Q2 2018 Hemisphere energy corporation

TSX-V: HME

www.hemisphereenergy.ca

Q2 2018 HIGHLIGHTS

- Achieved record quarterly average production of 1053 boe/d (96% oil), a 76% increase over the second quarter of 2017.
- Increased revenue by 132% to $5.6 million compared to $2.4 million for the second quarter of 2017.
- Increased operating netbacks, including losses on commodity contracts, to $24.27/boe, an increase of 21% from the second quarter of 2017.
- Generated funds flow from operations of $1.3 million ($0.01/share), an increase of 109% over the second quarter of 2017.
- Drilled the first two wells of an 11-well summer program.
- Amended credit agreement to reflect an increased commitment of US$15.0 million to the term loan, bringing the aggregate amount committed by the lender to US$30 million.
- Achieved a Corporate Liability Management Ratio ("LMR") with the Alberta Energy Regulator of 6.17 at the end of the second quarter 2018, which is within the top 13% of all licensees evaluated.

CORPORATE UPDATE

Since securing a five year term loan in September, 2017, Hemisphere has drilled 18 new wells including 12 drilled to-date in 2018. Current production of approximately 1254 boe/d (based on field estimates for the week of Aug 13-19) includes new production from three of the recent drills and is more than double that from the second quarter of 2017. Ongoing operations include drilling two more wells in Atlee Buffalo through August and early September, completing and putting on production the remainder of the summer drilling program wells by the end of the third quarter of 2018, expanding both of the Atlee F and G pool batteries to handle significantly increasing production, and preparing for further drilling operations through the winter.

Hemisphere has spent the last three years implementing its enhanced oil recovery projects in Atlee Buffalo and currently only 10% of the total original-oil-in-place from the Atlee Buffalo Upper Mannville F and G pools, as mapped by McDaniel and Associates Consultants Ltd. ("McDaniel") for the purposes of its independent reserve report dated effective as of December 31, 2017 (the "Reserve Report"), is captured on a proved reserve basis in the Reserve Report, with 12% captured on a proved plus probable basis. Analogue waterflood pools within two townships of the Company's Atlee Buffalo property have recovered up to 40% of original-oil-in-place through secondary and tertiary recovery schemes. Management anticipates significant reserve additions through 2018 with the level of activity achieved this year to enhance the development and establish the productivity of these pools.

Hemisphere expects to complete its capital program in 2018 with debt levels within its term loan commitment level of US$30 million, which allows for room to continue a capital program through the first quarter of 2019. Currently up to eight wells are being planned for the first quarter of 2019.

Hemisphere's corporate strategy is to achieve organic production and reserve growth in order to improve profitability and financial flexibility. With continued success of its waterflood projects, the Company expects to see sustained increases in production and reserves through the year. Management believes the Company has considerable growth upside through development of its exceptional assets.

Q2 2018 FINANCIAL AND OPERATING HIGHLIGHTS

	Three Months Ended June 30		Six Months Ended June 30	
	2018	2017	**2018**	2017
OPERATING				
Average daily production				
Oil (bbl/d)	**1,012**	549	**911**	539
Natural gas (Mcf/d)	**235**	296	**258**	303
NGL (bbl/d)	**2**	2	**2**	2
Combined (boe/d)	**1,053**	600	**956**	591
Oil and NGL weighting	**96%**	92%	**96%**	91%
Average sales prices				
Oil ($/bbl)	**$ 60.64**	$ 46.85	**$ 54.07**	$ 46.57
Natural gas ($/Mcf)	**1.17**	2.73	**1.67**	2.77
NGL ($/bbl)	**61.48**	46.30	**58.02**	46.64
Combined ($/boe)	**$ 58.64**	$ 44.34	**$ 52.09**	$ 44.02
Operating netback ($/boe)				
Petroleum and natural gas revenue	**$ 58.64**	$ 44.34	**$ 52.09**	$ 44.02
Royalties	**10.39**	7.19	**8.73**	6.46
Operating costs	**11.08**	16.20	**12.85**	16.79
Transportation costs	**2.95**	2.81	**2.79**	2.94
Operating field netback(1)	**34.23**	18.14	**27.73**	17.83
Realized commodity hedging (gain) loss	**9.96**	(1.96)	**8.74**	(1.37)
Operating netback(2)	$ **24.27**	$ 20.09	**$ 18.99**	$ 19.19
FINANCIAL				
Petroleum and natural gas revenue	**$ 5,618,915**	$ 2,419,666	**$ 9,012,836**	$ 4,712,412
Operating netback(2)	**2,325,836**	1,096,412	**3,284,932**	2,054,688
Funds flow from operations(3)	**1,251,089**	598,078	**1,350,810**	1,103,409
Per share, basic and diluted	**0.01**	0.01	**0.02**	0.01
Net income (loss)	**(2,253,163)**	(206,724)	**(4,642,556)**	(345,402)
Per share, basic and diluted	**(0.03)**	(0.00)	**(0.05)**	(0.00)
Capital expenditures	**2,532,877**	661,307	**5,402,941**	917,821
Net debt(4)	**23,734,580**	10,605,594	**23,734,580**	10,605,594
Bank indebtedness	**-**	10,463,948	**-**	10,463,948
Term Loan(5)	**$ 23,637,600**	$ -	**$ 23,367,600**	$ -

Notes:

(1) 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.

(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

	2018	2017
SHARE CAPITAL		
Common shares outstanding	**89,793,302**	89,793,302
Stock options outstanding	**8,419,000**	2,985,000
Warrants outstanding	**13,750,000**	-
Fully Diluted	**111,962,302**	92,778,302
Weighted-average shares outstanding – basic and diluted	**89,793,302**	88,361,894

MANAGEMENT'S DISCUSSION AND ANALYSIS

Dated as at August 22, 2018

The following Management's Discussion and Analysis ("MD&A") is a review of the operations and current financial position for the three and six months ended June 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 six months ended June 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 $1,251,089 ($0.01/share) during the second quarter of 2018, as compared to funds flow from operations of $598,077 ($0.00/share) during the second quarter of 2017. Funds flow for the six months ended June 30, 2018 increased to $1,350,810 ($0.02/share) from $1,103,409 ($0.01/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 $954,002 loss from hedging contracts, which 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 six months ended June 30, 2018, the Company reported net losses of $2,253,163 ($0.03/share) and $4,642,556 ($0.05/share), respectively, compared to net losses of $206,724 ($0.00/share) and $345,402 ($0.00/share) for the three and six months ended June 30, 2017, respectively. The higher losses during the comparable six months ended June 30, 2018 are primarily attributed to the increases in hedging losses, finance expense and foreign exchange loss, in the amounts of $4,281,833, $1,057,930 and $1,004,770 respectively.

Production

	Three Months Ended June 30		Six Months Ended June 30	
By product:	**2018**	2017	**2018**	2017
Oil (bbl/d)	**1,012**	549	**911**	539
Natural gas (Mcf/d)	**234**	296	**258**	303
NGL (bbl/d)	**2**	2	**2**	2
Total (boe/d)	**1,053**	600	**956**	591
Oil and NGL weighting	**96%**	92%	**96%**	91%

In the second quarter of 2018, the Company's average daily production was 1,053 boe/d (96% oil and NGL) representing a 76% increase over the comparable quarter in 2017. For the six months ended June 30, 2018, the Company's average daily production was 956 boe/d (96% oil and NGL), representing a 62% increase from 591 boe/d (91% oil and NGL) for the same period in 2017. This increase in production can be attributed to new wells from the fall of 2017 and the first quarter of 2018 drilling programs as well as the continued success and improvement of the waterflood projects in the Upper Mannville F and G pools.

