Q3 2018 HIGHLIGHTS

- Achieved record quarterly average production of 1150 boe/d (96% oil), a 69% increase over the third quarter of 2017.
- Increased revenue by 114% to a record $5.9 million, compared to $2.7 million for the third quarter of 2017.
- Generated operating field netback of $3.2 million ($0.04/share), an increase of 175% over the third quarter of 2017.
- Generated funds flow from operations of $1.4 million ($0.02/share), an increase of 111% over the third quarter of 2017.
- Increased operating netbacks, including losses on commodity contracts, to $23.43/boe, an increase of 22% over the third quarter of 2017.
- Completed successful eleven-well summer drilling program and finished battery upgrades at the Atlee Buffalo F pool facility.
- Achieved a Corporate Liability Management Ratio ("LMR") with the Alberta Energy Regulator ("AER") of 7.05 at the end of the third quarter 2018, which is within the top 12% of all licensees evaluated.

CORPORATE UPDATE

Since securing a five year term loan in September 2017, Hemisphere has drilled 20 new wells in the Atlee Buffalo area including 14 wells drilled in 2018. Of these, five wells have been converted to water injectors, and are either now injecting or have recently obtained injection approval from the AER. Based on field estimates, production over the first half of November was approximately 1500 boe/d (97% oil), which is more than double the production as compared to Hemisphere's average daily production during the third quarter of 2017.

With the price of Canadian crude oil dropping dramatically in recent weeks, Hemisphere is heavily focused on reducing operating costs, including those associated with optimization projects that could increase production further. Hemisphere will instead focus in the near-term on augmenting water injection in order to continue to re-energize the reservoirs and minimizing costs associated with winter weather conditions.

Hemisphere remains financially flexible with additional room to borrow within its US$35 million term loan limit. However, at this time management has delayed any further capital activity until commodity prices improve. Additionally, in response to historically wide Canadian crude oil differentials, the Company has proactively entered into an agreement with its lender to temporarily waive the application of and compliance with its two financial covenants (being the interest coverage ratio and total leverage ratio covenants) and two reserve-based covenants (being the PDP coverage ratio and total proved reserve coverage ratio covenants) that are included in the credit agreement with the lender, in each case for the fiscal quarter ending December 31, 2018.

With continued success of its waterflood projects, the Company expects to see sustained increases in production and reserves as water is continually swept through these reservoirs, even without any additional capital spending at this time. Management believes the Company has considerable growth upside through development of its exceptional oil assets and will plan accordingly through 2019 as Canadian crude prices are projected to improve.

Q3 2018 FINANCIAL AND OPERATING HIGHLIGHT

	Three Months Ended September 30		Nine Months Ended September 30	
	2018	2017	**2018**	2017
OPERATING				
Average daily production				
Oil (bbl/d)	**1,106**	644	**977**	574
Natural gas (Mcf/d)	**255**	217	**257**	274
NGL (bbl/d)	**1**	1	**2**	2
Combined (boe/d)	**1,150**	681	**1,021**	622
Oil and NGL weighting	**96%**	95%	**96%**	93%
Average sales prices				
Oil ($/bbl)	**$ 57.19**	$ 45.58	**$ 55.26**	$ 46.20
Natural gas ($/Mcf)	**1.31**	1.48	**1.55**	2.42
NGL ($/bbl)	**56.09**	42.62	**57.55**	45.41
Combined ($/boe)	**$ 55.36**	$ 43.62	**$ 53.33**	$ 43.87
Operating netback ($/boe)				
Petroleum and natural gas revenue	**$ 55.36**	$ 43.62	**$ 53.33**	$ 43.87
Royalties	**11.22**	9.36	**9.67**	7.53
Operating costs	**11.06**	12.78	**12.17**	15.31
Transportation costs	**2.47**	2.71	**2.67**	2.85
Operating field netback(1)	**30.62**	18.77	**28.83**	18.18
Realized commodity hedging (gain) loss	**7.19**	0.51	**8.15**	1.05
Operating netback(2)	**$ 23.43**	$ 19.28	**$ 20.67**	$ 19.22
FINANCIAL				
Petroleum and natural gas revenue	**$ 5,856,762**	$ 2,733,656	**$ 14,869,598**	$ 7,446,068
Operating field netback(1)	**3,239,216**	1,176,204	**8,037,033**	3,084,709
Operating netback(2)	**2,478,636**	1,208,106	**5,763,569**	3,262,794
Funds flow from operations(3)	**1,387,469**	657,840	**2,738,280**	1,761,249
Per share, basic and diluted	**0.02**	0.01	**0.03**	0.02
Net income (loss)	**(236,344)**	(142,254)	**(4,878,900)**	(487,655)
Per share, basic and diluted	**(0.00)**	(0.00)	**(0.05)**	(0.01)
Capital expenditures	**9,185,092**	3,107,979	**14,588,032**	4,025,800
Net debt(4)	**31,207,369**	14,426,091	**31,207,369**	14,426,091
Term Loan(5)	**$ 28,241,400**	$ 11,589,132	**$ 28,241,400**	$ 11,589,132

Notes:

(1) Operating field netback is a non-IFRS measure calculated as the Company's oil and gas sales, less royalties, operating expenses and transportation costs on an absolute and per barrel of oil equivalent basis.

(2) Operating netback is a non-IFRS measure calculated as the operating field netback plus the Company's realized commodity hedging gain (loss) on an absolute and per barrel of oil equivalent basis.

(3) Funds flow from operations is a non-IFRS measure that represents cash generated by operating activities, before changes in non-cash working capital and may not be comparable to measures used by other companies.

(4) Net debt is a non-IFRS measure calculated as current assets minus current liabilities including term loan or bank indebtedness and excluding fair value of financial instruments and any flow-through share premium.

(5) Gross term loan amount including foreign exchange

	Three Months Ended September 30		Nine Months Ended September 30	
	2018	2017	**2018**	2017
SHARE CAPITAL				
Common shares outstanding	**89,793,302**	89,793,302	**89,793,302**	89,793,302
Stock options outstanding	**8,419,000**	8,019,000	**8,419,000**	8,019,000
Warrants outstanding	**13,750,000**	13,750,000	**13,750,000**	13,750,000
Fully Diluted	**111,962,302**	111,562,302	**111,962,302**	111,562,302
Weighted-average shares outstanding – basic and diluted	**89,793,302**	86,977,163	**89,793,302**	87,480,045

MANAGEMENT'S DISCUSSION AND ANALYSIS

Dated as at November 21, 2018

The following Management's Discussion and Analysis ("MD&A") is a review of the operations and current financial position for the three and nine months ended September 30, 2018 for Hemisphere Energy Corporation ("Hemisphere" or the "Company") and should be read in conjunction with the unaudited interim condensed financial statements and related notes for the three and nine months ended September 30, 2018, and the audited annual financial statements and related notes for the year ended December 31, 2017. These documents and additional information relating to the Company, including the Company's Annual Information Form, are available on SEDAR at www.sedar.com or the Company's website at www.hemisphereenergy.ca.

The information in this MD&A is based on the unaudited interim condensed financial statements which were prepared in accordance with International Financial Reporting Standards ("IFRS") applicable to the preparation of unaudited interim condensed financial statements including IAS 34 "Interim Financial Reporting", as issued by the International Accounting Standards Board ("IASB").

This MD&A contains non-IFRS measures, additional IFRS measures and forward-looking statements. Readers are cautioned that this document should be read in conjunction with Hemisphere's disclosure under "Non-IFRS and additional IFRS Measures" and "Forward-Looking Statements" included at the end of this MD&A. All figures are in Canadian dollars unless otherwise noted.

