edmonton Condensate futures, partially offset by increases in AECO futures.

The Company had the following weighted-average condensate and crude oil commodity financial derivative instruments at September 30, 2019:

	C$ WTI collars		C$ WTI swaps		EdCon basis swaps		EdCon fixed price swaps		AECO 5A swaps	
Term	**bbls/d**	**C$/bbl**	**bbls/d**	**C$/bbl**	**bbls/d**	**US$/bbl**	**bbls/d**	**C$/bbl**	**GJ/d**	**C$/GJ**
Oct. – Dec. '19	518	67.60 – 79.14	1,292	81.11	1,000	(5.58)	1,489	75.13	19,026	1.93
Jan. – Mar. '20	731	70.47 – 80.45	2,800	79.11	2,000	(5.63)	-	-	19,000	1.79
Apr. – Jun. '20	500	73.00 – 81.60	2,800	79.11	2,000	(5.63)	-	-	26,125	1.68
Jul. – Sept. '20	-	-	3,400	78.15	1,000	(5.75)	-	-	26,125	1.68
Oct. – Dec. '20	-	-	2,750	77.90	1,000	(5.75)	-	-	19,826	1.70

Interest rate financial derivative instruments

	Three months ended September 30,		Nine months ended September 30,	
	2019	2018	**2019**	2018
	$	$	**$**	$
Unrealized gain (loss) on interest rate financial derivative instruments *($ thousands)*	**677**	370	**472**	(300)
Per boe *($)*	**2.98**	-	**1.28**	(11.37)

Pipestone Energy's interest rate financial derivative instruments constitute floating to fixed interest rate swaps with the lending institutions, resulting in the bank debt bearing fixed interest rates. Due to the nature of the bank debt and the swaps being with the lending institutions, the realized portion of the interest rate financial derivative instruments is recorded as financing expense.

General and Administrative (G&A) Expenses

($ thousands, except per boe amounts)	Three months ended September 30, 2019	2018	Nine months ended September 30, 2019	2018
	$	$	**$**	$
Gross G&A expenses	**3,009**	522	**9,599**	1,202
Capitalized G&A	**(824)**	-	**(2,609)**	-
Overhead recoveries	**-**	-	**(32)**	-
G&A expenses	**2,185**	522	**6,958**	1,202
Per boe	**9.62**	-	**18.87**	45.57

G&A expenses primarily consist of the Company's overhead costs incurred to support its ongoing operations and planned future operations. Capitalized G&A is directly attributable to the development of the Pipestone Energy assets. Overhead recoveries relate to recovered amounts from partners for operating administration costs as well as capital programs. Capitalized G&A and overhead recoveries are consistent with industry practice. For the quarter and year-to-date 2019 Pipestone Energy capitalized 27 percent of gross G&A expenses.

G&A expenses were higher than in the comparative periods of 2018 predominantly due to higher employee and consulting expenses associated with increased activity in 2019 and a number of one-time integration expenditures relating to the Corporate Acquisition. In addition, the current per boe expense burden is high at this stage of Pipestone Energy's development as Pipestone Energy has scaled its business in anticipation of increased production volumes this fall. As a result, 2019 there are a number of fixed and step variable G&A expenses spread over relatively limited 2019 production volumes.

Transaction Expenses

	Three months ended September 30, 2019	2018	Nine months ended September 30, 2019	2018
	$	$	**$**	$
Transaction *($ thousands)*	**59**	-	**4,305**	-
Per boe *($)*	**0.26**	-	**11.67**	-

Transaction expenses were incurred through services related to the Corporate Acquisition, which closed January 4, 2019. These include fees for financial advisors, legal consultations, due diligence and reservoir engineers.

Share-based compensation

	Three months ended September 30, 2019	2018	Nine months ended September 30, 2019	2018
	$	$	**$**	$
Share-based compensation *($ thousands)*	**253**	-	**331**	-
Per boe *($)*	**1.11**	-	**0.90**	-

Share-based compensation relates to stock options, performance share units (PSUs) and restricted share units (RSUs) granted to employees, officers and directors during Q2 and Q3 2019.

Exploration and Evaluation ("E&E") Expenses

	Three months ended September 30, 2019	2018	Nine months ended September 30, 2019	2018
	$	$	**$**	$
E&E *($ thousands)*	**1,700**	-	**1,700**	-
Per boe *($)*	**7.49**	-	**4.61**	-

E&E expenses relates to mineral rights expiries during Q3 2019 for assets acquired in the Corporate Acquisition.

Depletion and Depreciation ("D&D") Expenses

	Three months ended September 30, 2019	2018	Nine months ended September 30, 2019	2018
	$	$	**$**	$
D&D *($ thousands)*	**2,689**	-	**4,468**	306
Per boe *($)*	**11.85**	-	**12.12**	11.61

D&D expenses primarily consist of depletion of Company liquids and natural gas properties on a unit-of-production basis over total proved plus probable reserves before royalties. The unit-of-production rate takes into account expenditures incurred to date, together with estimated future development expenditures required to develop those proved plus probable reserves. This rate, calculated at a component level, is then applied to Pipestone Energy's production volume to determine D&D in a given period. Management believes that this method of calculating D&D expenses over each boe is equivalent with its proportionate share of the cost of capital invested over the total estimated life of the related asset as represented by proved plus probable reserves. Future development costs included during the three and nine months ended September 30, 2019 are $1.3 billion.

D&D expenses also include depreciation of the Company's ROU assets on a straight-line basis over the shorter of the estimated useful life or the lease term. The Company's D&D expense increased marginally from the comparative period in 2018 due to the introduction of ROU asset amortization as a result of the adoption of IFRS 16, *Leases*, as of January 1, 2019.