Average Benchmark and Realized Prices

	Three Months Ended June 30		Six Months Ended June 30	
	2018	2017	**2018**	2017
Benchmark prices				
WTI ($US/bbl)(1)	**$ 67.88**	$ 48.27	**$ 65.38**	$ 50.09
Exchange rate (1 $US/$C)	**1.2906**	1.3440	**1.2775**	1.3336
WTI ($C/bbl)	**87.61**	64.88	**83.51**	66.79
WCS ($C/bbl)(2)	**62.81**	49.96	**55.78**	49.68
AECO natural gas ($/Mcf)(3)	**1.20**	2.79	**1.63**	2.74
Average realized prices				
Crude oil ($/bbl)	**60.64**	46.85	**54.07**	46.57
Natural gas ($/Mcf)	**1.17**	2.73	**1.67**	2.77
NGL ($/bbl)	**61.48**	46.30	**58.02**	46.64
Combined ($/boe)	**$ 58.64**	$ 44.34	**$ 52.09**	$ 44.02

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 32% from $44.34/boe during the three months ended June 30, 2017 to $58.64/boe during three months ended June 30, 2018. The Company's combined average realized price increased by 18% from $44.02/boe during the six months ended June 30, 2017 to $52.09/boe during six months ended June 30, 2018. These increases are the result of higher oil prices during the three and six months ended June 30, 2018 which are reflected in the respective $13.79/bbl and $7.50/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 six months ended June 30, 2018 by $1.56/Mcf and $1.10/Mcf, respectively, over the comparable periods in 2017.

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

Product	Type	Volume	Price	Index	Term
Crude oil	Swap(1)	150 bbl/d	US$54.65	WTI-NYMEX	November 1, 2017 – June 30, 2018
Crude oil	Swap	300 bbl/d	US$50.67	WTI-NYMEX	January 1, 2018 – December 31, 2018
Crude oil	Swap	100 bbl/d	US$21.90	WCS	April 1, 2018 – September 30, 2018
Crude oil	Swap	400 bbl/d	US$18.45	WCS	May 1, 2018 – September 30, 2018
Crude oil	Option(1)	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

Note:
(1) The counter-party to this contract has enacted their one time option to extend a swap on 150 bbl/d of crude oil at US$54.65 for the term indicated as of June 30, 2018.

At June 30, 2018 the commodity contracts were fair valued as a liability of $5,015,918 recorded on the balance sheet, and an unrealized loss for the three and six month periods of $1,835,467 and $2,592,636 respectively (June 30, 2017 – loss $48,919 and gain 30,130 respectively).

Revenue

	Three Months Ended June 30		Six Months Ended June 30	
	2018	2017	**2018**	2017
Oil	**$ 5,583,415**	$ 2,339,123	**$ 8,916,697**	$ 4,546,817
Natural gas	**25,131**	73,724	**77,809**	151,475
NGL	**10,369**	6,819	**18,329**	14,119
Total	**$ 5,618,915**	$ 2,419,666	**$ 9,012,836**	$ 4,712,412

Revenue for the three and six months ended June 30, 2018 increased by 132% and 91%, respectively, from the comparable periods in 2017. These increases are attributed to the $14.31/boe and $8.08/boe increases in the Company's combined average realized prices, and increases in production by 76% and 62% during the periods, respectively.

Operating Netback

	Three Months Ended June 30		Six Months Ended June 30	
	2018	2017	**2018**	2017
Operating netback				
Revenue	**$ 5,618,915**	$ 2,419,666	**$ 9,012,836**	$ 4,712,412
Royalties	**995,192**	392,620	**1,509,963**	691,737
Operating costs	**1,061,350**	884,279	**2,222,484**	1,797,820
Transportation costs	**282,534**	153,086	**482,572**	314,349
Operating field netback[1]	**$ 3,279,840**	$ 989,681	**$ 4,797,818**	$ 1,908,505
Realized commodity hedging gain (loss)	**954,002**	106,731	**1,512,884**	146,183
Operating netback[2]	**$ 2,325,838**	$ 1,096,412	**$ 3,284,934**	$ 2,054,688
Operating netback ($/boe)				
Revenue	**$ 58.64**	$ 44.34	**$ 52.09**	$ 44.02
Royalties	**10.39**	7.19	**8.73**	6.46
Operating costs	**$ 11.08**	$ 16.20	**$ 12.85**	$ 16.79
Transportation costs	**2.94**	$ 2.81	**2.78**	$ 2.94
Operating field netback[1]	**$ 34.23**	$ 18.14	**$ 27.73**	$ 17.83
Realized commodity hedging (gain) loss	**9.96**	(1.96)	**8.74**	(1.37)
Operating Netback[2]	**$ 24.27**	$ 20.09	**$ 18.99**	$ 19.19

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 June 30, 2018 were $10.39/boe, representing a 44% increase from the three months ended June 30, 2017. Royalties for the six months ended June 30, 2018 were $8.73/boe, representing a 35% 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 six months ended June 30, 2018 increased on an absolute basis by 20% and 24%, respectively, but decreased on a per boe basis by $5.13 and $3.95, 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 $2.94/boe during the second quarter of 2018, which is a $0.13/boe increase from the comparable quarter in 2017. Transportation costs were $2.78/boe for the six months ended June 30, 2018, which represents a $0.14/boe decrease from the same period in 2017. The small increase in trucking for the three months ended June 30, 2018 is due to increased wait time charges for pipeline deliveries, but the overall year-to-date decrease is a result of reduced infield trucking for six month period.

Operating netback at $24.27/boe for the three months ended June 30, 2018 was 21% higher than the comparable quarter in 2017, mainly due to the 32% increase in the Company's combined average realized prices and higher production rates for the period, as discussed above. For the six months ended

June 30, 2018 operating netback was $18.99/boe, just 1% lower than the same period in 2017. This minor decrease is primarily due to a net $10.11 increase in hedging losses for the six months ending June 30, 2018, compared to the prior period

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 June 30, 2018 and 2017 were $15,621 and $14,995, respectively. For the six months ended June 30, 2018 and 2017, exploration and evaluation expenses were $25,541 and $24,290, respectively.

Depletion and Depreciation

	Three Months Ended June 30		Six Months Ended June 30	
	2018	2017	**2018**	2017
Depletion expense	**$ 1,026,864**	$ 712,112	**$ 1,889,341**	$ 1,396,006
Depreciation expense	**1,369**	1,844	**2,739**	3,688
Total	**$ 1,028,233**	$ 713,956	**$ 1,892,080**	$ 1,399,694
$ per boe	**$ 10.73**	$ 13.08	**$ 10.94**	$ 13.07

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 June 30, 2018 decreased to $10.73/boe from $13.08/boe for the same period in 2017. For the six months ended June 30, 2018, depletion and depreciation expenses decreased to $10.94/boe from $13.07/boe for the same period in 2017. The decreases in depletion expenses for the three and six months ended June 30, 2018 as compared to the same periods in 2017 are 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 June 30		Six Months Ended June 30	
	2018	2017	**2018**	2017
Land and lease	**$ 2,016**	$ 2,016	**$ 5,030**	$ 12,704
Geological and geophysical	**129,764**	81,421	**244,202**	153,649
Drilling and completions	**2,088,803**	81,828	**4,266,217**	159,577
Facilities and infrastructure	**312,294**	496,042	**887,492**	591,891
Total capital expenditures(1)	**$ 2,532,877**	$ 661,307	**$ 5,402,941**	$ 917,821