Business Overview

Hemisphere produces oil and natural gas from its Jenner and Atlee Buffalo properties in southeast Alberta. The Company is headquartered in Vancouver, British Columbia and is traded on the TSX Venture Exchange under the symbol "HME".

Jenner, Alberta

Hemisphere has a 100% working interest in its owned and operated wells in Jenner with ownership in 19,650 net acres and has continued to build a land position in the Jenner area through Crown land sales and strategic acquisitions. The property is accessible year-round and is located east of Brooks in southeastern Alberta.

Atlee Buffalo, Alberta

The Company operates 100% of its wells in the Atlee Buffalo area. The property is accessible year-round and is located 30 kilometres east of the Company's Jenner property in southeastern Alberta. Hemisphere has a 100% working interest in 14,880 net acres and has been building a land position in Atlee Buffalo through Crown land sales and strategic acquisitions since 2013.

Operating Results

The Company generated funds flow from operations of $1,387,468 ($0.02/share) during the third quarter of 2018, as compared to funds flow from operations of $657,840 ($0.01/share) during the third quarter of 2017. Funds flow for the nine months ended September 30, 2018 increased to $2,738,280 ($0.03/share) from $1,761,249 ($0.02/share) for the same period in 2017. These improvements are due primarily to the Company's increased revenues, from increases in production rates and commodity prices. Funds flow gains are somewhat offset by the $760,580 and $2,273,464 losses from hedging contracts for the three and nine months ended September 30, 2018 respectively. These hedge contracts are mostly a requirement of the five year term loan secured by the Company for the development of its future assets.

For the three and nine months ended September 30, 2018, the Company reported net losses of $236,344 ($0.00/share) and $4,878,900 ($0.05/share), respectively, compared to net losses of $142,254 ($0.00/share) and $487,655 ($0.01/share) for the three and nine months ended September 30, 2017, respectively. The higher losses during the comparable nine months ended September 30, 2018 are primarily attributed to the increases in hedging losses, finance expense and foreign exchange loss, in the amounts of $5,587,344, $2,267,376 and $386,015 respectively.

Production

	Three Months Ended September 30		Nine Months Ended September 30	
By product:	**2018**	2017	**2018**	2017
Oil (bbl/d)	**1,106**	644	**977**	574
Natural gas (Mcf/d)	**255**	217	**257**	274
NGL (bbl/d)	**1**	1	**2**	2
Total (boe/d)	**1,150**	681	**1,021**	622
Oil and NGL weighting	**96%**	95%	**96%**	93%

In the third quarter of 2018, the Company's average daily production was 1,150 boe/d (96% oil and NGL) representing a 69% increase over the comparable quarter in 2017. For the nine months ended September 30,2018, the Company's average daily production was 1,021 boe/d (96% oil and NGL), representing a 64% increase from 622 boe/d (93% oil and NGL) for the same period in 2017.
This increase in production can be attributed to new wells drilled and placed on production between September 2017 and September 2018, as well as the continued success and improvement of the base waterflood performance in the Upper Mannville F and G pools.

Average Benchmark and Realized Prices

	Three Months Ended September 30		Nine Months Ended September 30	
	2018	2017	**2018**	2017
Benchmark prices				
WTI ($US/bbl)(1)	**$ 69.46**	$ 48.20	**$ 66.74**	$ 49.46
Exchange rate (1 $US/$C)	**1.3070**	1.2529	**1.2872**	1.3233
WTI ($C/bbl)	**90.79**	60.39	**85.90**	68.68
WCS ($C/bbl)(2)	**61.78**	47.93	**57.78**	49.40
AECO natural gas ($/Mcf)(3)	**1.28**	1.61	**1.51**	2.69
Average realized prices				
Crude oil ($/bbl)	**57.19**	45.58	**55.26**	46.20
Natural gas ($/Mcf)	**1.31**	1.48	**1.55**	2.42
NGL ($/bbl)	**56.09**	42.62	**57.55**	45.42
Combined ($/boe)	**$ 55.36**	$ 43.62	**$ 53.33**	$ 43.87

Notes:
(1) Represents posting prices of West Texas Intermediate Oil.
(2) Represents posting prices of Western Canadian Select.
(3) Represents the Alberta 30 day spot AECO posting prices.

The Company's oil and natural gas sales and financial results are significantly influenced by changes in commodity prices. The West Texas Intermediate pricing ("WTI") at Cushing, Oklahoma is the benchmark reference price for North American crude oil prices. Canadian oil prices, including Hemisphere's crude oil, are based on price postings, which is WTI-adjusted for transportation, quality and the currency conversion rates from United States dollar ("USD") to Canadian dollar.

The Company's combined average realized price increased by 27% from $43.62/boe during the three months ended September 30, 2017 to $55.36/boe during three months ended September 30, 2018. The Company's combined average realized price increased by 22% from $43.87/boe during the nine months ended September 30, 2017 to $53.33/boe during nine months ended September 30, 2018. These increases are the result of higher oil prices during the three and nine months ended September 30, 2018 which are reflected in the respective $11.61/bbl and $9.06/bbl increases from the Company's average realized crude oil price during the same periods in 2017.

The Company's average realized natural gas price decreased in the three and nine months ended September 30, 2018 by $0.17/Mcf and $0.87/Mcf, respectively, over the comparable periods in 2017.

At September 30, 2018, the Company held derivative commodity contracts as follows:

Product	Type	Volume	Price	Index	Term
Crude oil	Swap	300 bbl/d	US$50.67	WTI-NYMEX	January 1, 2018 – December 31, 2018
Crude oil	Swaption	150 bbl/d	US$54.65	WTI-NYMEX	July 1, 2018 – February 28, 2019
Crude oil	Swap	250 bbl/d	US$50.67	WTI-NYMEX	January 1, 2019 – December 31, 2019
Crude oil	Collar	130 bbl/d	US$40.00-US$74.50	WTI-NYMEX	March 1, 2019 – December 31, 2019
Crude oil	Swap	200 bbl/d	US$50.67	WTI-NYMEX	January 1, 2020 – August 31, 2020
Crude oil	Collar	120 bbl/d	US$40.00-US$68.25	WTI-NYMEX	January 1, 2020 – December 31, 2020
Crude oil	Collar	200 bbl/d	US$40.00-US$67.05	WTI-NYMEX	September 1, 2020 – December 31, 2020
Crude oil	Collar	275 bbl/d	US$40.00-US$65.50	WTI-NYMEX	January 1, 2021 – March 31, 2021

At September 30, 2018 the commodity contracts were fair valued as a liability of $5,737,162 recorded on the balance sheet, and an unrealized loss for the three and nine month periods of $721,244 and $3,313,880 respectively (September 30, 2017 – gains of $48,919 and $221,129 respectively).

Revenue

	Three Months Ended September 30		Nine Months Ended September 30	
	2018	2017	**2018**	2017
Oil	**$ 5,820,348**	$ 2,698,497	**$ 14,737,045**	$ 7,245,314
Natural gas	**30,662**	29,473	**108,471**	180,948
NGL	**5,752**	5,686	**24,082**	19,806
Total	**$ 5,856,762**	$ 2,733,656	**$ 14,869,598**	$ 7,446,068

Revenue for the three and nine months ended September 30, 2018 increased by 114% and 100%, respectively, from the comparable periods in 2017. These increases are attributed to the $11.74/boe and $9.46/boe increases in the Company's combined average realized prices, and increases in production by 69% and 64% during the periods, respectively.

