www.hemisphereenergy.ca

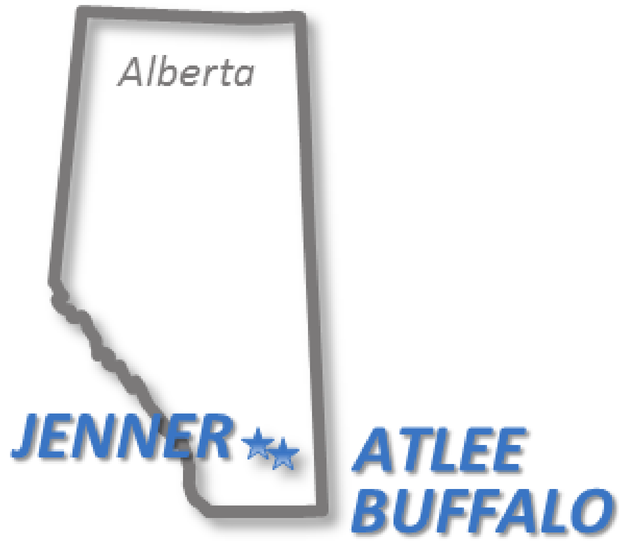
TSX-V: HME

Hemisphere energy corporation

2017 ANNUAL REPORT

Corporate Summary

Hemisphere Energy Corporation is a producing oil and gas company focused on developing conventional oil assets with low risk drilling opportunities. Hemisphere plans continual growth in production, reserves, and cash flow by focusing on existing assets with significant growth potential and executing strategic acquisitions. Hemisphere trades on the TSX Venture Exchange as a Tier 1 issuer under the symbol "HME".



2018 Annual General and Special Meeting of Shareholders

June 22, 2018 at 9:30 am Pacific Daylight Time
Oceanic Plaza, Pender Room
1035 West Pender Street, Vancouver, British Columbia

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2017 FINANCIAL AND OPERATING HIGHLIGHTS

		Year Ended December 31		
		2017		2016
FINANCIAL				
Petroleum and natural gas revenue	**$**	**10,974,634**	$	6,221,497
Operating netback[(1)]		**4,913,240**		2,347,748
Funds flow from operations[(2)]		**2,476,049**		530,567
Per share, basic and diluted		**0.03**		0.01
Net loss		**(3,796,175)**		(2,680,647)
Per share, basic and diluted		**(0.04)**		(0.03)
Capital expenditures		**8,689,240**		2,722,376
Net debt[(3)]		**18,558,361**		11,827,170
Bank indebtedness		**-**		11,247,537
Term loan	**$**	**18,868,500**	$	-
OPERATING				
Average daily production				
Oil (bbl/d)		**612**		450
Natural gas (Mcf/d)		**270**		452
NGL (bbl/d)		**2**		2
Combined (boe/d)		**659**		527
Oil and NGL weighting		**93%**		86%
Average sales prices				
Oil ($/bbl)	**$**	**47.94**	$	35.67
Natural gas ($/Mcf)		**2.33**		1.96
NGL ($/bbl)		**47.69**		29.08
Combined ($/boe)	**$**	**45.62**	$	32.23
Operating netback ($/boe)				
Petroleum and natural gas revenue	**$**	**45.62**	$	32.23
Royalties		**7.56**		3.57
Operating costs		**14.66**		12.46
Transportation costs		**2.90**		4.04
Operating field netback[(4)]		**20.50**		12.16
Realized commodity hedging loss		**0.08**		-
Operating netback[(1)]	**$**	**20.42**	$	12.16

Notes:

(1) 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.

(2) 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.

(3) 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.

(4) 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.

	As at December 31	
	2017	2016
RESERVES		
Proved (Mboe)[(1)]	**4,922.7**	3,141.1
Proved plus Probable (Mboe)[(1)]	**7,174.8**	4,564.2
COMMON SHARES		
Common shares outstanding	**89,793,302**	85,745,102
Stock options outstanding	**8,169,000**	4,385,000
Warrants outstanding	**13,750,000**	-
Fully diluted shares outstanding	**111,712,302**	90,130,102
Weighted-average shares outstanding – basic and diluted	**88,495,660**	80,672,032

Note:

(1) Reserves as attributed by the Company's independent reserves evaluator, McDaniel & Associates Consultants Ltd., in its report dated March 9, 2018 and effective as of December 31, 2017, prepared in accordance with the COGE Handbook and National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities.