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

The development capital spent during the first half of 2018 included capital associated with drilling and completing three new wells in the spring of 2018, preparatory work for the company's summer drilling program, and the drilling of the first two wells of the summer program

General and Administrative

	Three Months Ended June 30		Six Months Ended June 30	
	2018	2017	**2018**	2017
Gross general and administrative	**$ 625,635**	$ 445,784	**$ 1,124,171**	$ 824,622
Capitalized general and administrative	**(135,593)**	(86,492)	**(227,660)**	(159,403)
Total	**$ 490,042**	$ 359,292	**$ 896,511**	$ 665,219
$ per boe	**$ 5.11**	$ 6.58	**$ 5.18**	$ 6.21

Gross general and administrative expenses per boe for the three and six months ended June 30, 2018 decreased by 22% and 17% respectively, over the same periods in 2017 due to production growth of the company. On an absolute basis, these expenses increased by $179,851 and $299,549 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 six months ended June 30, 2018, capitalized general and administrative expenses increased by $49,101 and $68,257, respectively, from 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 six monts ended June 30, 2018, the Company recorded total share-based payments of $56,854 and $118,098 respectively, compared to $nil and $1,093 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 second quarter of 2018, $56,854 from the vesting of options in prior fiscal periods.

	Three Months Ended June 30		Six Months Ended June 30	
	2018	2017	**2018**	2017
Share-based payments	**$ 56,854**	$ -	**$ 118,098**	$ 1,093
Capitalized costs	**-**	-	**70,180**	-
Total share-based payments	**$ 56,854**	$ -	**$ 188,278**	$ 1,093

Finance Expense

	Three Months Ended June 30		Six Months Ended June 30	
	2018	2017	**2018**	2017
Interest expense	**$ 586,034**	$ 139,043	**$ 1,082,527**	$ 286,061
Accretion of debt issuance costs	**49,739**	-	**97,190**	-
Amortization of deferred charges	**75,272**	-	**148,965**	-
Accretion of decommissioning liabilities	**34,586**	26,931	**69,172**	53,863
Total	**$ 745,631**	$ 165,974	**$ 1,397,854**	$ 339,924
$ per boe	**$ 7.78**	$ 3.04	**$ 8.08**	$ 3.18

Interest expense for the three and six months ended June 30, 2018 increased by $446,991 and $796,466 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 six months ended June 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				2016	
	Jun. 30 Q2(1)	Mar. 31 Q1(2)	Dec. 31 Q4(3)	Sep. 30 Q3(4)	Jun. 30 Q2(5)	Mar. 31 Q1(6)	Dec. 31 Q4(7)	Sep. 30 Q3(8)
Average daily production (boe/d)	1,053	858	770	681	600	583	590	518
Petroleum and natural gas revenue	5,618,915	3,393,921	3,528,565	2,733,656	2,419,666	2,292,746	2,206,835	1,630,105
Petroleum and natural gas Operating Field Netback(9)	3,279,840	1,517,979	1,847,185	1,176,204	989,681	958,276	860,849	779,966
Funds flow from/used in operations(10)	1,251,089	99,720	714,801	657,840	598,078	505,331	273,181	345,007
Per share, basic and diluted	0.01	0.00	0.01	0.01	0.01	0.01	0.00	0.00
Net income (loss)	(2,253,163)	(2,389,393)	(3,308,520)	(142,254)	(206,724)	(138,678)	(620,027)	(413,340)
Basic and diluted income (loss) per share	(0.03)	(0.03)	(0.04)	(0.00)	(0.00)	(0.00)	(0.01)	0.00
Combined average realized price ($/boe)	58.64	43.96	49.80	43.62	44.34	43.68	40.63	34.19
Operating netback ($/boe)(11)	24.27	12.42	23.29	19.28	20.09	18.26	15.85	16.36

Notes:

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

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

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

(4) 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.

(5) 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.

(6) 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.

(7) 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.

(8) The increases in revenue and netbacks, and the resulting reduced loss in this quarter over the previous quarter is due primarily to an 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

	August 22, 2018	**June 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 August 22, 2018:

Exercise Price	Grant Date	Expiry Date	Balance Outstanding August 22, 2018	Balance Exercisable August 22, 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 June 30, 2018 and December 31, 2017 were $23,734,580 and $18,558,361 respectively, representing an increase in net debt of $5,176,219.

a) Financing

The Company's net cash provided by financing activities during the three and six months ended June 30, 2018 were nil and $3,645,010 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 (as further disclosed in Note 12 of the Company's audited annual financial statements for the quarter ended March 31, 2018). These funds were used for expenditures in the Company's fall drill program.

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 June 30, 2018 the Company has drawn US$18.0 million (CAD$23,637,600). 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 June 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,

   plus

   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, plus
   (ii) Provisions for taxes based on income (including margin or gross receipts taxes), plus
   (iii) Total depreciation and amortization expense, plus
   (iv) Impairment or asset write-down expense, plus
   (v) Accretion of asset retirement obligation and debt issuance costs, plus
   (vi) Share-based compensation expense, plus

(vii) Non-cash losses resulting from the mark-to-market exposure of outstanding swaps and unrealized foreign exchange exposure, plus

(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),

minus

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 June 30, 2018 the company has met all of the financial and performance covenants in effect, as follows:

Ratio			**Required**	**Actual June 30, 2018**	
1.	Interest Coverage Ratio	Greater than	2.00	3.13	
2.	Total Leverage Ratio	Less than	5.25	3.26	
3.	Minimum Average Production	Greater than	750	1,053	Boe/d
4.	Proved Developed Producing Coverage Ratio	Greater than	1.00	1.02	
5.	Total Proved Reserves Coverage Ratio	Greater than	1.50	2.54	

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 June 30, 2018, the gross balance of the Term Loan was $23,637,600 (US$18,000,000), exclusive of the debt issuance costs. The Term Loan matures on September 15, 2022.

		2018	2019	2020	2021	2022	2023	Total
Office Rental	$	57,782	138,676	138,676	138,676	138,676	57,782	670,265
Term Loan		-	-	-	-	23,637,600	-	23,637,600
Term Loan Interest		868,682	1,737,364	1,737,364	1,737,364	1,232,206	-	7,312,979
	$	926,464	1,876,039	1,876,039	1,876,039	25,008,482	57,782	31,620,844

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	
	June 30, 2018	December 31, 2017
Accounts receivable		
Marketing receivables	**$ 1,779,054**	$ 1,284,474
Trade receivables	**49,496**	76,437
Receivables from joint venture	**54**	7,297
Reclamation deposits	**115,535**	115,535
Total	**$ 1,944,139**	$ 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 manages liquidity risk by anticipating operating, investing and financing activities and ensuring that it will have sufficient liquidity to meet its liabilities when they become due, under both normal and stressed conditions, without incurring unacceptable losses or risking damage to the Company. The Company prepares expenditure budgets on a quarterly and annual basis which are regularly monitored and updated when necessary in order to review debt forecasts and working capital requirements.