Operating Netback

	Three Months Ended September 30		Nine Months Ended September 30	
	2018	2017	**2018**	2017
Operating netback				
Revenue	**$ 5,856,762**	$ 2,733,656	**$ 14,869.598**	$ 7,446,068
Royalties	**1,186,777**	586,468	**2,696,740**	1,278,205
Operating costs	**1,169,758**	801,017	**3,392,242**	2,598,837
Transportation costs	**261,011**	169,968	**743,583**	484,317
Operating field netback(1)	**$ 3,239,216**	$ 1,176,204	**$ 8,037,033**	$ 3,084,709
Realized commodity hedging (gain) loss	**760,580**	(31,902)	**2,273,464**	(178,085)
Operating netback(2)	**$ 2,478,636**	$ 1,208,106	**$ 5,763,569**	$ 3,262,794
Operating netback ($/boe)				
Revenue	**$ 55.36**	$ 43.62	**$ 53.33**	$ 43.87
Royalties	**11.22**	9.36	**9.67**	7.53
Operating costs	**$ 11.06**	$ 12.78	**$ 12.17**	$ 15.31
Transportation costs	**2.47**	$ 2.71	**2.67**	$ 2.85
Operating field netback(1)	**$ 30.62**	$ 18.77	**$ 28.83**	$ 18.18
Realized commodity hedging (gain) loss	**7.19**	(0.51)	**8.15**	(1.05)
Operating Netback(2)	**$ 23.43**	$ 19.28	**$ 20.67**	$ 19.22

Notes:

(1) Operating field netback is a non-IFRS measure calculated as the Company's oil and gas sales, less royalties, operating expenses and transportation costs on an absolute and per barrel of oil equivalent.

(2) Operating netback is a non-IFRS measure calculated as the operating field netback plus the Company's realized commodity hedging gain (loss) on an absolute and per barrel of oil equivalent.

Royalties for the three months ended September 30, 2018 were $11.22/boe, representing a 20% increase from the three months ended September 30, 2017. Royalties for the nine months ended September 30, 2018 were $9.67/boe, representing a 28% increase from the same period in 2017. This was a result of higher oil prices which directly impact the Crown royalty par price, higher average oil rates per well as waterflood continues to improve performance, and the end of royalty holiday period for some high rate producers.

Operating costs include all costs for gathering, processing, dehydration, compression, water processing and marketing of the oil, natural gas and NGLs, as well as additional costs incurred periodically for maintenance and repairs. Operating costs for the three and nine months ended September 30, 2018 increased on an absolute basis by 46% and 31%, respectively, but decreased on a per boe basis by $1.72 and $3.15, respectively, over the same periods in 2017.

The increase to absolute operating costs is the result of more production and associated operating wellbores, while the decrease per boe is due to efficiencies from the higher production.

Transportation costs include all costs incurred to transport emulsion and oil and gas sales to processing and distribution facilities. Transportation costs were $2.47/boe during the third quarter of 2018, which is a $0.25/boe decrease from the comparable quarter in 2017. Transportation costs were $2.67/boe for the nine months ended September 30, 2018, which represents a $0.19/boe decrease from the same period in 2017. The company's installation of handling facilities led to a reduction in trucked water, resulting in a decrease in trucking for the three and nine months ended September 30, 2018 over the comparable periods in 2017.

Operating netback at $23.43/boe for the three months ended September 30, 2018 was 22% higher than the comparable quarter in 2017, mainly due to the 27% increase in the Company's combined average realized price and higher production rates for the period, as discussed above. For the nine months ended September 30, 2018 operating netback was $20.67/boe, just 8% higher than the same period in 2017. This increase is primarily attributable to a net $9.20 increase in hedging losses for the nine months ending September 30, 2018, compared to the same period of 2017.

Exploration and Evaluation

Exploration and evaluation expense generally consists of certain geological and geophysical costs, expiry of undeveloped lands, and costs of uneconomic exploratory wells. Exploration and evaluation expenses for the three months ended September 30, 2018 and 2017 were $10,533 and $9,295, respectively. For the nine months ended September 30, 2018 and 2017, exploration and evaluation expenses were $36,074 and $33,585, respectively.

Depletion and Depreciation

	Three Months Ended S 30		Nine Months Ended S 30	
	2018	2017	**2018**	2017
Depletion expense	**$ 1,297,111**	$ 851,854	**$ 3,186,452**	$ 2,247,860
Depreciation expense	**1,371**	1,845	**4,110**	5,533
Total	**$ 1,298,482**	$ 853,699	**$ 3,190,562**	$ 2,253,393
$ per boe	**$ 12.27**	$ 13.62	**$ 11.44**	$ 13.28

The depletion rate is calculated using the unit-of-production method on Proved and Probable oil and natural gas reserves, taking into account the future development costs ("FDC") to develop and produce undeveloped and non-producing reserves.

Depletion and depreciation expenses for the three months ended September 30, 2018 decreased to $12.27/boe from $13.62/boe for the same period in 2017. For the nine months ended September 30, 2018, depletion and depreciation expenses decreased to $11.44/boe from $13.28/boe for the same period in 2017. The decrease in depletion expense for the periods ended September 30, 2018 as compared to the same periods in 2017 is due to amortization of production over a larger reserve base from the Company's December 31, 2017 independent engineers evaluation report as prepared by McDaniel and Associates Consultants Ltd.

Capital Expenditures

	Three Months Ended September 30		Nine Months Ended September 30	
	2018	2017	**2018**	2017
Land and lease	**$ 18,185**	$ 12,096	**$ 23,215**	$ 24,800
Geological and geophysical	**28,153**	12,229	**272,355**	165,878
Drilling and completions	**6,611,383**	2,294,155	**10,877,600**	2,453,732
Facilities and infrastructure	**2,527,370**	789,498	**3,414,862**	1,381,389
Total capital expenditures(1)	**$ 9,185,092**	$ 3,107,979	**$ 14,588,032**	$ 4,025,800

Note:
(1) Total capital expenditures exclude decommissioning obligations and non-cash items.

The development capital spent during the nine months ended September 30, 2018 included capital associated with drilling and completing three new wells in the spring and eleven wells in the summer of 2018.

General and Administrative

	Three Months Ended September 30		Nine Months Ended September 30	
	2018	2017	**2018**	2017
Gross general and administrative	**$ 563,987**	$ 456,723	**$ 1,688,158**	$ 1,281,345
Capitalized general and administrative	**(186,886)**	(89,649)	**(414,546)**	(249,052)
Total	**$ 377,101**	$ 367,074	**$ 1,273,612**	$ 1,032,293
$ per boe	**$ 3.56**	$ 5.86	**$ 4.57**	$ 6.08

Gross general and administrative expenses per boe for the three and nine months ended September 30, 2018 decreased by 39% and 25% respectively, over the same periods in 2017 due to production growth of the company. On an absolute basis, these expenses increased by $107,263 and $406,813 respectively, over the same quarterly and year to date periods in 2017, due to increased activities resulting in higher consulting fees and salaries.

The Company capitalizes some general and administrative expenses which can be attributed to any costs incurred during the period relating to its development and exploration activities. For the three and nine months ended September 30, 2018, capitalized general and administrative expenses increased by $97,237 and $165,494 respectively, over the comparable periods in 2017.