Financing Expense

($ thousands, except per boe amounts)	Three months ended September 30, 2019	2018	Nine months ended September 30, 2019	2018 [(1)]
	$	$	**$**	$
Letter of credit fees	**371**	-	**1,410**	-
Interest on bank debt	**2,874**	-	**6,352**	141
Bank charges	**-**	-	**-**	1
Lease interest expense	**86**	-	**138**	-
Cash financing expense	**3,331**	-	**7,900**	142
Interest on bank debt	**-**	1,008	**-**	1,632
Accretion on decommissioning provisions	**27**	12	**82**	25
Amortization of financing costs	**864**	187	**1,759**	414
Non-cash financing expense	**891**	1,207	**1,841**	2,071
Total financing expense	**4,222**	1,207	**9,741**	2,213
Cash financing expense, per boe	**14.68**	-	**21.43**	5.38
Non-cash financing expense, per boe	**3.93**	-	**4.99**	78.51

(1) IFRS 16, *Leases*, was adopted on January 1, 2019 using the modified retrospective approach; therefore, comparative information was not restated. See "Critical Accounting Judgments, Estimates and Policies".

Interest on bank debt is the amount charged by Pipestone Energy's lending institutions.

Lease interest pertains to the interest rate implicit in the lease, or, if that rate cannot be determined, the Company's incremental borrowing rate. The interest rate applicable to each lease is applied to the lease liability and applied to each lease payment.

Accretion on decommissioning provisions increased from the 2018 comparative period as a result of having more wells, both as a result of drilling and from the Corporate Acquisition.

Amortization of financing costs relate to the amortization of bank due diligence fees related to Pipestone Energy's $198.5 million, first lien credit facility that matures on December 31, 2020 (the "Credit Facility") and the initial mark-to-market value of the interest rate swaps associated with the setup of the Credit Facility.

The current per boe expense burden for both the cash and non-cash financing expense is high at this stage of Pipestone Energy's development as the costs are spread over the relatively limited production volumes.

Financing Income

	Three months ended September 30,		Nine months ended September 30,	
	2019	2018	**2019**	2018
	$	$	**$**	$
Financing income *($ thousands)*	**207**	84	**771**	242
Per boe *($)*	**0.91**	-	**2.09**	9.17

Financing income relates to interest earned on cash held in bank accounts. Financing income was higher in 2019 than in the 2018 periods, due to higher bank balances.

Income Tax

The deferred income tax was recoveries of $0.3 million and $7.5 million for the respective three and nine months ended September 30, 2019, compared to recoveries of $Nil and $0.1 million in the respective 2018 periods. The recovery in the nine months ended September 30, 2019 is largely due to a $3.2 million benefit associated with a previously unrecognized deferred income tax asset now being recognized and applied against deferred income tax liabilities acquired in the Corporate Acquisition, as well as the reductions in the Alberta corporate income tax rate.

Pipestone Energy's estimated consolidated tax pools are summarized as follows:

($ thousands)	**As at September 30, 2019**	As at December 31, 2018
	$	$
Canadian oil and gas property expense	**32,576**	17,056
Canadian development expense	**113,574**	64,806
Canadian exploration expense	**45,080**	25,969
Non-capital losses	**209,801**	65,323
Undepreciated capital cost ("UCC") pools [1]	**83,336**	25,438
Debt and share issuance costs	**6,454**	1,939
	490,821	200,531

[1] Substantially all of the Company's UCC pools relate to Class 41 assets, which are deductible at a rate of 25 percent per year.

The above tax pools include non-capital losses that expire in 2024 through 2038.

Loss

The Company incurred losses of $1.4 million ($0.01 per share basic and diluted) and $0.8 million ($0.00 per share basic and diluted) for the respective three and nine months ended September 30, 2019, compared to losses of $1.3 million ($0.03 per share basic and diluted) and $2.5 million ($0.05 per share basic and diluted) for the respective comparative periods in 2018. The losses in 2018 and 2019 resulted mainly from interest expense on bank debt. The loss for the nine months ended September 30, 2019 was largely offset from unrealized gains on commodity financial derivative instruments, as well as one-time income tax gains associated with reductions in the Alberta corporate income tax rate and a previously unrecognized deferred income tax asset now being recognized and applied against deferred income tax liabilities acquired in the Corporate Acquisition.

Supplemental Information

The following table summarizes key financial and operating information for the periods indicated.

Netback Analysis

	Three months ended September 30, 2019	Three months ended September 30, 2018	Nine months ended September 30, 2019	Nine months ended September 30, 2018 [(1)]
	$	$	**$**	$
Average sales price	**34.40**	-	**37.21**	59.50
Royalties	**(1.85)**	-	**(1.95)**	(4.19)
Operating expense	**(15.29)**	-	**(15.27)**	(9.80)
Transportation expense	**(5.65)**	-	**(7.26)**	-
Operating netback [(2)]	**11.61**	-	**12.73**	45.51
G&A expense	**(9.62)**	-	**(18.87)**	(45.57)
Transaction costs	**(0.26)**	-	**(11.67)**	-
Realized loss on commodity financial derivative instruments	**-**	-	**(0.33)**	-
Financing income	**0.91**	-	**2.09**	9.17
Financing expense	**(14.68)**	-	**(21.43)**	(5.38)
Funds flow netback [(2)]	**(12.04)**	-	**(37.48)**	3.73
Financing expense – non-cash	**(3.93)**	-	**(4.99)**	(78.51)
D&D expense	**(11.85)**	-	**(12.12)**	(11.61)
E&E expense	**(7.49)**	-	**(4.61)**	-
Share-based compensation	**(1.11)**	-	**(0.90)**	-
Unrealized gain (loss) on interest rate financial derivative instruments	**2.98**	-	**1.28**	(11.37)
Unrealized gain on commodity financial derivative instruments	**25.70**	-	**36.32**	-
Deferred income tax recovery	**1.53**	-	**20.22**	2.20
Loss per boe	**(6.21)**	-	**(2.28)**	(95.56)

(1) IFRS 16, *Leases*, was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information was not restated. See "Critical Accounting Judgments, Estimates and Policies".

(2) See "Non-GAAP measures".