At June 30, 2018, the Company had net debt (current assets less current liabilities excluding fair value of financial instruments, and outstanding Term Loan) of $23,734,580 (December 31, 2017 - $18,558,361), which includes Term Loan of $23,637,600 (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 $240,000 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 $230,000 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 June 30				**Six Months Ended June 30**		
		2018		2017		**2018**		2017
Cash provided by operating activities	**$**	**413,990**	$	612,221	**$**	**(193,833)**	$	793,063
Less: Change in non-cash working capital		**(837,099)**		14,143		**(1,544,643)**		(310,346)
Funds flow from operations	**$**	**1,251,089**	$	598,078	**$**	**1,350,810**	$	1,103,409
Per share, basic and diluted	**$**	**0.01**	$	0.01	**$**	**0.02**	$	0.01

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		
		June 30, 2018		December 31, 2017
Current assets[(1)]	**$**	**2,726,594**	$	2,955,446
Current liabilities[(2)]		**(2,823,574)**		(2,645,307)
Term Loan		**(23,637,600)**		(18,868,500)
Net debt	**$**	**(23,734,580)**	$	(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.

MANAGEMENT'S REPORT

To the Shareholders of Hemisphere Energy Corporation:

Management is responsible for the preparation of the financial statements and the consistent presentation of all other financial information that is publicly disclosed. The financial statements have been prepared in accordance with the accounting policies detailed in the notes to the financial statements and in accordance with IFRS and include estimates and assumptions based on management's best judgment. Management maintains a system of internal controls to provide reasonable assurance that assets are safeguarded and that relevant and reliable financial information is produced in a timely manner.

The accompanying unaudited interim condensed financial statements have not been reviewed by the Company's auditors.

The Audit Committee, consisting of independent members of the Board of Directors, has reviewed financial statements with management. The Board of Directors has approved the financial statements on the recommendation of the Audit Committee.

Vancouver, British Columbia
August 22, 2018

(signed) *"Don Simmons"*	(signed) *"Dorlyn Evancic"*
Don Simmons, President & CEO	Dorlyn Evancic, Chief Financial Officer

CONDENSED STATEMENTS OF FINANCIAL POSITION

(Expressed in Canadian dollars)
(Unaudited)

	Note		June 30, 2018		December 31, 2017
Assets					
Current assets					
Cash and cash equivalents		$	**713,302**	$	1,372,991
Accounts receivable			**1,828,604**		1,368,208
Prepaid expenses			**184,689**		214,247
			2,726,595		2,955,446
Non-current assets					
Reclamation deposits	8		**115,535**		115,535
Exploration and evaluation assets	6		**6,744,316**		4,894,108
Property and equipment	7		**41,781,312**		39,894,023
Deferred charges	10		**936,037**		1,210,691
Total assets		$	**52,303,795**	$	49,069,803
Liabilities					
Current liabilities					
Accounts payable and accrued liabilities		$	**2,823,574**	$	2,645,307
Fair value of financial instruments	3(c)		**3,045,900**		1,579,726
			5,869,474		4,225,033
Non-current liabilities					
Term loan	10		**22,131,715**		17,465,518
Fair value of financial instruments	3(c)		**1,970,018**		843,556
Decommissioning obligations	8		**6,427,282**		6,176,112
			36,398,489		28,710,219
Shareholders' Equity					
Share capital	11		**54,724,441**		54,724,441
Contributed surplus			**838,053**		649,775
Warrant reserve	11(c)		**1,043,136**		1,043,136
Deficit			**(40,700,324)**		(36,057,768)
Total shareholders' equity			**15,905,306**		20,359,584
Total liabilities and shareholders' equity		$	**52,303,795**	$	49,069,803

Commitments (Note 12)
Subsequent events (Note 14)

The accompanying notes are an integral part of these unaudited interim condensed financial statements.

CONDENSED STATEMENTS OF COMPREHENSIVE INCOME

(Expressed in Canadian dollars)
(Unaudited)

	Note	Three Months Ended June 30 2018	Three Months Ended June 30 2017	Six Months Ended June 30 2018	Six Months Ended June 30 2017
Revenue					
Oil and natural gas revenue		**$ 5,618,915**	$ 2,419,666	**$ 9,012,836**	$ 4,712,412
Royalties		**(995,192)**	(392,620)	**(1,509,963)**	(691,737)
		4,623,723	2,027,046	**7,502,873**	4,020,675
Realized gain on financial instruments		**(954,002)**	106,731	**(1,512,884)**	146,183
Unrealized (loss) gain on financial instruments	3(c)	**(1,835,467)**	(48,919)	**(2,592,636)**	30,130
Net revenue		**1,834,254**	2,084,858	**3,397,353**	4,196,988
Expenses					
Production and operating		**1,343,884**	1,037,364	**2,705,056**	2,112,169
Exploration and evaluation	7	**15,621**	14,995	**25,541**	24,290
Depletion and depreciation	8	**1,028,234**	713,956	**1,892,080**	1,399,694
General and administrative		**490,041**	359,292	**896,511**	665,219
Share-based payments	13(b)	**56,854**	-	**118,097**	1,093
		2,934,634	2,125,607	**5,637,285**	4,202,465
Results from operating activities		**(1,100,380)**	(40,750)	**(2,239,932)**	(5,478)
Finance expense	10	**(745,631)**	(165,974)	**(1,397,854)**	(339,924)
Foreign exchange gain (loss)		**(407,152)**	-	**(1,004,770)**	-
Net loss and comprehensive loss for the period		**$ (2,253,163)**	$ (206,724)	**$ (4,642,556)**	$ (345,402)
Net loss per share Basic and diluted	10(d)	**$ (0.03)**	$ (0.00)	**$ (0.05)**	$ (0.00)

The accompanying notes are an integral part of these unaudited interim condensed financial statements.

CONDENSED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

(Expressed in Canadian dollars)
(Unaudited)

	Note	Number common shares		Share Capital		Contributed Surplus		Warrant Reserve		Deficit		Total Equity
Balance, December 31, 2016		**85,745,102**	**$**	**53,838,621**	**$**	**1,192,106**	**$**	**-**	**$**	**(33,136,591)**	**$**	**21,894,136**
Flow-through share issuance		4,048,200		1,133,496		-		-		-		1,133,496
Share issuance costs		-		(85,748)		-		-		-		(85,748)
Flow-through share premium		-		(161,928)		-		-		-		(161,928)
Share-based payments	11(b)	-		-		332,669		-		-		332,669
Expiry of stock options		-		-		(875,000)		-		875,000		-
Warrant Issue – net deferred tax	11(c)	-		-		-		1,043,136		-		1,043,136
Net loss for the year		-		-		-		-		(3,796,175)		(3,796,175)
Balance, December 31, 2017		**89,793,302**	**$**	**54,724,441**	**$**	**649,775**	**$**	**1,043,136**	**$**	**(36,057,768)**	**$**	**20,359,584**
Balance, December 31, 2017		**89,793,302**	**$**	**54,724,441**	**$**	**649,775**	**$**	**1,043,136**	**$**	**(36,057,768)**	**$**	**20,359,584**
Share-based payments		-		-		188,278		-		-		188,278
Net loss for the year		-		-		-		-		(4,642,556)		(4,647,556)
Balance, June 30, 2018		**89,793,302**	**$**	**54,724,441**	**$**	**838,053**	**$**	**1,043,136**	**$**	**(40,700,324)**	**$**	**15,905,306**

Comparison with six months ended, 2017:

	Note	Number common shares		Share Capital		Contributed Surplus		Warrant Reserve		Deficit		Total Equity
Balance, December 31, 2016		**85,745,102**	**$**	**53,838,621**	**$**	**1,192,106**	**$**	**-**	**$**	**(33,136,591)**	**$**	**21,894,136**
Non-flow-through share		-		-		-		-		-		465,405
Flow-through share issuance		4,048,200		1,133,496		-		-		-		576,030
Share issuance costs		-		(97,508)		-		-		-		(29,524)
Flow-through share premium				(161,928)		-		-		-		-
Exercise of stock options		-		-		(5,830)		-		-		8,000
Share-based payments	11(b)	-		-		-		-		-		-
Expiry of stock options		-		-		(1,364,195)		-		1,364,195		114,376
Net loss for the period		-		-		114,376		-		(1,647,281)		(343,174)
Balance, June 30, 2017		**81,905,988**	**$**	**53,108,812**	**$**	**1,206,221**	**$**	**-**	**$**	**(32,115,194)**	**$**	**22,199,839**

The accompanying notes are an integral part of these unaudited interim condensed financial statements.