Share-based Payments

Share-based payments are non-cash expenses which reflect the estimated value of stock options issued to directors, employees and consultants of the Company. For the three and nine months ended September 30, 2018, the Company recorded total share-based payments of $56,854 and $174,952 respectively, compared to $214,388 and $215,480 for the same periods in 2017.

The Company uses a Black-Scholes option pricing model to calculate the fair value of stock option grants where the corresponding expense is recognized over the option vesting period. While no stock options were granted in the third quarter of 2018, $56,854 of options vested regarding grants issued in prior fiscal periods.

	Three Months Ended September 30		Nine Months Ended September 30	
	2018	2017	**2018**	2017
Share-based payments	**$ 56,854**	$ 214,387	**$ 174,952**	$ 215,480
Capitalized costs	**31,433**	94,670	**101,613**	94,670
Total share-based payments	**$ 88,287**	$ 309,058	**$ 276,565**	$ 310,150

Finance Expense

	Three Months Ended September 30		Nine Months Ended September 30	
	2018	2017	**2018**	2017
Interest expense	**$ 707,182**	$ 165,368	**$ 1,789,709**	$ 451,429
Accretion of debt issuance costs	**51,625**	13,800	**148,815**	13,800
Amortization of deferred charges	**76,129**	2,285	**225,094**	2,285
Accretion of decommissioning liabilities	**34,587**	26,932	**103,759**	80,795
Total	**$ 869,523**	$ 208,386	**$ 2,267,377**	$ 548,310
$ per boe	**$ 8.22**	$ 3.33	**$ 8.13**	$ 3.23

Interest expense for the three and nine months ended September 30, 2018 increased by $541,814 and $1,338,280 over the respective periods in 2017. This increase is a result of higher interest incurred on the new term loan secured in September 2017, which carries a higher interest rate and balance than the retired bank credit facility from the comparable period in 2017, as well as amortization of debt issuance costs.

Accretion expense represents the adjusted present value of the Company's decommissioning obligations which include the abandonment and reclamation costs associated with wells and facilities. During the three and nine months ended September 30, 2018 accretion expense increased by 28% over the comparable periods in 2017 due to the additional abandonment and reclamation costs associated with the new wells drilled.

Tax Pools

The Company has approximately $56.3 million (2016 - $48.3 million) of tax pools available to be applied against future income for tax purposes. Based on available pools and current commodity prices, the Company does not expect to pay current income tax in 2018 and any taxes payable beyond 2018 will primarily be a function of commodity prices, capital expenditures and production volumes.

	Deduction Rate	**December 31, 2017**	December 31, 2016
Canadian exploration expense (CEE)	100%	**$ 3,336,823**	$ 3,336,823
Canadian development expense (CDE)	30%	**15,671,786**	14,879,326
Canadian oil and gas property expense (COGPE)	10%	**6,089,111**	6,765,679
Non-capital losses carry forwards (NCL)	100%	**29,648,931**	21,122,443
Undepreciated capital cost (UCC)	20-55%	**1,182,138**	1,571,468
Share issuance costs and other	Various	**340,199**	581,463
Total		**$ 56,268,988**	$ 48,257,202

Summary of Quarterly Results

	2018				2017			
	Sep. 30 Q3[(1)]	Jun. 31 Q2[(2)]	Mar. 31 Q1[(3)]	Dec. 31 Q4[(4)]	Sep. 30 Q3[(5)]	Jun. 30 Q2[(6)]	Mar. 31 Q1[(7)]	Dec. 31 Q4[(8)]
Average daily production (boe/d)	**1,150**	1,053	858	770	681	600	583	590
Petroleum and natural gas revenue	**5,856,762**	5,618,915	3,393,921	3,528,565	2,733,656	2,419,666	2,292,746	2,206,835
Petroleum and natural gas Operating Field Netback[(9)]	**3,239,217**	3,279,840	1,517,979	1,847,185	1,176,204	989,681	958,276	860,849
Funds flow from/used in operations[(10)]	**1,387,470**	1,251,089	99,720	714,801	657,840	598,078	505,331	273,181
Per share, basic and diluted	**0.02**	0.01	0.00	0.01	0.01	0.01	0.01	0.00
Net income (loss)	**(236,344)**	(2,253,163)	(2,389,393)	(3,308,520)	(142,254)	(206,724)	(138,678)	(620,027)
Basic and diluted income (loss) per share	**(0.00)**	(0.03)	(0.03)	(0.04)	(0.00)	(0.00)	(0.00)	(0.01)
Combined average realized price ($/boe)	**55.36**	58.64	43.96	49.80	43.62	44.34	43.68	40.63
Operating netback ($/boe)[(11)]	**23.43**	24.27	12.42	23.29	19.28	20.09	18.26	15.85

Notes:

(1) The increases in revenue and funds flow from operations are due to increases in production rates, while netbacks remained relatively the same due to the decrease in commodity prices.

(2) The increases in revenue, netbacks and funds flow from operations are due to increases in production rates and commodity prices.

(3) The decreases in netbacks and funds flow from operations are primarily due to the wider WCS/WTI differential and losses incurred from hedging contracts.

(4) The increases in revenue, netbacks and funds flow from operations are due to increases in production rates and commodity prices.

(5) The increases in revenue, netbacks and funds flow from operations are due to increases in production rates and commodity prices, as well as the realized commodity hedging gains.

(6) The increases in revenue and netbacks are due to an 8% increase in the Company's combined average realized price and 31% lower general and administrative costs from the previous quarter.

(7) Revenues in this quarter increased as a result of a 14% increase in the Company's production and a 19% increase in the combined average realized price from the third quarter of 2016.

(8) The increases in revenue and netbacks, and the resulting reduced loss in this quarter over the previous quarter is due primarily to a reduction in operating costs as well as an increase in production and a slight improvement in commodity prices..

(9) Operating field netback per boe is a non-IFRS measure calculated as the Company's oil and gas sales, less royalties, operating expenses and transportation costs on an absolute and per barrel of oil equivalent basis.

(10) Funds flow from operations is a non-IFRS measure that represents cash generated by operating activities, before changes in non-cash working capital and may not be comparable to measures used by other companies.

(11) Operating netback is a non-IFRS measure calculated as the operating field netback plus the Company's realized commodity hedging gain (loss) on an absolute and per barrel of oil equivalent basis.

Outstanding Share Capital

	November 21, 2018	**September 30, 2018**	December 31, 2017
Fully diluted share capital			
Common shares issued and outstanding	89,793,302	**89,793,302**	89,793,302
Stock options	8,419,000	**8,419,000**	8,169,000
Warrants	13,750,000	**13,750,000**	13,750,000
Total fully diluted shares outstanding	111,962,302	**111,962,302**	111,712,302

The Company has the following stock options that are outstanding and exercisable as at November 21, 2018:

Exercise Price	Grant Date	Expiry Date	Balance Outstanding November 21, 2018	Balance Exercisable November 21, 2018
$0.24	January 29, 2015	January 29, 2020	1,075,000	1,075,000
$0.39	March 1, 2015	March 1, 2020	100,000	100,000
$0.08	February 11, 2016	February 11, 2021	1,685,000	1,685,000
$0.08	February 12, 2016	February 12, 2021	125,000	125,000
$0.25	September 21, 2017	September 21, 2022	5,034,000	1,678,000
$0.28	October 2, 2017	October 2, 2022	150,000	50,000
$0.25	January 1, 2018	January 1, 2023	250,000	83,333
			8,419,000	4,796,333
Weighted-average exercise price			$0.21	$0.19

Liquidity and Capital Management

The Company's net debt as at September 30, 2018 and December 31, 2017 were $31,207,369 and $18,558,361 respectively, representing an increase in net debt of $12,649,008.

a) Financing

The Company's net cash provided by financing activities during the three and nine months ended September 30, 2018 were $4,928,635 and $8,573,645 respectively. These funds are from the proceeds, net of debt issuance costs, which the Company received from the additional draws on the term loan in February 2018 of US$3.0 million (as further disclosed in Note 12 of the Company's quarterly financial statements for the period ended March 31, 2018) and July 2018 of US$4.0 million. These funds were used for expenditures in the Company's spring and summer drilling programs.

b) Term Loan

On September 15, 2017, the Company entered into a first lien senior secured credit agreement (the "Credit Agreement") with a third-party lender (the "Lender") providing for a multi-draw, non-revolving term loan facility of a maximum aggregate principal amount of up to US$35.0 million. Security granted by the Company under the Credit Agreement included a demand debenture for US$75.0 million which provides for a first ranking security interest and floating and fixed charges over all of the real and personal property present and after acquired of the Company.