The per boe costs related to the netback for 2019 were high given the stage of Pipestone Energy's development, as a number of fixed costs were spread over the limited production volumes.

Selected Quarterly Information

Three months ended	**Sept. 30, 2019**	**June 30, 2019**	March 31, 2019	Dec. 31, 2018 (2)(4)	Sept. 30, 2018 (2) (4)	June 30, 2018 (2) (4)	March 31, 2018 (2) (4)	Dec. 31, 2017 (2) (4)
Financial ($ thousands, except per share amounts and share numbers)								
Sales of liquids and natural gas	**7,808**	5,917	460	59	-	598	971	-
Cash from (used in) operating activities	**(6,626)**	(777)	(12,785)	(3,490)	(361)	(180)	163	(39)
Funds flow from (used in) operations	**(2,734)**	(2,423)	(8,663)	(8,260)	(512)	132	480	(114)
Per share, basic and diluted *($)* (1)	**(0.01)**	(0.01)	(0.05)	(0.14)	(0.01)	0.00	0.01	(0.00)
Income (loss)	**(1,409)**	4,869	(4,302)	(9,603)	(1,349)	(539)	(631)	(86)
Per share, basic and diluted *($)* (1)	**(0.01)**	0.03	(0.02)	(0.16)	(0.03)	(0.01)	(0.01)	(0.00)
Capital expenditures	**29,434**	46,835	49,468	60,252	5,428	13,026	30,558	7,724
Total assets *(end of quarter)*	**607,287**	579,297	531,994	216,300	147,240	128,644	144,740	99,954
Working capital (deficit) *(end of quarter)*	**20,893**	(8,026)	2,411	(20,180)	10,332	(2,630)	10,264	10,201
Bank debt *(end of quarter)*	**156,983**	115,754	80,735	53,436	52,187	30,992	30,181	-
Shareholders' equity *(end of quarter)*	**382,867**	383,843	378,896	114,058	85,661	87,010	87,549	88,180
Weighted-average basic shares outstanding *(000s)* (1)	**189,627**	187,096	184,540	60,707	52,782	52,782	52,782	45,078
Weighted-average diluted shares outstanding *(000s)* (1)	**189,627**	187,116	184,540	60,707	52,782	52,782	52,782	45,078
Operations								
Production								
Condensate and crude oil *(bbls/d)*	**1,112**	595	82	73	-	106	186	-
NGL *(bbls/d)*	**139**	88	17	-	-	-	-	-
Natural gas *(Mcf/d)*	**7,298**	4,341	318	-	-	-	-	-
Total *(boe/d)*	**2,467**	1,407	152	73	-	106	186	-
Condensate and crude oil *(% of total production)*	**45**	42	54	100	-	100	100	-
Total liquids *(% of total production)*	**51**	49	65	100	-	100	100	-
Average realized prices *($)*								
Condensate and crude oil *(per bbl)*	**65.17**	71.83	42.71	8.60	-	61.94	58.00	-
NGL *(per bbl)*	**12.57**	29.24	25.04	-	-	-	-	-
Natural gas *(per Mcf)*	**1.46**	3.37	3.69	-	-	-	-	-
Operating netback *(per boe)* (3)	**11.61**	20.92	(45.09)	(6.93)	-	51.25	46.54	-
Funds flow netback *(per boe)* (3)	**(12.04)**	(18.93)	(631.58)	(1,221.29)	-	13.50	28.69	-

(1) The number of common shares have been adjusted retrospectively to reflect the 10:1 share consolidation, as well as the 0.5996 exchange ratio, as part of the Corporate Acquisition.

(2) IFRS 16, *Leases*, was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information was not restated. See "Critical Accounting Judgments, Estimates and Policies".

(3) See "Non-GAAP measures".

(4) The comparative figures presented for 2018 and 2017 are that of the predecessor company, Predecessor Pipestone.

Inherent to the nature of the oil and natural gas industry, fluctuations in Pipestone Energy's quarterly sales of liquids and natural gas, funds flow from or used in operations, and income or loss are primarily caused by variations in production volumes, realized commodity prices and the related impact on royalties, realized and unrealized gains or losses on financial instruments, changes in per-unit expenses, and deferred income taxes. Please refer to "Financial and Operating Results" above for an explanation of changes.

Share Capital

As at the date of this MD&A, the Company had 189.7 million common shares, 175.2 million warrants, 1.4 million stock options, 0.6 million PSUs and 0.8 million RSUs outstanding. Each warrant is exercisable for 0.1 common shares of the Company.

Related Party Transactions

During the three and nine months ended September 30, 2019, Pipestone Energy accrued $0.6 million and $3.6 million, respectively, of G&A expenses from CNOR LP. At September 30, 2019, $5.0 million (December 31, 2018 – $4.8 million) was included in accounts payable and accrued liabilities and was due under normal credit terms. All related-party transactions are recorded at the exchange amount.

Liquidity and Capital Resources

At September 30, 2019, the Company had an adjusted working capital surplus of $12.7 million (December 31, 2018 – adjusted working capital deficit of $20.2 million), excluding the interest rate and commodity financial derivative instrument assets and liabilities, as well as lease liabilities. Net cash used in operations for the three and nine months ended September 30, 2019 was $6.6 million and $20.2 million, respectively. Funds flow used in operations for the three and nine months ended September 30, 2019 was $2.7 million and $13.8 million, respectively.

Available Funding

($ thousands)	As at September 30, 2019	2018 [1]
	$	$
Current assets	**66,730**	17,896
Current liabilities	**45,837**	7,564
Working capital surplus (deficit)	**20,893**	10,332
Less: current asset commodity financial derivative instruments	**(10,738)**	-
Plus: current liability interest rate financial derivative instruments	**1,983**	-
Plus: current lease liabilities	**519**	-
Adjusted working capital surplus (deficit) [2]	**12,657**	10,332
Plus: Credit Facility capacity [3]	**19,998**	6,228
Available funding [2]	**32,655**	16,560

(1) IFRS 16, *Leases*, was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information was not restated. See "Critical Accounting Judgments, Estimates and Policies".