CONDENSED STATEMENTS OF CASH FLOWS

(Expressed in Canadian dollars)
(Unaudited)

	Three Months Ended June 30		Six Months Ended June 30	
	2018	2017	**2018**	2017
Operating activities				
Net income (loss) for the period	**$ (2,253,163)**	$ (206,724)	**$ (4,642,556)**	$ (345,402)
Items not affecting cash:				
Accretion of debt issuance costs	**49,739**	-	**97,190**	-
Accretion of decommissioning costs	**34,586**	26,931	**69,172**	53,863
Amortization of deferred charges	**75,272**	-	**148,965**	-
Depletion and depreciation	**1,028,233**	713,956	**1,892,079**	1,399,694
Exploration and evaluation expense	**15,621**	14,995	**25,541**	24,290
Share-based payments	**56,854**	-	**118,097**	1,093
Unrealized loss (gain) on financial instruments	**1,835,467**	48,919	**2,592,636**	(30,130)
Unrealized loss on foreign exchange	**408,480**	-	**1,049,686**	-
	1,251,089	598,078	**1,350,810**	1,103,409
Changes in non-cash working capital	**(837,100)**	14,143	**(1,544,643)**	(310,346)
Cash provided by (used in) operating activities	**413,989**	612,221	**(193,833)**	793,063
Investing activities				
Property and equipment expenditures	**(756,861)**	(572,910)	**(3,289,522)**	(756,201)
Exploration and evaluation expenditures	**(1,776,014)**	(88,396)	**(2,113,419)**	(161,619)
Changes in non-cash working capital	**(445,634)**	172,082	**1,292,073**	(127,640)
Cash used in investing activities	**(2,978,509)**	(489,224)	**(4,110,868)**	(1,045,460)
Financing activities				
Shares issued for cash, net of issue costs	-	1,035,987	-	1,035,987
Change in bank indebtedness	-	(1,158,982)	-	(783,589)
Proceeds from term loan	-	-	**3,645,010**	-
Cash provided by (used in) financing activities	-	(122,995)	**3,645,010**	252,398
Net change in cash	**(2,564,519)**	-	**(659,689)**	-
Cash, beginning of period	**3,277,821**	-	**1,372,991**	-
Cash , end of period	**$ 713,302**	$ -	**$ 713,302**	$ -

Supplemental cash flow information (Note 12)

The accompanying notes are an integral part of these unaudited interim condensed financial statements.

NOTES TO THE INTERIM CONDENSED FINANCIAL STATEMENTS

For the three and six months ended June 30, 2018 and 2017

(Expressed in Canadian Dollars)

1. Nature and Continuance of Operations

Hemisphere Energy Corporation (the "Company") was incorporated under the laws of British Columbia on March 6, 1978. The Company's principal business is the acquisition, exploration, development and production of petroleum and natural gas interests in Canada. It is a publicly traded company listed on the TSX Venture Exchange under the symbol "HME". The Company's head office is located at Suite 2000, 1055 West Hastings Street, Vancouver, British Columbia, Canada V6E 2E9.

2. Basis of Presentation

(a) Statement of compliance

These unaudited interim condensed financial statements ("Financial Statements") have been prepared in accordance with International Accounting Standard ("IAS") 34 – Interim Financial Reporting using accounting policies consistent with the International Financial Reporting Standards ("IFRS"), as issued by the International Accounting Standards Board ("IASB"). These Financial Statements do not include all of the information required for full annual financial statements and should be read in conjunction with the Company's audited annual financial statements for the year ended December 31, 2017.

These financial statements were authorized for issuance by the Board of Directors on August 22, 2018.

(b) Basis of presentation

These Financial Statements have been prepared on a historical cost basis, except for financial instruments and share-based payments, which are stated at their fair values.

(c) Functional and presentation currency

These Financial Statements are presented in Canadian dollars, which is the Company's functional currency.

(d) Use of estimates and judgments

The preparation of these Financial Statements in conformity with IFRS requires management to make judgments, estimates and assumptions that may affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may materially differ from these estimates.

Estimates and their underlying assumptions are reviewed on an ongoing basis and are based on management's experience and other factors, including extectation of future events that are believed to be reasonable under the circumstances. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected.

(e) Summary of significant accounting policies

These financial statements have been prepared in accordance with IFRS and follow the same accounting policies as described in Note 3 of the Company's audited annual financial statements for the year ended December 31, 2017. There have been no changes to the Company's accounting policies since the Company's audited annual financial statements for the year ended December 31, 2017 were issued.

At the date of these financial statements the standards and interpretations listed below were issued but not yet effective. The adoption of these standards may result in future changes to existing accounting policies and disclosures.

a) IFRS 15 - In May 2014, the IASB issued IFRS 15 "Revenue from Contracts with Customers," which replaces IAS 18 "Revenue," IAS 11 "Construction Contracts," and related interpretations. The standard is required to be adopted either retrospectively or using a modified transition approach for fiscal years 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 and applied IFRS 15 to all of its contracts with customers using the modified respective 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. As a result, no adjustments were required in the January 1, 2018 opening balance sheet.

The adoption of IFRS 15 does result in new disclosure requirements contained in note 5 of these condensed consolidated interim financial statements. The Company primarily earns revenue from sales of the production of light oil, heavy oil, natural gas and natural gas liquids. The Company may earn revenue from fees charged to third parties for processing and other services (i.e., gas and other product processing, etc.) provided at locations where the Company has processing facilities, however, the Company does not currently conduct any third party processing.

Revenues from the sale of crude oil, natural gas liquids and natural gas is recognized based on the consideration specified in contracts with customers. The Company recognizes revenue when it transfers control of the product to the customer, which is generally when legal title passes to the customer which is when it is physically transferred to the pipeline or other transportation method agreed upon and collection is reasonably assured. Any revenues from processing activities are recognized over time as processing occurs, and are generally billed monthly.

The Company evaluates its arrangements with third parties and partners to determine if the Company is acting as the principal or as an agent. The Company is considered the principal in a transaction when it has primary responsibility for the transaction. If the Company acts in the capacity of an agent rather than as a principal in a transaction, then the revenue is recognized on a net basis, only reflecting the fee, if any, realized by the Company from the transaction

b) IFRS 9 - In July 2014, the IASB finalized the remaining elements of IFRS 9 – Financial Instruments, which includes new requirements for the classification and measurement of financial assets, amends the impairment model and outlines a new general hedge accounting standard.

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 adoption of IFRS 9 had no material impact to the Company's condensed consolidated interim 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.

The following table shows the original measurement categories under IAS 39 and the new measurement categories under IFRS 9 as at January 1, 2018 for each class of the Company's financial assets and financial liabilities:

	Measurement category	
Financial instrument	IAS 39	IFRS 9
Cash and cash equivalents	Loans and receivables	Amortized cost
Accounts receivable	Loans and receivables	Amortized cost
Financial derivative contracts	Fair value via profit or loss	Fair value via profit or loss
Accounts payable and accrued liabilities	Financial liabilities at amortized cost	Amortized cost
Term loan	Financial liabilities at amortized cost	Amortized cost

There were no adjustments to the carrying amounts of the Company's financial instruments as a result of the change in classification from IAS 39 to IFRS 9. The Company does not apply hedge accounting.