An initial commitment amount of US$15.0 million (the "Term Loan") was granted at inception and on January 23, 2018 and June 1, 2018 the Company amended its credit agreement with its Lender to increased commitment of US$5.0 million and US$10.0 million respectively. This brings the company's aggregate amount committed by the Lender under the Term Loan to US$30.0 million.

As at September 30, 2018 the Company has drawn US$22.0 million (CAD$28,241,400). The Company's ability to access additional commitments in excess of US$30.0 million is subject to approval of the Lender based on review and approval of the Company's future development plans.

The interest rate for the Term Loan is the three-month United States dollar London Interbank Offered Rate ("LIBOR") with a LIBOR floor of 1%, plus 7.50% payable quarterly, for a five-year term with a maturity date of September 15, 2022. In conjunction, the Company issued 13,750,000 warrants entitling the Lender to purchase one common share of Hemisphere at an exercise price of $0.28/share prior to September 15, 2022.

The Term Loan is subject to certain financial and performance covenants commencing in the second quarter ended June 30, 2018:

1. Interest coverage ratio for the quarter ended June 30, 2018 shall not be less than 2.00 to 1.00; quarter ended September 30, 2018 shall not be less than 2.25 to 1.00; quarter ended

December 31, 2018 shall not be less than 2.50 to 1.00; quarter ended March 31, 2019 and each quarter thereafter shall not be less than 3.00 to 1.00.
Interest coverage ratio, as defined in the Credit Agreement, means the ratio as of the last day of any fiscal quarter of (a) Consolidated Adjusted EBITDAX as defined below for the applicable fiscal quarter to (b) Consolidated Interest Expense for such fiscal quarter.

2. Total leverage ratio for the quarter ended June 30, 2018 shall not be more than 5.25 to 1.00; quarter ended September 30, 2018 shall not be more than 4.75 to 1.00; quarter ended December 31, 2018 shall not be more than 4.25 to 1.00; quarters ended March 31, 2019 and June 30, 2019 shall not be more than 3.50 to 1.00; quarter ended September 30, 2019 and each quarter thereafter shall not be more than 3.25 to 1.00.

   Total leverage ratio, as defined in the Credit Agreement, means the ratio as of the last day of any fiscal quarter of (a) Consolidated Total Debt as of such date to (b) Consolidated Adjusted EBITDAX for the fiscal quarter ending on such date calculated on an annualized basis.

3. Minimum average production for the quarter ended June 30, 2018 will not be less than 750 boe/d; quarters ended September 30, 2018 and December 31, 2018 will not be less than 1,100 boe/d; quarters ended March 31, 2019 and June 30, 2019 will not be less than 1,300 boe/d; quarter ended September 30, 2019 and each quarter thereafter will not be less than 1,500 boe/d.

4. Proved developed producing coverage ratio for the quarter ended June 30, 2018, based on reserve reports internally prepared by Hemisphere, and each quarter thereafter shall not be less than 1.00 to 1.00.

   Proved developed producing coverage ratio, as defined in the Credit Agreement, means as of any date of determination, the ratio of (a) proved developed producing reserves on a pre-tax basis at 10% to (b) the sum of (i) Consolidated Total Debt and (ii) without duplication of clause (a) above, all obligations (after giving effect to any netting requirements) under any swap agreement that such person would be required to pay if the swap agreement was terminated at such time, in each case, as of such date. Notwithstanding anything to the contrary contained herein, after giving effect to the netting contemplated by clause (ii) above, in no event shall amounts owing to any credit party under any swap agreement result in a reduction of the obligations referred to in clause (b).

5. Total proved reserves coverage ratio for the quarter ended June 30, 2018, based on reserve reports internally prepared by Hemisphere, and each quarter thereafter shall not be less than 1.50 to 1.00.

   Total proved reserves coverage ratio, as defined in the Credit Agreement, means as of any date of determination, the ratio of (a) the Total Proved reserves on a pre-tax basis discounted at 10% to (b) the sum of (i) Consolidated Total Debt and (ii) without duplication of clause (a) above, all obligations (after giving effect to any netting requirements) under any swap agreement that such person would be required to pay if the swap agreement were terminated at such time, in each case, as of such date. Notwithstanding anything to the contrary contained herein, after giving effect to the netting contemplated by clause (ii) above, in no event shall amounts owing to any credit party under any swap agreement result in a reduction of the obligations referred to in clause (b).

For the period ending September 30, 2018 the company has met all of the financial and performance covenants in effect.

Definition of certain terms as defined in the Credit Agreement:

Consolidated Interest Expense means, for any period, total cash interest expense (excluding accretion of asset retirement obligation and debt issuance costs and including that portion attributable to capital leases in accordance with GAAP and capitalized interest) of the credit parties and their subsidiaries on a consolidated basis with respect to all outstanding Consolidated Total Debt.

Consolidated Total Debt means, as at any date of determination: (a) the aggregate amount of all Indebtedness of the credit parties and their Subsidiaries determined on a consolidated basis in accordance with GAAP plus (b) the aggregate outstanding amount, without duplication, of attributable debt of the credit parties and their subsidiaries determined on a consolidated basis.

Consolidated Adjusted EBITDAX means, for any period, an amount determined for the Company on a consolidated basis equal to:

the amounts for such period of consolidated net income,

<u>plus</u>

the sum, without duplication, of the amounts for such period of the following expenses (or charges) to the extent deducted from consolidated net income during such period:

(i) Consolidated Interest Expense, <u>plus</u>
(ii) Provisions for taxes based on income (including margin or gross receipts taxes), <u>plus</u>
(iii) Total depreciation and amortization expense, <u>plus</u>
(iv) Impairment or asset write-down expense, <u>plus</u>
(v) Accretion of asset retirement obligation and debt issuance costs, <u>plus</u>
(vi) Share-based compensation expense, <u>plus</u>
(vii) Non-cash losses resulting from the mark-to-market exposure of outstanding swaps and unrealized foreign exchange exposure, <u>plus</u>
(viii) Other non-Cash items reducing consolidated net income (excluding any such non-cash item to the extent that it represents an accrual or reserve for potential Cash items in any future period or amortization of a prepaid Cash item that was paid in a prior period),

<u>minus</u>

the sum, without duplication of the amounts for such period of the following items to the extent increasing consolidated net income during such period:

i) Other non-Cash items increasing consolidated net income for such period (excluding any such non-Cash item to the extent it represents the reversal of an accrual or reserve for potential Cash item in any prior period), plus

ii) Interest income, plus

iii) Non-cash gains resulting from the mark-to-market exposure of outstanding swaps and unrealized foreign exchange exposure.