(2) See "Non-GAAP measures".

(3) As at September 30, 2019, Pipestone Energy has a $198.5 million Credit Facility, which is reduced by $17.8 million in issued letters of credit and $160.7 million of principal drawn.

Bank Debt

Pipestone Energy has a $198.5 million, first lien Credit Facility that matures on December 31, 2020. The Credit Facility is comprised of a $10.0 million revolving operating line, a $20.0 million letter of credit facility, and a $168.5 million delayed-draw term loan (the "Term Loan"). The Term Loan is funded in fixed tranches to fund capital expenditures and general corporate expenses. Interest on the operating line and letter of credit facility is payable in cash, while interest on the Term Loan is added to the debt balance. The Credit Facility is not subject to any scheduled borrowing base redeterminations. Pipestone Energy is required to adhere to an "approved budget" with an allowable variance on capital expenditures. Standby fees are charged on the undrawn Credit Facility at a rate of 0.50 percent and the Company has entered into two separate floating-to-fixed interest rate swaps with the lending institutions.

The initial swap entered into on March 12, 2018 and resulted in the 2018 funding of $50.0 million ($30.0 million in March 2018 and $20.0 million in July 2018) bearing a fixed annual interest rate of 7.75 percent for the term from March 12, 2018 to February 28, 2019, 7.25 percent from March 1, 2019 to September 2, 2019 and 6.85 percent from September 3, 2019 to March 12, 2020.

The second swap entered into just prior to the closing of the Corporate Acquisition and resulted in the 2019 funding of $100.0 million ($10.0 million in January 2019, $20.0 million in March 2019, $32.5 million in June 2019 and $37.5

million in September 2019), bearing a fixed annual interest rate of 9.75 percent for the term from January 4, 2019 to March 31, 2020.

The remaining Term Loan, in the amount of $18.5 million, is to be used solely for interest and various fees that are due and payable up to March 31, 2020 with respect to the $150.0 million in funding during 2018 and 2019. Effective April 1, 2020 and until December 31, 2020 the Term Loan will bear an annual interest rate of 11.50 percent and will be payable in cash monthly. The Credit Facility terminates on December 31, 2020 at which time all amounts owing, including principal, interest and fees, are expected to be $167.9 million.

The Credit Facility is subject to various customary covenants, including restrictive covenants that limit Pipestone Energy's ability to, among other things, incur additional debt or guarantees; provide or incur liens on the assets; engage in mergers, consolidations, liquidation or dissolution; and make restricted payments. Pipestone Energy is permitted to enter into commodity swap contracts, as long as the completion schedule relating to the third-party Wapiti plant is on schedule, but not with a term exceeding 24 months or with an aggregate hedged amount exceeding 66 2/3 percent of the combined forecast average daily liquids and natural gas production (net of royalties) for the following 24 months.

At September 30, 2019 Pipestone Energy had drawn $160.7 million under the Term Loan:

($ Thousands)	As at September 30, 2019
	$
Credit facility – portion drawn	160,656
Unamortized debt issuance costs	(3,673)
Balance, end of period	**156,983**

In addition to the balance of $157.0 million, Pipestone Energy utilizes its letter of credit facility to securitize certain processing and transportation commitments. As at September 30, 2019, the Company had drawn $17.8 million on the letter of credit facility and was undrawn on the $10.0 million operating line.

As at and for the three and nine months ended September 30, 2019 the Company was in compliance with all covenants.

The Company generally relies on operating cash flows, equity issuances and its Credit Facility to fund its capital requirements and provide liquidity. The 2019 capital program is fully funded. In the future, the Company may access capital markets to meet additional financing needs and maintain flexibility in funding its capital programs. Future liquidity depends primarily on funds generated from operations, drawing on existing credit facilities and accessing debt and equity markets.

Capital Management

The Company's objective for managing capital is to maintain a strong balance sheet and available funding while providing financial flexibility to fund sustaining capital and to fund future high-return development growth. Near-term development activities are anticipated to be funded by the Company's funds flow, cash on hand, potential divestitures or draws under the credit facilities.

Pipestone Energy manages its liquidity risk through its capital structure, cash flow forecasting and available credit. The Company's 2019 net capital spending guidance of approximately $155 million is scheduled to be funded by draws on the Company's Credit Facility.

The Company as indicated above has significant financial liabilities and commitments over the next one to two years. The Company believes in the short term that its financial requirements will be addressed through its current and future lending arrangements and an increase in future operating cash flows as infrastructure projects are completed and production increases in the latter part of 2019. Over the near-term the Company will need to address its lending arrangements which mature at the end of 2020. The Company believes it will be successful in meeting its liquidity requirements, although uncertainty remains due to volatility in commodity prices and the economic environment, including identifying additional sources of equity or debt financing, in addition to reserve and production risk.

The Company strives for a proportion of debt to future cashflow which appropriately balances the level of risk being incurred by its capital investments.

Commitments and Contractual Obligations

At September 30, 2019, as part of its normal operations, Pipestone Energy had committed to paying the following undiscounted amounts over the next five years and thereafter as follows:

($ Thousands)	2019	2020	2021	2022	2023	Thereafter
	$	$	$	$	$	$
Gathering commitments	2,732	15,549	16,012	16,092	16,092	69,390
Processing commitments	2,251	15,100	23,140	25,283	25,283	84,219
Transportation commitments	3,857	17,178	19,277	20,328	20,328	124,138
Lease liabilities – principal	90	715	839	429	346	449
Lease liabilities – interest	71	248	168	99	64	29
Total payments	**9,001**	**48,790**	**59,436**	**62,231**	**62,113**	**278,225**

The lease liabilities are recognized on the Company's consolidated balance sheet. The gathering commitments, processing commitments, transportation commitments and interest on the lease liabilities are off-balance sheet arrangements in accordance with IAS 1, *Presentation of Financial Statements*.