IFRS 9 replaces the "incurred loss" model in IAS 39 with an "expected credit loss" ("ECL") model. The Company measures loss allowances at an amount equal to expected lifetime ECLs. Lifetime ECLs are the anticipated ECLs that result from all possible default events over the expected life of a financial asset. ECLs are a probability-weighted estimate of credit loss and are discounted at the effective interest rate of the related financial asset. The application of the new expected credit loss model did not have a significant impact on the Company's financial assets.

c) In January 2017, the IASB issued IFRS 16 Leases, which replaces IAS 17 Leases. For lessees applying IFRS 16, a single recognition and measurement model for leases would apply, with required recognition of assets and liabilities for most leases. The standard will come into effect for annual periods beginning on or after January 1, 2019, with earlier adoption permitted if the entity is also applying IFRS 15 Revenue from Contracts with Customers. The Company is currently identifying contracts that will be identified as leases and evaluating the impact of the standard on the consolidated financial statements.

There are no other standards and interpretations in issue but not yet adopted that are expected to have a material effect on the reported earnings or net assets of the Company.

3. Financial Risk Management

The Company's activities expose it to a variety of financial risks that arise as a result of its exploration, development, production and financing activities such as credit risk, liquidity risk and market risk. This note presents information about the Company's exposure to each of these risks. Management sets controls to manage such risks and monitors them on an ongoing basis pertaining to market conditions and the Company's activities.

(a) Credit risk

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its 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:

		June 30, 2018		December 31, 2017
Accounts receivable				
Marketing receivables	**$**	**1,779,054**	$	1,284,474
Trade receivables	**$**	**49,496**	$	76,437
Receivables from joint ventures		**54**		7,297
Reclamation deposits		**115,535**		115,535
	$	**1,944,139**	$	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.

(b) Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. The Company's approach to managing liquidity risk is to ensure, as far as possible, that it will have sufficient liquidity to meet its liabilities when they become due, under both normal and stressed conditions, without incurring unacceptable losses or risking damage to the Company.

At June 30, 2018 the Company had net debt (current assets less current liabilities excluding fair value of financial instruments, and outstanding Term Loan) of $23,734,580 (December 31, 2017 - $18,558,361), which includes Term Loan (Note 12) of $23,637,600 (December 31, 2017 - $18,868,500). The Company funds its operations through production revenue and the Term Loan (Note 10).

(c) Market risk

Market risk is the risk that changes in market prices, such as foreign exchange rates, other 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.

(i) 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 $240,000 effect on net loss and comprehensive loss.

(ii) Foreign currency risk
The Company's functional and reporting currency is the Canadian dollar. The Company does not sell or transact in any foreign currency; except; i) the Company's commodity prices are largely denominated in United States dollars ("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. ii) the Company's Term Loan is denominated in USD , and as 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 $50,000 effect on the annual net loss and comprehensive loss.

(iii) 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 does have hedging swap agreements in place as further disclosed within this document and the financial statements.

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

Product	Type	Volume	Price	Index	Term	Jun.30, 2018 Fair Value
Crude oil	Swap(1)	150 bbl/d	US$54.65	WTI-NYMEX	November 1, 2017 – June 30, 2018	-
Crude oil	Swap	300 bbl/d	US$50.67	WTI-NYMEX	January 1, 2018 – December 31, 2018	1,944,611
Crude oil	Swap	100 bbl/d	US$21.90	WCS	April 1, 2018 – September 30, 2018	(5,496)
Crude oil	Swap	400 bbl/d	US$18.45	WCS	May 1, 2018 – September 30, 2018	(132,528)
Crude oil	Option(1)	150 bbl/d	US$54.65	WTI-NYMEX	July 1, 2018 – February 28, 2019	732,401
Crude oil	Swap	250 bbl/d	US$50.67	WTI-NYMEX	January 1, 2019 – December 31, 2019	1,264,977
Crude oil	Collar	130 bbl/d	US$40.00-US$74.50	WTI-NYMEX	March 1, 2019 – December 31, 2019	123,206
Crude oil	Swap	200 bbl/d	US$50.67	WTI-NYMEX	January 1, 2020 – August 31, 2020	698,416
Crude oil	Collar	120 bbl/d	US$40.00-US$68.25	WTI-NYMEX	January 1, 2020 – December 31, 2020	184,060
Crude oil	Collar	200 bbl/d	US$40.00-US$67.05	WTI-NYMEX	September 1, 2020 – December 31, 2020	98,971
Crude oil	Collar	275 bbl/d	US$40.00-US$65.50	WTI-NYMEX	January 1, 2021 – March 31, 2021	107,301
					Total	$5,015,918

Note:
(1) The counter-party to this contract has enacted their one time option to extend a swap on 150 bbl/d of crude oil at US$54.65 for the term indicated as of June 30, 2018.

At June 30, 2018 the commodity contracts were fair valued as a liability of $5,015,918 recorded on the balance sheet (current portion $3,045,900), and an unrealized loss for the three and six month periods of $1,835,467 and $2,592,636 respectively (June 30, 2017 – loss $48,919 and gain 30,130 respectively).

(iv) Other price risk

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

4. Capital Management

The Company manages its capital with the following objectives:

(a) To ensure sufficient financial 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

(b) To 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 Company and industry in general. The capital structure of the Company is composed of shareholders' equity and net debt. The Company may manage its capital structure by issuing new shares, repurchasing outstanding shares, obtaining additional financing from the Company's credit facilities, issuing new debt instruments or other financial or equity-based instruments, adjusting capital spending or disposing of assets. The capital structure is reviewed on an ongoing basis.

5. Revenue

The Company sells its production pursuant to variable-price contracts. The transaction price for variable-price contracts is based on a benchmark commodity price, adjusted for quality, location or other factors whereby each component of the pricing formula can be either fixed or variable, depending on the contract terms. Under the contracts, the Company is required to deliver variable volumes of heavy oil, natural gas or natural gas liquids to the contract counterparty.

Production revenue is recognized when the Company gives up control of the unit of production at the delivery point agreed to under the terms of the contract. The amount of production revenue recognized is based on the agreed transaction price and the volumes delivered. Any variability in the transaction price relates specifically to the Company's efforts to transfer production and therefore the resulting revenue is allocated to the production delivered in the period to which the variability relates. The Company does not have any factors considered to be constraining in the recognition of revenue with variable pricing factors. Production revenues are normally collected on the business day nearest the 25th day of the month following production.

The Company’s production revenues were primarily generated in its core areas of the Mannville oil play in the Atlee Buffalo and Jenner areas of southeastern Alberta. The Company’s customers are oil and natural gas marketers and joint operations partners in the oil and natural gas business and are subject to normal credit risks. Concentration of credit risk is mitigated by marketing production to numerous oil and natural gas marketers under customary industry sale and payment terms. As at June 30 2018, production revenue was sold to customers, of which three customers account for $1,779,054 of the accounts receivable at June 30 2018.