The Company also has a financial covenant for its cash General and Administrative costs ("G&A costs") that it shall not exceed 105% of the cash G&A costs cap of $2.5 million per annum as at December 31, 2018.

For the period ending September 30, 2018 the company has met all of the financial and performance covenants in effect, as follows:

Ratio			Required	Actual Sep. 30, 2018	
1.	Interest Coverage Ratio	Greater than	2.25	2.96	
2.	Total Leverage Ratio	Less than	4.75	3.42	
3.	Minimum Average Production	Greater than	1100	1,150	Boe/d
4.	Proved Developed Producing Coverage Ratio	Greater than	1.00	1.32	
5.	Total Proved Reserves Coverage Ratio	Greater than	1.50	2.02	

Further details on the calculations of the covenants can be found in the Credit Agreement and the amendment thereto filed on SEDAR at www.sedar.com on September 22, 2017 and February 1, 2018, respectively, under the Company's profile.

c) Capital Management

The Company manages its capital with the following objectives:

- Ensure sufficient flexibility to achieve the Company's ongoing business objectives including the replacement of production, funding of future growth opportunities, and pursuit of accretive acquisitions; and

- Maximize shareholder return through enhancing the Company's share value.

The Company monitors its capital structure and makes adjustments according to market conditions in an effort to meet its objectives given the current outlook of the business and industry in general. The capital structure of the Company is composed of shareholders' equity and the Term Loan. The Company may manage its capital structure by issuing new shares, repurchasing outstanding shares, incurring additional indebtedness under the Term Loan, issuing new debt instruments, other financial or equity-based instruments, adjusting capital spending, or disposing of assets. The capital structure is reviewed on an ongoing basis.

Commitment

The Company has a commitment to make monthly rental payments pursuant to the office rental agreement at its current location until May 31, 2023.

As at September 30, 2018, the gross balance of the Term Loan was $28,241,400 (US$22,000,000), exclusive of the debt issuance costs. The Term Loan matures on September 15, 2022.

		2018	2019	2020	2021	2022	2023	Total
Office Rental	$	34,669	138,676	138,676	138,676	138,676	57,782	647,153
Term Loan		-	-	-	-	28,241,400	-	28,241,400
Term Loan Interest		622,723	2,490,891	2,490,891	2,490,891	1,868,169	-	9,963,566
	$	657,392	2,629,567	2,629,567	2,629,567	30,248,245	57,782	38,852,119

Off-Balance Sheet Arrangements

The Company has not entered into any off-balance sheet transactions.

Proposed Transactions

As of the effective date, there are no outstanding proposed transactions.

Future Accounting Pronouncements

The Company has reviewed new and revised accounting pronouncements listed below that have been issued but are not yet effective. There are no other standards or interpretations issued, but not yet adopted, that are anticipated to have a material effect on the reported earnings or net assets of the Company.

Leases - In January 2016, the IASB issued IFRS 16 *Leases*, which replaces the current IFRS guidance onleases. Under the current guidance, lessees are required to determine if the lease is a finance or operating lease, based on specified criteria. Finance leases are recognized on the balance sheet, while operating leases are recognized in profit or loss when the expense is incurred. Under IFRS 16, lessees must recognize a lease liability and a right-of-use asset for virtually all lease contracts. The recognition of the present value of minimum lease payments for certain contracts currently classified as operating leases will result in increases to assets, liabilities, depletion, depreciation and amortization, and finance expense, and a decrease to production and transportation expenses upon implementation. An optional exemption to not recognize certain short-term leases and leases of low value can be applied by lessees. For lessors, the accounting remains essentially unchanged. The standard will be effective for annual periods beginning on or after January 1, 2019. Early adoption is permitted, provided IFRS 15 *Revenue from Contracts with Customers*, has been applied, or is applied at the same date as IFRS 16. The Company is currently evaluating the impact of adopting IFRS 16 on the Company's consolidated financial statements and is in the process of gathering and analyzing contracts that will fall into the scope of this standard.

Changes in Accounting Policies

Adoption of IFRS 15, "Revenues from Contracts with Customers"

IFRS 15, "Revenue from Contracts with Customers" ("IFRS 15") was issued by the IASB in May of 2014 and replaces IAS 18 "Revenue", IAS 11 "Construction Contracts", and related interpretations effective for reporting periods beginning on or after January 1, 2018. The new standard provides a single, principles based five-step analysis of transactions to determine the nature of an entity's obligation to perform and whether, how much and when revenue is recognized. New estimates and judgmental thresholds have been introduced, which may affect the amount and/or timing of revenue recognized.

The Company has adopted IFRS 15 effective January 1, 2018. The Company applied IFRS 15 to all of its contracts with customers using the modified retrospective method. Under this method, prior period financial
statements have not been restated. Management reviewed the Company's revenue streams and major contracts with customers using the IFRS 15 principles-based five-step model and concluded there were no material changes to earnings or in the timing of when production revenue is recognized.

Adoption of IFRS 9, "Financial Instruments"

On January 1, 2018, the Company adopted all of the requirements of IFRS 9, "Financial Instruments" ("IFRS 9") which replaces IAS 39, "Financial Instruments: Recognition and Measurement" ("IAS 39"). The retrospective adoption of IFRS 9 had no material impact to the Company's financial statements.

IFRS 9 contains three principal classification categories for financial assets: measured at amortized cost; fair value through other comprehensive income ("FVOCI"); or fair value through profit or loss ("FVTPL"). The classification of financial assets under IFRS 9 is generally based on the business model in which a financial asset is managed and its contractual cash flow characteristics. IFRS 9 eliminates the previous IAS 39 categories of held to maturity, loans and receivables and available for sale. IFRS 9 largely retains the existing requirements in IAS 39 for the classification of financial liabilities.

IFRS 9 replaces the "incurred loss" model in IAS 39 with an "expected credit loss" model. The application of the new expected credit loss model did not have an impact on the Company's financial assets. Cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities and term loan continue to be measured at amortized cost and are now classified as "amortized cost". There were no changes to the Company's classification of its financial instrument derivative assets and liabilities as FVTPL. The Company currently has no intentions of designating any of its financial instruments as hedges, nor does the Company currently apply hedge accounting.

Financial Instruments

Fair value estimates of financial instruments are made at a specific point in time, based on relevant information about financial markets and specific financial instruments. As these estimates are subjective in nature, involving uncertainties and matters of significant judgment, changes in assumptions can significantly affect estimated fair values. At December 31, 2017, the Company's financial instruments include accounts receivable, reclamation deposits, bank indebtedness, and accounts payable and accrued liabilities.
The fair values of accounts receivable, reclamation deposits, accounts payable and accrued liabilities, and bank indebtedness approximate their carrying values due to the short-term maturity of these financial instruments.

(a) Fair value hierarchy

Fair value measurements of financial instruments are required to be classified using a fair value hierarchy that reflects the significance of inputs in making the measurements. The levels of the fair value hierarchy are defined as follows:

Level 1 - Quoted prices (unadjusted) in active markets for identical assets or liabilities.

Level 2 - Inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly.

Level 3 - Inputs for the asset or liability that are not based on observable market data.