Following the adoption of IFRS 16, *Leases*, on January 1, 2019, the Company recognized a lease liability on the consolidated statement of financial position for the majority of its non-cancellable lease arrangements. The Company elected to apply the practical expedient exemption to scope-out non-cancellable low-value and short-term lease arrangements. These out-of-scope contractual commitments are off-balance-sheet arrangements.

The Company is involved in legal claims arising in the normal course of business. The final outcome of such claims cannot be predicted with certainty and management believes that it has appropriately assessed any impact to the financial statements.

Critical Accounting Judgments, Estimates and Policies

The Company's critical accounting judgements, estimates and policies are described in notes 2 and 3 to the December 31, 2018 annual financial statements and in notes 2 and 3 to the September 30, 2019 condensed interim consolidated financial statements. Certain accounting policies are identified as critical because they require management to make judgments and estimates based on conditions and assumptions that are inherently uncertain, and because the estimates are of material magnitude to revenue, expenses, funds flow from operations, income or loss and/or other important financial results. These accounting policies could result in materially different results should the underlying conditions change, or the assumptions prove incorrect.

Critical accounting estimates are those requiring management to make particularly subjective or complex judgments about inherently uncertain matters. Estimates and underlying assumptions are reviewed on an ongoing basis and any revisions to accounting estimates are recognized in the same period.

Management's assumptions are based on factors that, in management's opinion, are relevant and appropriate, and may change over time as operating conditions change.

New accounting standards

IFRS 16, *Leases*, replaced IAS 17, *Leases*, and IFRIC 4, *Determining Whether an Arrangement Contains a Lease*. IFRS 16 requires entities to recognize lease assets and obligations on the balance sheet. For lessees, IFRS 16 removes the classification of leases as either operating leases or finance leases, effectively treating nearly all leases as finance leases. Certain short-term leases (less than 12 months) and leases of low-value assets are exempt from the requirements and may continue to be treated as operating leases.

The Company adopted the standard on the effective date of January 1, 2019 and applied the modified retrospective approach which does not require restatement of prior period financial information as the cumulative effect of applying the standard to prior periods is recorded as an adjustment to opening retained earnings. On initial adoption, management elected to use the following practical expedients permitted under the standard:

- Apply a single discount rate to a portfolio of leases with similar characteristics.
- Account for leases with a remaining term of less than 12 months as at January 1, 2019 as short-term leases.
- Account for lease payments as an expense and not recognize a right-of-use (ROU) asset if the underlying asset is of low dollar value.
- Apply hindsight in determining the lease term where the contract contains terms to extend or terminate the lease.

On adoption of IFRS 16, the Company recognized lease liabilities in relation to leases under the principles of the new standard. These liabilities were measured at the present value of the remaining leases payments, discounted using the Company's incremental borrowing rate as at January 1, 2019. The associated ROU asset were initially measured at the amount equal to the lease liability on January 1, 2019 with no impact on retained earnings.

Adoption of the new standard resulted in the recognition of an additional lease liability and corresponding ROU asset related to a field office lease. The impact of IFRS 16 is as follows:

- Lower operating expenses;
- Higher financing expenses due to the interest recognized on the lease obligation; and
- Higher depreciation expense related to the ROU asset.

The change in accounting policy affected the following items in the statement of financial position on January 1, 2019:

($ thousands)	January 1, 2019
	$
ROU asset presented in property and equipment	44
Current lease liability	33
Long-term lease liability	11

There are no other not-yet-effective IFRS or IFRIC interpretations that are expected to have a material impact on the Company.

Non-GAAP financial measures and additional subtotals in financial statements

Additional subtotal - funds flow from operations

Pipestone Energy uses "funds flow from operations" (cash from operating activities before changes in non-cash working capital and decommissioning provision costs incurred), a measure that is not defined under IFRS. Funds flow from operations should not be considered an alternative to, or more meaningful than, cash from operating activities, income (loss) or other measures determined in accordance with IFRS as an indicator of the Company's performance. Management uses funds flow from operations to analyze operating performance and leverage and believes it is a useful supplemental measure as it provides an indication of the funds generated by Pipestone Energy's principal business activities prior to consideration of changes in working capital.

The following table reconciles cash from operating activities to funds flow from operations:

($ thousands)	Three months ended September 30, 2019	2018	Nine months ended September 30, 2019	2018 [(1)]
	$	$	**$**	$
Cash used in operating activities	**(6,626)**	(361)	**(20,188)**	(378)
Decommissioning provision costs incurred	**3**	-	**3**	-
Changes in non-cash working capital	**3,889**	(151)	**6,365**	478
Funds flow from (used in) operations	**(2,734)**	(512)	**(13,820)**	100

(1) IFRS 16, *Leases*, was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information was not restated. See "Critical Accounting Judgments, Estimates and Policies".

Funds flow from operations was included in the condensed interim consolidated statement of cash flow in order to provide users with a better understanding of the key metrics utilized by Pipestone Energy to assess performance and how the calculation was arrived at. Accordingly, funds flow performance measures are not presented as non-GAAP measures in this MD&A.

Non-GAAP measures

This MD&A includes references to financial measures commonly used in the oil and natural gas industry. The terms "operating netback", "funds flow netback", "available funding", "net debt", "adjusted working capital", "CROIC", "ROCE" are not defined under IFRS, which have been incorporated into Canadian GAAP, as set out in Part 1 of the Chartered Professional Accountants Canada Handbook – Accounting, are not separately defined under GAAP, and may not be comparable with similar measures presented by other companies.

Management believes the presentation of the non-GAAP measures provide useful information to investors and shareholders as the measures provide increased transparency and the opportunity to better analyze and compare performance against prior periods.

Operating netback and funds flow netback

Operating netback is calculated on a per-unit-of-production basis and is determined by deducting royalties, operating and transportation expenses from liquids and natural gas sales, after adjusting for realized commodity financial derivative instrument gains or losses.