MESSAGE TO SHAREHOLDERS

Dear Fellow Hemisphere Shareholders,

Well that was a better year!! 2017 was a busy and very successful time for Hemisphere Energy and we have carried that exciting momentum into 2018.

The oil and gas price environment and our production levels improved steadily throughout the year and resulted in Hemisphere having its second-best year ever in revenue at just under $11 million, which was 76% higher than in 2016.

Late in the third quarter of last year, Hemisphere entered a new and significantly increased credit facility with Cibolo Energy Partners, a Houston based firm focused on investing in oil and gas opportunities. This transformational deal has allowed us to accelerate the development of our substantial oil assets in Southern Alberta. Due to the continued success of our Atlee Buffalo waterflood projects and execution of a six well Fall 2017 development program, Hemisphere increased:

- ✓ Annual average production rate by 25% to 659 barrels of oil equivalent per day (93% oil)
- ✓ Proved plus Probable (2P) net present value before tax, discounted at 10%, (NPV10 BT) by 77% to $116.7 million
- ✓ Net asset value by 68% to $1.12 per basic share.

Notably in 2017, McDaniel & Associates, our independent reserve evaluator, converted 125% of 2016 year-end Probable reserves into Proved (1P) reserves, and then recognized an increase to our 2P reserve volumes by 57% over 2016. Despite a lower overall price forecast in the reserve report, Hemisphere's NPV10 BT has increased by over 75% in both the 1P and 2P categories in 2017 when compared to 2016. To date, Atlee Buffalo has been allocated just 12% of its estimated 66 million barrels of oil in place as 2P reserves, when offset analogue pools have produced up to 40% of their oil in place with similar enhanced oil recovery schemes. Hemisphere believes that a significant amount of waterflood expansion activity this year will help to ensure that the full value of this asset is reflected on the books in the coming years.

I'm very pleased with the tremendous growth we have accomplished over the past year. Hemisphere most definitely has the oil assets for growth, the team to deliver results, and now the access to capital required to deliver terrific economics in an improving oil price environment.

I'd like to switch gears for a moment, from Hemisphere Energy's achievements to the broader Canadian energy sector. For many years now Canadian oil companies have faced challenges with a significant downturn in commodity pricing. Global oil prices may be out of our hands, yet successful Canadian energy companies focus on what they can control: operating costs, capital allocation and expenditures, and overhead. As corporations we rely on our governments to provide us the opportunity and framework to operate in a safe, environmentally sound, and economically competitive manner compared to corporate peers in other jurisdictions. When this breaks down, we lose both domestic and foreign investors and our country suffers economically for it.

Canada has substantial oil and gas reserves with the skilled workforce to extract them economically even amongst the highest environmental regulations in the world. The royalties and taxes generated from Canada's energy industry help give us some of the best standards of living on the globe. They assist us in having national healthcare and education systems, and they provide secure, long term, and rewarding jobs. In this country we all profit from sound and environmentally responsible resource development, and as a country we should be looking to boost the value of all Canadian commodities that are sold to maximize these benefits for both current and future Canadian generations.

Currently the most pressing issue in the Canadian oil and gas sector is pipeline capacity to access global markets from the coasts. A number of pipeline projects have been approved; however, none have moved forward due to environmental activism, political posturing, and repeated challenges in the legal system. Canada is becoming known as one of the hardest places to do business in the world because even when projects are fully vetted and approved after going through years of rigorous regulatory review, the goalposts change.

Pipeline access to the world market will help us to avoid 'giving away' our Canadian resources, royalties, and taxes to a single US market. Canada sells oil at a discount, while importing the same product at a premium in other parts of the country. These imports come from countries without equivalent strict environmental rules and regulatory bodies, and often from nations without the same human rights policies that Canada prides itself in having. I believe in the end the "rule of law" will prevail and that our political leadership will act in the interest of the entire nation, and not just for the lobbyists who oppose development while offering no meaningful alternative to the increasing global demand for energy.

I encourage everyone to discuss these Canadian issues with your friends and family. If you choose to support your Canadian energy industry, please remember that every voice counts and matters in this great country and that you can make a difference by getting involved in the debate.

I'd personally like to thank every shareholder for your support of Hemisphere over the years. Your involvement provides additional drive for the Hemisphere Team to succeed. We are one of the only junior oil and gas companies in our space to survive the downturn, and we are now bigger and stronger than ever before, with a clear path forward to significant growth and value creation.

Thank you for your continued confidence and support.