(b) Non-derivative financial instruments

Financial assets

At initial recognition, financial assets are classified into four main categories: loans and receivables; held-to-maturity investments; available for sale financial assets; or financial assets at fair value through profit or loss. All financial assets are recognized initially at fair value, normally being the transaction price, plus any directly attributable transaction costs. Transaction costs for instruments at fair value through profit or loss are recognized immediately in earnings.

The subsequent measurement of financial assets depends on their classification.

Loans, receivables and held-to-maturity investments are subsequently measured at amortized cost using the effective interest method, less any impairment losses. Gains and losses are recognized in earnings when the asset is derecognized or impaired, as well as through the amortization process.

Available-for-sale financial assets are subsequently measured at fair value, with changes in fair value recognized directly in other comprehensive income until the asset is derecognized or determined to be impaired, at which time the cumulative change in fair value previously reported in other comprehensive income is recognized in earnings.

Financial assets at fair value through profit or loss are subsequently measured at fair value, with changes in those fair values recognized in earnings.

Financial assets are derecognized when the contractual rights to the cash flows expire, or when substantially all the risks and rewards of ownership of the financial asset are transferred to a third party.
Financial assets and liabilities are shown separately in the statement of financial position unless the Company has a legal right to offset the amounts and intends to either settle on a net basis or to realize the asset and settle the liability simultaneously, in which case they are presented on a net basis.

Impairment of financial assets

A financial asset that is not carried at fair value through profit or loss is assessed at each reporting date to determine whether there is any objective evidence that it is impaired. A financial asset is considered to be impaired if objective evidence indicates that a loss event has occurred after initial recognition and has had a negative effect on the estimated future cash flows of that asset that can be estimated reliably.

An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the present value of the estimated future cash flows discounted at the asset's original effective interest rate.

The Company considers evidence of impairment for receivables at both a specific asset and collective level. All individually significant financial assets are tested for impairment on an individual basis. All individually significant receivables found not to be specifically impaired are then collectively assessed for any impairment that has been incurred but not yet identified. The remaining financial assets are assessed collectively for impairment in groups that share similar credit risk characteristics.

In assessing collective impairment the Company uses historical trends of the probability of default, timing of recoveries and the amount of loss incurred, adjusted for management's judgment as to whether current economic and credit conditions are such that the actual losses are likely to be greater or less than suggested by historical trends.

All impairment losses are recognized in earnings.

An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized. For financial assets measured at amortized cost the reversal is recognized in earnings.

Financial liabilities

At initial recognition, financial liabilities are classified as either financial liabilities at fair value through profit or loss, or other financial liabilities. All financial liabilities are recognized initially at fair value, normally being the transaction price less any directly attributable transaction costs. Transaction costs for instruments at fair value through profit or loss are recognized immediately in earnings.
The subsequent measurement of financial liabilities depends on their classification.

Financial liabilities at fair value through profit or loss are subsequently measured at fair value, with changes in those fair values recognized in earnings.
Other financial liabilities are subsequently measured at amortized cost using the effective interest method.
Financial liabilities are derecognized when the contractual obligation expires, is discharged, or cancelled. Gains and losses arising on the repurchase, settlement or cancellation of liabilities are recognized in earnings.

(c) Financial derivative instruments

The Company may use financial derivative contracts in order to manage the exposure to market risks from fluctuations in commodity prices and foreign exchange. 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 derivative contracts to be economic hedges. As a result, all financial derivative contracts are classified as fair value through profit or loss and are recognized at fair value. Transaction costs are recognized in earnings when incurred.

Physical delivery contracts are entered into for the purpose of delivery of oil in accordance with the Company's expected sale requirements, and therefore are not recorded in the statement of financial position. These contracts are recorded in revenue on their settlement dates.

Embedded derivatives are separated from the host contract and accounted for separately if the economic characteristics and risks of the host contract and the embedded derivative are not closely related, a separate instrument with the same terms as the embedded derivative would meet the definition of a derivative, and the combined instrument is not measured at fair value through profit or loss. Changes in the fair value of separable embedded derivatives are recognized in earnings, if material.

Risks

The Company's activities expose it to a variety of risks that arise as a result of its exploration, development, production and financing activities. These risks and uncertainties include, among other things, volatility in market prices for oil and natural gas, general economic conditions in Canada, the US and globally and other factors described under "Risk Factors" in Hemisphere's most recently filed Annual Information Form which is available on the Company's website at www.hemisphereenergy.ca or on SEDAR at www.sedar.com. Readers are cautioned that this list of risk factors should not be construed as exhaustive.

The following provides information about the Company's exposure to some risks associated with the oil and gas industry, as well as the Company's objectives, policies and processes for measuring and managing risk.

Business Risk

Oil and gas exploration and development involves a high degree of risk whereby many properties are ultimately not developed to a producing stage. There can be no assurance that the Company's future exploration and development activities will result in discoveries of commercial bodies of oil and gas. Whether an oil and gas property will be commercially viable depends on a number of factors including the particular attributes of the reserve and its proximity to infrastructure, as well as commodity prices and government regulations, including regulations relating to prices, taxes, royalties, land tenure, land use, and environmental protection. The exact effect of these factors cannot be accurately predicted, and the combination of these factors may result in an oil and gas property not being profitable.

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its payment obligations. This risk arises principally from the Company's receivables from joint operators and oil and natural gas marketers, and reclamation deposits. The credit risk associated with reclamation deposits is minimized substantially by ensuring this financial asset is placed with major financial institutions with strong investment-grade ratings by a primary ratings agency. The credit risk associated with accounts receivable is mitigated as the Company monitors monthly balances to limit the risk associated with collections. The Company does not anticipate any default. There are no balances past due past 90 days or impaired.

The maximum exposure to credit risk is as follows:

	As at	
	September 30, 2018	December 31, 2017
Accounts receivable		
Marketing receivables	**$ 1,884,020**	$ 1,284,474
Trade receivables	**291,869**	76,437
Receivables from joint venture	**54**	7,297
Reclamation deposits	**115,535**	115,535
Total	**$ 2,251,478**	$ 1,483,743

The Company sells the majority of its oil production to a single oil marketer and, therefore, is subject to concentration risk which is mitigated by management's policies and practices related to credit risk, as discussed above. The Company historically has never experienced any collection issues with its oil marketer.

Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they come due. The Company regularly prepares and updates budgets and forecasts in order to monitor its liquidity and ability to meet its financial obligations and commitments, including the ability to comply with the financial covenants under the Company's Term Loan. The volatility in commodity prices (most notably the recent increase in heavy oil differentials) and foreign exchange rates may adversely affect the Company's operating results and financial position and it is possible that the Company could breach one or more of its financial covenants. A covenant violation is considered an event of default under the Term Loan, and if not remedied or waived by lenders, results in the right of lenders to demand repayment of all amounts owed.

In response to current volatile crude oil prices and differentials, the Company has proactively entered into an agreement with the Lender to temporarily waive the application of and compliance with its two financial covenants (being the interest coverage ratio and total leverage ratio covenants) and two reserve-based covenants (being the PDP coverage ratio and total proved reserve coverage ratio covenants) that are included in the credit agreement with the lender, in each case for the fiscal quarter ending December 31, 2018.

At September 30, 2018, the Company had net debt (current assets less current liabilities excluding fair value of financial instruments, and outstanding Term Loan) of $31,207,369 (December 31, 2017 - $18,558,361), which includes Term Loan of $28,241,400 (December 31, 2017 - $18,868,500). The Company funds its operations through production revenue and the Term Loan.