The following table presents the Company’s total revenues disaggregated by revenue source:

	Three Months Ended June 30		Six Months Ended June 30	
	2018	2017	**2018**	2017
Oil	**$ 5,583,415**	$ 2,339,123	**$ 8,916,697**	$ 4,546,817
Natural gas	**25,131**	73,724	**77,809**	151,475
NGL	**10,369**	6,819	**18,329**	14,119
Total	**$ 5,618,915**	$ 2,419,666	**$ 9,012,836**	$ 4,712,411

6. Exploration and Evaluation Assets

Exploration and evaluation assets consist of the Company’s exploration projects, which are pending the determination of Proved and Probable reserves. A transfer from exploration and evaluation assets to property and equipment is made when reserves are assigned or the exploration project has been completed. For the period ended June 30, 2018, the Company had $237,670 transfers (June 30, 2017 - $nil) to property and equipment, capitalized general and administrative expenses of $136,625 (June 30, 2017 - $123,896) to exploration and evaluation assets, and recognized exploration and evaluation expense of $25,541 (June 30, 2017 - $24,290).

Cost		
Balance, December 31, 2016	$	3,260,407
Additions		4,108,542
Exploration and evaluation expense		(576,586)
Transfer to property and equipment		(1,898,255)
Balance, December 31, 2017	$	4,894,108
Additions		2,113,419
Exploration and evaluation expense		(25,541)
Transfer to property and equipment		(237,670)
Balance, June 30, 2018	**$**	**6,744,316**

7. Property and Equipment

Cost		Petroleum and Natural Gas		Other Equipment		Total
Balance, December 31, 2016	$	67,142,548	$	114,492	$	67,257,040
Additions		4,580,698		-		4,580,698
Increase in decommissioning obligations		1,171,704		-		1,171,704
Capitalized share-based payments		99,161		-		99,161
Transfer from exploration and evaluation assets		1,898,255		-		1,898,255
Balance, December 31, 2017	$	74,892,367	$	114,492	$	75,006,860
Additions		3,289,522		-		3,289,522
Increase in decommissioning obligations		181,998		-		181,998
Capitalized share-based compensation		70,180		-		70,180
Transfer from exploration and evaluation assets		237,670		-		237,670
Balance, June 30, 2018	**$**	**78,671,738**	**$**	**114,492**	**$**	**78,786,229**
Accumulated Depletion, Depreciation, Amortization and Impairment Losses						
Balance, December 31, 2016		31,929,680		85,316		32,014,996
Depletion and depreciation for the year		3,090,462		7,377		3,097,839
Balance, December 31, 2017	**$**	**35,020,142**	$	**92,693**	$	**35,112,835**
Depletion and depreciation for the period		1,889,341		2,740		1,892,080
June 30, 2018	**$**	**36,909,484**	**$**	**95,434**	**$**	**37,004,917**
Net Book Value						
December 31, 2017	$	39,872,225	$	21,978	$	39,894,023
June 30, 2018	**$**	**41,762,254**	**$**	**19,058**	**$**	**41,781,312**

The Company's additions for property and equipment included capitalized general and administrative expenses of $91,035 for the period ended June 30, 2018 (June 30, 2017 - $35,507).

The calculation of depletion at June 30, 2018 includes estimated future development costs of $31,944,000 (December 31, 2017 - $34,424,000) associated with the development of the Company's Proved plus Probable reserves.

8. Decommissioning Obligations

The Company's decommissioning obligation is estimated based on its net ownership interest in all wells and facilities, estimated costs to reclaim and abandon these wells and facilities, and the estimated timing of the costs to be incurred in future years. The Company uses Alberta Energy Regulator guidelines for determining abandonment and reclamation estimates.

The Company estimates the total undiscounted and inflated amount of cash flows required to settle its decommissioning obligations as at June 30, 2018 is $6,941,336 (December 31, 2017 - $6,746,366). These payments are expected to be made over the next 37 years with the majority of costs to be incurred between 2025 and 2054. The discount factor, being the risk-free rate related to the liability, is 2.24% (December 31, 2017 - 2.24%). Inflation of 1.80% (December 31, 2017 – 1.80%) has also been factored into the calculation. The Company also has $115,535 (December 31, 2017 - $115,535) in various reclamation bonds for its properties held by the Alberta Energy Regulator and British Columbia Ministry of Energy, Mines and Petroleum Resources.

			June 30, 2018		December 31, 2017
Decommissioning obligations, beginning of period	discounted	**$**	**6,176,112**	$	4,896,681
Increase in estimated future obligations			**181,998**		847,114
Change in estimate			**-**		324,591
Decommissioning obligation expenditures			**-**		-
Accretion expense			**69,172**		107,727
Decommissioning obligations, end of period	discounted	**$**	**6,427,282**	$	6,176,112

9. Finance Income and Expense

	Three Months Ended June 30				**Six Months Ended June 30**			
		2018		2017		**2018**		2017
Finance expense:								
Cash interest expense	**$**	**586,034**	$	139,043	**$**	**1,082,527**	$	286,061
Amortization of deferred charges		**75,272**		-		**148,965**		-
Accretion of debt issuance costs		**49,739**		-		**97,190**		-
Accretion of decommissioning liabilities		**34,586**		26,931		**69,172**		53,863
Total	**$**	**745,632**	$	165,974	**$**	**1,397,855**	$	339,924

10. 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 obtain an 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 June 30, 2018 the Company has drawn US$18.0 million (CAD$23,637,600). 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 effective interest rate is 10.66%.

	Term Loan	Deferred Charges	Total
Principal amount of Term Loan issued	$ 22,301,510	$ -	$ 22,301,510
Foreign exchange adjustment	1,294,140	-	1,294,139
Debt issuance costs	(897,009)	(456,738)	(1,353,747)
Value allocated to warrants	(712,853)	(716,101)	(1,428,954)
Amortization of deferred charges	-	236,801	236,801
Accretion of debt issuance costs	145,928	-	145,928
Balance, end of period – liability (asset)	**$ 22,131,715**	**$ (936,037)**	**$ 21,195,677**

The Company has recognized a portion of the debt issuance costs and value allocated to the warrants (Note 13(c)) against the Term Loan based on the proportion of the facility drawn, with the balance included in deferred charges. The portion recognized against the Term Loan will be accreted using the effective interest method (refer to effective interest rate above) through finance expense while the deferred charge balance is being straight-line amortized over the five-year term. As future draws are made under the Term Loan, the unamortized proportion of the deferred charges will be transferred against the debt obligation and accreted also using the effective interest method. For the six months ended June 30, 2018, $125,690 of the deferred charges balance was transferred to debt issuance costs.

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. This ratio is calculated using amounts from the reporting quarter only.

   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, whereas EBITDAX from the reporting quarter is factored by four.

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).

   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), plus
(iii) Total depreciation and amortization expense, plus
(iv) Impairment or asset write-down expense, plus
(v) Accretion of asset retirement obligation and debt issuance costs, plus
(vi) Share-based compensation expense, plus
(vii) Non-cash losses resulting from the mark-to-market exposure of outstanding swaps and unrealized foreign exchange exposure, plus
(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),

minus
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 June 30, 2018 the company has met all of the financial and performance covenants in effect as follows:

Ratio			**Required**	**Actual June 30, 2018**
1.	Interest Coverage Ratio	Greater than	2.00	3.13
2.	Total Leverage Ratio	Less than	5.25	3.26
3.	Minimum Average Production - boe/d	Greater than	750	1,053
4.	Proved Developed Producing Coverage Ratio	Greater than	1.00	1.02
5.	Total Proved Reserves Coverage Ratio	Greater than	1.50	2.54

11. Share Capital

(a) Authorized

Unlimited number of common shares without par value.

Issued and outstanding

As at June 30, 2018, the Company had 89,793,302 common shares issued and outstanding.