Funds flow netback reflects funds flow on a per-unit-of-production basis and is determined by dividing funds flow by total production on a per-boe basis. Funds flow netback can also be determined by deducting G&A, transaction costs and cash financing expenses and adding financing income on a per-unit-of-production basis from the operating netback. Refer to "Financial and Operating Results" section above for further details.

Operating netback and funds flow netback are common metrics used in the oil and natural gas industry and are used by Company management to measure operating results on a per boe basis to better analyze and compare performance against prior periods, as well as formulate comparisons against peers.

Adjusted EBITDA and adjusted EBIT

Adjusted EBITDA is calculated as profit or loss before interest, income taxes, depletion, depreciation and amortization, adjusted for certain non-cash and extraordinary items primarily relating to unrealized gains and losses on financial instruments. Adjusted EBITDA is used to calculate CROIC. Adjusted EBIT is calculated as adjusted EBITDA less depletion and depreciation. Adjusted EBIT is used to calculate ROCE. Also refer to "Liquidity and Capital Resources" above for further details.

Net debt and adjusted working capital

Net debt is defined as long-term debt plus adjusted working capital deficit. Adjusted working capital is comprised of current assets less current liabilities on the Company's consolidated statement of financial position and excludes the current portion of financial derivative instruments and the current portion of lease liabilities.

The following table shows the calculation of net debt:

($ thousands)	As at September 30, 2019	2018 (1)
	$	$
Long-term debt	**156,983**	52,187
Adjusted working capital deficit (surplus)	**(12,657)**	(10,332)
Net debt	**144,326**	41,855
Lease liabilities	**2,868**	-
Net debt, including lease liabilities	**147,194**	41,855

(1) IFRS 16, *Leases*, was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. See "Critical Accounting Judgments, Estimates and Policies".

CROIC and ROCE

CROIC is determined by dividing adjusted EBITDA by the average gross carrying value of the Company's oil and gas assets. For the purposes of the CROIC calculation, the average carrying value of the Company's exploration and evaluation, and property and equipment assets, as taken from the Company's consolidated statement of financial position, and excludes accumulated depletion and depreciation.

ROCE is determined by dividing adjusted EBIT by the average carrying value of the Company's net assets. For the purposes for the ROCE calculation, net assets are defined as total assets on the Company's consolidated statement of financial position less current liabilities.

CROIC and ROCE allow management and others to evaluate the Company's capital spending efficiency and ability to generate profitable returns by measuring profit or loss relative to the capital employed in the business. Also refer to "Liquidity and Capital Resources" above for additional information.

Adjusted working capital and available funding

Available funding is comprised of adjusted working capital and undrawn portions of the Company's Credit Facility. Adjusted working capital is comprised of current assets less current liabilities on the Company's consolidated statement of financial position and excludes the current portion of financial derivative instruments and lease liabilities. The available funding measure allows management and others to evaluate the Company's short-term liquidity. Also refer to "Liquidity and Capital Resources" above for additional information.

Initial Production Rates and Short-Term Test Rates

This document may disclose test rates of production for certain wells over short periods of time, which are preliminary and not determinative of the rates at which those or any other wells will commence production and thereafter decline. Short-term test rates are not necessarily indicative of long-term well or reservoir performance or of ultimate recovery. Although such rates are useful in confirming the presence of hydrocarbons, they are preliminary in nature, are subject to a high degree of predictive uncertainty as a result of limited data availability, and may not be representative of stabilized on-stream production rates.

Production over a longer period will also experience natural decline rates, which can be high in the Montney play and may not be consistent over the longer term with the decline experienced over an initial production period. Initial production or test rates may also include recovered "load" fluids used in well completion stimulation operations. Actual results will differ from those realized during an initial production period or short-term test period, and the difference may be material.

Basis of Barrel of Oil Equivalent

Petroleum and natural gas reserves and production volumes are stated as a "barrel of oil equivalent" (boe), derived by converting natural gas to oil equivalency in the ratio of 6,000 cubic feet of gas to one barrel of oil. Readers are cautioned that boe figures may be misleading, particularly if used in isolation. A boe conversion ratio of 6,000 cubic feet of gas to one barrel of oil is based on energy equivalency, which is primarily applicable at the burner tip, and does not represent a value equivalency at the wellhead.

Risk Factors

The acquisition, exploration and development of crude oil, condensate, other NGL and natural gas properties and the production, transportation and marketing of crude oil, condensate, other NGL and natural gas involves many risks, which may influence the ultimate success of the Company. While the management team of Pipestone Energy realizes these risks cannot be eliminated, it is are committed to monitoring and mitigating these risks. These risks include, but are not limited to the following:

- Volatility in market prices and demand for crude oil, condensate, other NGL and natural gas and hedging activities related thereto;
- General economic, business and industry conditions;
- Variance of the Company's actual capital costs, operating costs, depreciation and the economic returns from those anticipated;
- The ability to find, develop or acquire additional reserves and the availability of the capital or financing necessary to do so on satisfactory risk adjusted terms and with the required degree of flexibility;
- The ability to accurately assess available funding to generate the necessary free cashflow and liquidity;
- Risks related to the exploration, development and production of liquids and natural gas reserves and resources;
- Negative public perception of liquids and natural gas development and transportation, hydraulic fracturing and fossil fuels;
- Reassessment by taxing authorities of the Company's prior transactions and filings;
- Actions by provincial or federal governmental authorities, including changes in government regulation, royalties and taxation;
- Management of the Company's growth;
- The ability to identify and make attractive acquisitions, joint ventures or investments, or successfully integrate the Corporate Acquisition and any other future acquisitions or businesses;
- The availability, increased cost or shortage of drilling rigs, hydraulic fracturing equipment, other critical equipment, raw materials, supplies or qualified personnel to execute the Company's development plans;
- Adoption or modification of climate change legislation by governments;
- The ability to attract and retain top talent and key employees;
- Uncertainty associated with estimates of condensate and crude oil, NGL and natural gas reserves and resources and the variance of such estimates from actual future production;
- Dependence upon third-party owned compressors, gathering lines, pipelines and other facilities, certain of which the Company does not control;
- Reliance on third parties for processing and transportation capabilities;
- The ability to satisfy obligations under the Company's firm commitment processing and transportation arrangements;
- The uncertainties related to the Company's identified drilling locations and the high-risk nature of successfully stimulating well productivity and drilling for and producing liquids and natural gas;
- Operating hazards and uninsured risks including the specific risks of fires, floods and natural disasters;
- The Company's drilling activities will encounter H_2S-containing or otherwise known as "sour" gas and the proper safe handling of it;
- The concentration of the Company's assets in the liquids-rich Pipestone Montney area;
- Unforeseen title defects;
- Potential for claims by indigenous peoples or local area residents;
- Failure to accurately estimate the amount or timing of abandonment and reclamation costs;
- Horizontal drilling and applied completion technique risks and failure of drilling results to meet expectations for reserves or production or achieve the targeted returns;
- Expiry of certain leases for the undeveloped leasehold acreage in the future;
- Alternatives to and changing demand for petroleum products particularly condensate;
- Third-party credit risk;
- Risks relating to commodity price hedging instruments;
- Cyber security risks, loss of information and computer systems;
- The potential for security deposits to be required under provincial liability management programs;

- Variations in foreign exchange rates and interest rates;
- Sufficiency of insurance policies; and
- Potential for litigation and costs of current litigation.

Forward-Looking Statements

This document contains certain forward-looking statements. Forward-looking statements are subject to known and unknown risks, uncertainties and other factors that could influence actual results or events and cause them to differ materially from those stated, anticipated or implied. Forward-looking statements necessarily involve risks including, without limitation, those associated with liquids and natural gas exploration, development, production, marketing and transportation, such as dry holes and non-commercial wells, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, production declines, health, safety and environmental risks, competition from other producers and the ability to access sufficient capital from internal and external sources. Forward-looking information may include statements with words such as “anticipate”, “believe”, “expect”, “plan”, “intend”, “estimate”, “propose”, “project”, “scheduled”, or similar words suggesting future outcomes. Readers and prospective investors in the Company’s securities are cautioned not to place undue reliance on forward-looking information as, by its nature, it is based on current expectations regarding future events that involve a number of assumptions, inherent risks and uncertainties, which could cause actual results to differ materially from those anticipated by the Company.

In particular, but without limiting the foregoing, this document contains forward-looking statements pertaining to: the Company’s general strategic plans and growth strategies to generate top decile, full cycle investment returns and exceed cash flow generation hurdles; receipt of funding from Tidewater and timing to commence construction of East Battery; timing to bring Pipestone Energy’s 9-14 pad wells on-stream; drilling plans on Pipestone Energy’s 6-24 pad and 6-30 pad; timing for production from 6-24 pad; capability to generate free cash flow above maintenance requirements; production capacity from infrastructure build-out; timing to release 2020 guidance and expectations of weighting of allocation of capital in 2020; Pipestone Energy’s 2019 capital guidance range; and Pipestone Energy’s 2019 exit production guidance.

With respect to the forward-looking statements contained in this document, Pipestone Energy has assessed material factors and made assumptions regarding, among other things: future commodity prices and currency exchange rates, including consistency of future oil, natural gas liquids (NGLs) and natural gas prices with current commodity price forecasts; the ability to integrate Blackbird’s and Predecessor Pipestone’s historical businesses and operations and realize financial, operational and other synergies from the combination transaction completed on January 4, 2019; Pipestone Energy’s continued ability to obtain qualified staff and equipment in a timely and cost-efficient manner; the predictability of future results based on past and current experience; the predictability and consistency of the legislative and regulatory regime governing royalties, taxes, environmental matters and oil and gas operations, both provincially and federally; Pipestone Energy’s ability to successfully market its production of oil, NGLs and natural gas; the timing and success of drilling and completion activities (and the extent to which the results thereof meet expectations); Pipestone Energy’s future production levels and amount of future capital investment, and their consistency with Pipestone Energy’s current development plans and budget; future capital expenditure requirements and the sufficiency thereof to achieve Pipestone Energy’s objectives; the successful application of drilling and completion technology and processes; the applicability of new technologies for recovery and production of Pipestone Energy’s reserves and other resources, and their ability to improve capital and operational efficiencies in the future; the recoverability of Pipestone Energy's reserves and other resources; Pipestone Energy’s ability to economically produce oil and gas from its properties and the timing and cost to do so; the performance of both new and existing wells; future cash flows from production; future sources of funding for Pipestone Energy’s capital program, and its ability to obtain external financing when required and on acceptable terms; future debt levels; geological and engineering estimates in respect of Pipestone Energy’s reserves and other resources; the accuracy of geological and geophysical data and the interpretation thereof; the geography of the areas in which Pipestone Energy conducts exploration and development activities; the timely receipt of required regulatory approvals; the access, economic, regulatory and physical limitations to which Pipestone Energy may be subject from time to time; and the impact of industry competition.

The forward-looking statements contained herein reflect management's current views, but the assessments and assumptions upon which they are based may prove to be incorrect. Although Pipestone Energy believes that its underlying assessments and assumptions are reasonable based on currently available information, undue reliance should not be placed on forward-looking statements, which are inherently uncertain, depend upon the accuracy of such assessments and assumptions, and are subject to known and unknown risks, uncertainties and other factors, both general and specific, many of which are beyond Pipestone Energy's control, that may cause actual results or events to differ materially from those indicated or suggested in the forward-looking statements. Such risks and uncertainties include, but are not limited to, volatility in market prices and demand for oil, NGLs and natural gas and hedging activities related thereto; the ability to successfully integrate Blackbird's and Predecessor Pipestone's historical businesses and operations; general economic, business and industry conditions; variance of Pipestone Energy's actual capital costs, operating costs and economic returns from those anticipated; the ability to find, develop or acquire additional reserves and the availability of the capital or financing necessary to do so on satisfactory terms; and risks related to the exploration, development and production of oil and natural gas reserves and resources. Additional risks, uncertainties and other factors are discussed under the heading "Risk Factors" and in Blackbird's management information circular dated November 21, 2018, a copy of which is available electronically on Pipestone Energy's SEDAR at www.sedar.com.