Market risk

Market risk is the risk that changes in market prices, such as, foreign exchange rates, commodity prices, and interest rates will affect the value of the financial instruments. Market risk is comprised of interest rate risk, foreign currency risk, commodity price risk, and other price risk.

Interest rate risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. Borrowings under the Company's Term Loan are subject to variable interest rates. A one percent change in interest rates would have a $250,000 annual effect on net income (loss) and comprehensive income (loss).

Foreign currency risk

The Company's functional and reporting currency is Canadian dollars. The Company does not sell or transact in any foreign currency; except i) the Company's commodity prices are largely denominated in USD, and as a result the prices that the Company receives are affected by fluctuations in the exchange rates between the USD and the Canadian dollar. The exchange rate effect cannot be quantified, but generally an increase in the value of the Canadian dollar compared to the USD will reduce the prices received by the Company for its crude oil and natural gas sales. The Company does have foreign exchange rate swaps in place as further disclosed within this MD&A and the audited annual financial statements for the year ended December 31, 2017; and ii) the Company's Term Loan is denominated in USD and, as a result, the amount that the Company will be obligated to repay at the term of the loan will be affected by fluctuations in the exchange rate between the USD and the Canadian dollar at that time. A 100 basis points change in the foreign exchange rate would have a $286,728 effect on the annual net loss and comprehensive loss.

Commodity price risk

Commodity prices for petroleum and natural gas are impacted by global economic events that dictate the levels of supply and demand, as well as the relationship between the Canadian dollar and the USD. Significant changes in commodity prices may materially impact the Company's funds flow from operations, and ability to raise capital. The Company has derivative commodity contracts in place as further disclosed within this MD&A and the audited annual financial statements for the year ended December 31, 2017.

Other price risk

Other price risk is the risk that the fair or future cash flows of a financial instrument will fluctuate due to changes in market prices, other than those arising from interest rate risk, foreign currency risk or commodity price risk. The Company is not exposed to significant other price risk.

Non-IFRS Measures

This document contains the terms "funds flow from (used in) operations," "operating netback" and "net debt" which are not recognized measures under IFRS and may not be comparable to similar measures presented by other companies.

a) The Company considers funds flow from operations to be a key measure that indicates the Company's ability to generate the funds necessary to support future growth through capital investment and to repay any debt. Funds flow from operations is a measure that represents cash generated by operating activities, before changes in non-cash working capital and may not be comparable to measures used by other companies. Funds flow from operations per share is calculated using the same weighted-average number of shares outstanding as in the case of the earnings per share calculation for the period.

A reconciliation of funds flow from (used in) operations to cash provided by (used in) operating activities is presented as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2018	2017	**2018**	2017
Cash provided by operating activities	**$ 2,192,826**	$ 955,786	**$ 1,998,995**	$ 1,748,849
Less: Change in non-cash working capital	**805,358**	297,947	**(739,285)**	(12,399)
Funds flow from operations	**$ 1,387,468**	$ 657,840	**$ 2,738,280**	$ 1,761,249
Per share, basic and diluted	**$ 0.02**	$ 0.01	**$ 0.03**	$ 0.02

b) Operating field netback is a benchmark used in the oil and natural gas industry and a key indicator of profitability relative to current commodity prices. Operating field netback is calculated as oil and gas sales, less royalties, operating expenses and transportation costs on an absolute and per boe basis. These terms should not be considered an alternative to, or more meaningful than, cash flow from operating activities or net income or loss as determined in accordance with IFRS as an indicator of the Company's performance.

Operating netback is a non-IFRS measure calculated as the operating field netback plus the Company's realized commodity hedging gain (loss) on an absolute and per barrel of oil equivalent.

c) Net debt (working capital) is closely monitored by the Company to ensure that its capital structure is maintained by a strong balance sheet to fund the future growth of the Company. Net debt is used in this document in the context of liquidity and is calculated as the total of the Company's bank debt and current liabilities, less current assets. There is no IFRS measure that is reasonably comparable to net debt.

The following table outlines the Company calculation of net debt:

	As at	
	September 30, 2018	December 31, 2017
Current assets(1)	**$ 2,618,929**	$ 2,955,446
Current liabilities(2)	**(5,584,897)**	(2,645,307)
Term Loan	**(28,241,400)**	(18,868,500)
Net debt	**$ (31,207,368)**	$ (18,558,361)

Note:
(1) excluding fair value of financial instruments
(2) gross loan amount including foreign exchange

Boe Conversion

Within this document, petroleum and natural gas volumes and reserves are converted to a common unit of measure, referred to as a barrel of oil equivalent ("boe"), using a ratio of 6,000 cubic feet of natural gas to one barrel of oil. Use of the term boe may be misleading, particularly if used in isolation. The conversion ratio is based *on an energy equivalent method and does not necessarily represent a value equivalency at the wellhead. This conversion conforms with the Canadian Securities Regulators National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities ("NI 51-101").*

Forward-Looking Statements

In the interest of providing Hemisphere's shareholders and potential investors with information regarding the Company, including management's assessment of the future plans and operations of Hemisphere, certain statements contained in this MD&A constitute forward-looking statements or information (collectively "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements are typically identified by words such as "anticipate", "continue", "estimate", "expect", "forecast", "may", "will", "project", "could", "plan", "intend", "should", "believe", "outlook", "potential", "target" and similar words suggesting future events or future performance. In particular, but without limiting the foregoing, this document may contain forward-looking statements pertaining to the following: volumes and estimated value of Hemisphere's oil and natural gas reserves; the life of Hemisphere's reserves; the volume and product mix of Hemisphere's oil and natural gas production; future oil and natural gas prices; future operational activities; and future results from operations and operating metrics, including any future production growth and net debt. In addition, statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated and can be profitably produced in the future.

With respect to forward-looking statements contained in this MD&A, the Company has made assumptions regarding, among other things: future capital expenditure levels; future oil and natural gas prices and differentials between light, medium and heavy oil prices; results from operations including future oil and natural gas production levels; future exchange rates and interest rates; Hemisphere's ability to obtain equipment in a timely manner to carry out development activities; Hemisphere's ability to market its oil and natural gas successfully to current and new customers; the impact of increasing competition; Hemisphere's ability to obtain financing on acceptable terms; and Hemisphere's ability to add production and reserves through our development and exploitation activities.

Although Hemisphere believes that the expectations reflected in the forward-looking statements contained in this MD&A, and the assumptions on which such forward-looking statements are made, are reasonable, there can be no assurance that such expectations will prove to be correct. Readers are cautioned not to place undue reliance on forward-looking statements included in this MD&A, as there can be no assurance that the plans, intentions or expectations upon which the forward-looking statements are based will occur. By their nature, forward-looking statements involve numerous assumptions, known and unknown risks and uncertainties that contribute to the possibility that the predictions, forecasts, projections and other forward-looking statements will not occur, which may cause Hemisphere's actual performance and financial results in future periods to differ materially from any estimates or projections of future performance or results expressed or implied by such forward-looking statements. These risks and uncertainties include, among other things, the following: volatility in market prices for oil and natural gas; general economic conditions in Canada, the U.S. and globally; and the other factors described under "Risk Factors" in Hemisphere's most recently filed Annual Information Form available on the Company's website at www.hemisphereenergy.ca or on SEDAR at www.sedar.com. Readers are cautioned that this list of risk factors should not be construed as exhaustive.

The forward-looking statements contained in this MD&A speak only as of the date of this document. Except as expressly required by applicable securities laws, Hemisphere does not undertake any obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained in this MD&A are expressly qualified by this cautionary statement.