No shares were issued during the period ended June 30, 2018.

During the year ended December 31, 2017, the following share transactions occurred:

(i) On April 27, 2017, the Company closed a non-brokered private placement offering and issued 4,048,200 flow-through shares at a price of $0.28 per share, which were issued on a Canadian Development Expense flow-through basis pursuant to the provisions of the Income Tax Act (Canada) for gross proceeds of Company of $1,133,496

(b) Stock options

The Company has a stock option plan in place and is authorized to grant stock options to officers, directors, employees and consultants whereby the aggregate number of shares reserved for issuance may not exceed 10% of the issued shares at the time of grant and 5% of the issued shares to each optionee. Stock options are non-transferable and have a maximum term of five years. Stock options terminate no later than 90 days (30 days for investor-related services) upon termination of employment or employment contract and one year in the case of retirement, death or disability. The grant price is determined using the closing price of the Company's shares from the day prior to the grant.

Details of the Company's stock options as at June 30, 2018 are as follows:

			Changes in the Period				
Exercise Price	Expiry Date	Balance Outstanding December 31, 2017	Granted	Exercised	Expired/ Cancelled	Balance Outstanding June 30, 2018	Balance Exercisable June 30, 2018
$0.24	29-Jan-20	1,075,000	-	-	-	1,075,000	1,075,000
$0.39	1-Mar-20	100,000	-	-	-	100,000	100,000
$0.08	11-Feb-21	1,685,000	-	-	-	1,685,000	1,685,000
$0.08	12-Feb-21	125,000	-	-	-	125,000	125,000
$0.25	21-Sep-22	5,034,000	-	-	-	5,034,000	1,678,000
$0.28	2-Oct-22	150,000	-	-	-	150,000	50,000
$0.25	1-Jan-23	-	250,000	-	-	250,000	83,333
		8,169,000	250,000	-	-	8,419,000	4,796,333
Weighted-average exercise price		$0.21	$0.2	-	-	$0.21	$0.19

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 six monts ended June 30, 2018, the Company recorded total share-based payments of $56,854 and $118,097 respectively, compared to $nil and $1,093 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 second quarter of 2018, $56,854 from the vesting of options in prior fiscal periods.

(c) Share purchase warrants

On September 15, 2017, the Company issued 13,750,000 warrants to a third-party lender in conjunction with its Term Loan (Note 10). Each warrant entitles the holder to purchase one common share of Hemisphere at an exercise price of $0.28 per share prior to September 15, 2022. The exercise price of the warrants represented a 40% premium to the 30-day volume weighted average price ("VWAP") of Hemisphere's common shares at market close on September 14, 2017. The warrants are subject to a forced exercise clause which applies upon a 30-day VWAP equaling or exceeding $1.40 per share. The warrants are non-transferable.

The Company ascribed a value to the warrants of $1,428,954 by comparing the fair value of the Term Loan both with and without the warrant feature determining the difference in value to be related to the warrants. The effective rates have been disclosed in Note 12. Further, a deferred tax liability of $385,818 was incurred with regard to the warrants that is applied against the recorded warrant reserve and also recovered against the net loss.

As at June 30, 2018, the Company had 13,750,000 outstanding and exercisable share purchase warrants.

(d) Loss per share

		Three Months Ended June 30				**Six Months Ended June 30**		
		2018		2017		**2018**		2017
Loss for the period	**$**	**(206,724)**	$	(206,724)	**$**	**(345,402)**	$	(345,402)
Weighted average number of common shares outstanding, basic		**89,793,302**		86,946,216		**89,793,302**		88,361,894
Dilutive stock options		**-**		-		**-**		-
Weighted average number of common shares outstanding, diluted		**89,793,302**		86,946,216		**89,793,302**		88,361,894
Loss per share, basic and diluted	**$**	**(0.03)**	$	(0.00)	**$**	**(0.05)**	$	(0.00)

For the three and six months ended June 30, 2018, the Company incurred a loss; therefore, dilutive stock options were nil (three and six months ended June 30, 2017 – nil).

12. Commitment

		2018	2019	2020	2021	2022	2023	Total
Office Rental	$	57,782	138,676	138,676	138,676	138,676	57,782	670,265
Term Loan		-	-	-	-	23,637,600	-	23,637,600
Term Loan Interest		868,862	1,737,364	1,737,364	1,737,364	1,232,206	-	7,312,979
	$	926,464	1,876,039	1,876,039	1,876,039	25,008,482	57,782	31,620,844

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 June 30, 2018, the gross balance of the Term Loan was $23,637,600 (US$18,000,000), exclusive of the debt issuance costs. The Term Loan matures on September 15, 2022.

13. Supplemental Cash Flow Information

	Three Months Ended June 30		Six Months Ended June 30	
	2018	2017	**2018**	2017
Provided by (used in):				
Accounts receivable	**$ (695,390)**	$ 8,518	**$ (460,396)**	$ 96,242
Prepaid expenses	**(14,839)**	30,027	**29,559**	61,888
Accounts payable and accrued liabilities	**(572,505)**	147,678	**178,267**	(596,116)
Total changes in non-cash working capital	**$ (1,282,734)**	$ 186,225	**$ (252,570)**	$ (437,986)
Provided by (used in):				
Operating activities	**$ (837,100)**	$ 14,143	**$ (1,544,643)**	$ (310,346)
Investing activities	**(445,634)**	172,082	**1,292,073**	(127,640)
Total changes in non-cash working capital	**$ (1,282,734)**	$ 186,225	**$ (252,570)**	$ (437,986)

Cash interest paid on the Company's debts during the three months ended June 30, 2018 were $586,034 compared to $139,043 for the three months ended June 30, 2017. For the six months ended June 30, 2018 and 2017, cash interest paid on the Company's debts were $1,082,527 and $286,061, respectively.

Hemisphere energy corporation

OFFICERS

Don Simmons, P.Geol.
President & Chief Executive Officer

Dorlyn Evancic, CPA, CGA
Chief Financial Officer

Ian Duncan, P.Eng.
Chief Operating Officer

Andrew Arthur, P.Geol.
Vice President, Exploration

Ashley Ramsden-Wood, P.Eng.
Vice President, Engineering

BOARD OF DIRECTORS

Charles O'Sullivan, B.Sc., *Chairman*(2)(3)

Frank Borowicz, QC, CA (Hon)(1)(2)(3)

Bruce McIntyre, P.Geol.(1)(2)(4)

Don Simmons, P.Geol.(3)(4)

Gregg Vernon, P.Eng.(1)(4)

Richard Wyman, B.Sc., MBA(1)(4)

(1) Audit Committee
(2) Compensation/Nominating Committee
(3) Corporate Governance Committee
(4) Reserves Committee

BANKER

Alberta Treasury Branches
Calgary, Alberta

AUDITOR

KPMG LLP
Vancouver, British Columbia

TRANSFER AGENT

Computershare Investor Services Inc.
Vancouver, British Columbia

LEGAL COUNSEL

Burnet, Duckworth & Palmer LLP
Calgary, Alberta
Harper Grey LLP
Vancouver, British Columbia

INDEPENDENT ENGINEER

McDaniel Associates & Consultants Ltd.
Calgary, Alberta

INVESTOR RELATIONS

Scott Koyich, Brisco Capital
Calgary, Alberta

Hemisphere Energy Corporation
Suite 501, 905 West Pender Street, Vancouver, British Columbia V6C 1C6
Telephone: (604) 685-9255 | Facsimile: (604) 685-9676
www.hemisphereenergy.ca | TSX-V: HME