The forward-looking statements contained in this document are made as of the date hereof and Pipestone Energy assumes no obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, unless required by applicable securities laws. All forward-looking statements herein are expressly qualified by this advisory.

Abbreviations

The following summarizes the abbreviations used in this document:

Condensate and Crude Oil, and Natural Gas Liquids	
bbl	barrel
Mbbl	thousand barrels
bbls/d	barrels per day
boe	barrel of oil equivalent
Mboe	thousand barrels of oil equivalent
boe/d	barrel of oil equivalent per day
NGL	natural gas liquids, consisting of ethane (C_2), propane (C_3) and butane (C_4)
Bbls/MMcf	barrels per million cubic feet
CGR	Condensate-gas ratio. Measures the liquid content of the hydrocarbon mixture
condensate	Pentanes plus (C_5+) separated at the field level and C_5+ separated from the NGL mix at the facility level

Natural Gas	
Mcf	thousand cubic feet
MMcf	million cubic feet
Mcf/d	thousand cubic feet per day
GJ	Gigajoule; 1 Mcf of natural gas is about 1.05 GJ
MMBtu	million British thermal units; 1 GJ is about 0.95 MMBtu

Other Abbreviations	
$000s	thousands of dollars
Adjusted working capital	working capital (current assets less current liabilities), excluding financial derivative instruments and lease liabilities
AECO	the AECO Hub, a natural gas storage facility located in Suffield and Countess, Alberta, part of the NOVA Pipeline System
Alliance Chicago Exchange Hub	a market hub for natural gas transported on the Alliance Pipeline to be purchased and sold between entities
Alliance Pipeline	a natural gas pipeline running from northeastern British Columbia to Illinois, in the United States
C$	Canadian dollars
Chicago City Gate	Chicago Index Futures natural gas price
CNOR LP	Canadian Non-Operated Resources LP
collar	a risk-management strategy employed by the Company in which an out-of-the-money put option is purchased, while simultaneously writing an out-of-the-money call option. Collars are entered into at no cost (the cost of the put is offset by the proceeds of the call). Collars allow the Company to receive the price of the commodity between the collar range. The downside price protection is at the cost of limiting the potential upside price
CROIC	cash return on invested capital
D&D	depletion and depreciation
EBIT	earnings before interest and taxes
EBITDA	earnings before interest, taxes, depreciation and amortization
EdCon	Edmonton Condensate
Enbridge	Enbridge Inc. and its affiliates
G&A	general and administrative
GAAP	Generally accepted accounting principles
IAS	International Accounting Standard
IASB	International Accounting Standards Board
IFRIC	International Financial Reporting Interpretations Committee
IFRS	International Financial Reporting Standards
IFRS 16	International Financial Reporting Standards 16, *Leases*
Keyera	Keyera Corp. and its affiliates
LNG	liquified natural gas
NE	Northeast
Net Debt	long-term debt less adjusted working capital
NGTL	Nova Gas Transmission Ltd. Refers to a natural gas gathering system for the Western Canadian Sedimentary Basin
NMN	Not meaningful number
NW	Northwest
NYMEX	New York Mercantile Exchange
Pembina	Pembina Pipeline Corporation and its affiliates

Other Abbreviations	
PSU	performance share unit
Q1	first quarter ended March 31st
Q2	second quarter ended June 30th
Q3	third quarter ended September 30th
Q4	fourth quarter ended December 31st
ROCE	return on capital employed
ROU	right-of-use
RSU	restricted share unit
SE	Southeast
SW	Southwest
swap	over-the-counter contracts relating to interest rates, foreign exchange, or commodities. Entered into by the Company to reduce variability and manage risk via fixing that variable
TCPL	TC Pipelines Limited
Tidewater	Tidewater Midstream and Infrastructure Ltd. and its affiliates
TSX	Toronto Stock Exchange
US$	United States dollars
WTI	West Texas Intermediate
XLE	extreme limited entry
YTD	year-to-date

Corporate Information

BOARD OF DIRECTORS

GORDON RITCHIE, CHAIR (1)(2)

GARTH BRAUN (2)

WILLIAM LANCASTER (1)(3)

JOHN ROSSALL (1)(2)(3)

GEETA SANKAPPANAVAR (3)

ROBERT TICHIO (2)

PAUL WANKLYN

Notes:
(1) Audit Committee
(2) Compensation and Governance Committee
(3) Reserves and HSE Committee

MANAGEMENT

PAUL WANKLYN
President & Chief Executive Officer

DUSTIN HOFFMAN
Chief Operating Officer

CRAIG NIEBOER
Chief Financial Officer

DARCY ERICKSON
Vice President, Operations & Production

DAN VAN KESSEL
Vice President, Corporate Development

NEAL ROSS
Corporate Secretary

HEAD OFFICE
Suite 3700, 888 – 3rd Street S.W.
Calgary, Alberta
T2P 5C5

Telephone: 587.392.8411

AUDITORS
KPMG LLP
Calgary, Alberta

BANKERS
National Bank of Canada
Bank of Montreal

EVALUATION ENGINEERS
McDaniel & Associates Consultants Ltd.
Calgary, Alberta

LEGAL COUNSEL
Osler, Hoskin & Harcourt LLP
Calgary, Alberta

TRANSFER AGENT
Computershare Limited
Calgary, Alberta

STOCK EXCHANGE LISTING
TSX Venture Exchange
Symbol: PIPE