Best regards,

(Signed) *"Don Simmons"*
Don Simmons, P.Geol.
President & Chief Executive Officer
April 26, 2018

Please refer to the attached Management's Discussion and Analysis for Reader Advisories regarding, among other matters, forward-looking information, non-IFRS measures, analogous information, reserves advisories and original oil in place. This Message to Shareholders should be read in conjunction with the audited annual financial statements of Hemisphere Energy Corporation together with Management's Discussion and Analysis for the year ended December 31, 2017, which can be found on SEDAR at www.sedar.com and is subject to the same cautionary statements as set out therein.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Dated as at April 26, 2018

The following Management's Discussion and Analysis ("MD&A") is a review of the operations and current financial position for the year ended December 31, 2017 for Hemisphere Energy Corporation ("Hemisphere" or the "Company") and should be read in conjunction with the audited annual financial statements and related notes as at and for the years ended December 31, 2017 and 2016. 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 audited annual financial statements which were prepared in accordance with International Financial Reporting Standards ("IFRS"), as issued by the International Accounting Standards Board ("IASB").

This MD&A contains non-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 23,810 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 14,560 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 $2,476,049 ($0.03/share) for the year ended December 31, 2017, as compared to $530,567 ($0.01/share) for the year ended December 31, 2016. For the fourth quarter of 2017, the Company generated funds flow from operations of $714,801 ($0.01/share) as compared to $273,180 ($0.00/share) for the fourth quarter of 2016.

The increases in funds flow from operations for both the year ended and three months ended December 31, 2017 are the result of increased production and an increase in commodity prices.

The Company reported a net loss of $3,796,175 ($0.04/share) for the year ended December 31, 2017 as compared to a net loss of $2,680,647 ($0.03/share) for the year ended December 31, 2016. For the fourth quarter of 2017, the Company reported a net loss of $3,310,977 ($0.04/share) compared to a net loss of $620,028 ($0.01/share) for the fourth quarter of 2016. The total net loss for 2017 includes an unrealized loss on financial instruments of $2,423,282 as disclosed in the notes of the audited annual financial statements.

Production

	Three Months Ended December 31		Year Ended December 31	
By product	**2017**	2016	**2017**	2016
Oil (bbl/d)	**725**	534	**612**	450
Natural gas (Mcf/d)	**259**	330	**270**	452
NGL (bbl/d)	**2**	1	**2**	2
Total (boe/d)	**770**	590	**659**	527
Oil and NGL weighting	**94%**	91%	**93%**	86%

In the fourth quarter of 2017, the Company's average daily production was 770 boe/d (94% oil and NGL). This represents a 31% increase in production from the fourth quarter of 2016. The Company's average daily production for the year ended December 31, 2017 increased by 25% to 659 boe/d (93% oil and NGL) from the year ended December 31, 2016. These increases are the result of bringing on new wells from the fall drilling program in the fourth quarter and the continued success of the waterflood in Atlee Buffalo.

Average Benchmark and Realized Prices

	Three Months Ended December 31		Year Ended December 31	
	2017	2016	**2017**	2016
Benchmark Prices				
WTI (US$/bbl)(1)	**$ 55.40**	$ 49.29	**$ 50.94**	$ 43.32
Exchange rate (Cdn$/US$)	**1.2705**	1.3347	**1.2966**	1.3241
WTI (C$/bbl)	**70.38**	65.79	**66.05**	57.36
WCS (C$/bbl)(2)	**48.44**	44.31	**48.93**	38.30
AECO natural gas ($/Mcf)(3)	**1.72**	3.11	**2.20**	2.18
Average realized prices				
Crude oil ($/bbl)	**52.02**	42.91	**47.94**	35.67
Natural gas ($/Mcf)	**2.05**	3.05	**2.33**	1.96
NGL ($/bbl)	**53.01**	46.32	**47.69**	29.08
Combined ($/boe)	**$ 49.80**	$ 40.63	**$ 45.62**	$ 32.23

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 may vary over periods as a result of changes in commodity prices and/or production volumes. 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 the WTI price and 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 23% from $40.63/boe during the fourth quarter of 2016 to $49.80/boe during the fourth quarter of 2017. For the year ended December 31, 2017, the Company's combined average realized price increased by 42% to $45.62/boe from $32.23 in 2016. These increases are mainly the result of an 18% year-over-year increase in WTI benchmark pricing due to sustained production cuts by the Organization of the Petroleum Exporting Countries (OPEC) as well as non-OPEC countries, strong North American refinery utilization rates, declining US crude inventories, and growth in demand.

As at the date of this MD&A, 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 1, 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 holds a one-time option no later than June 30, 2018 to extend a swap on 150 bbl/d of crude oil at US$54.65 for the term indicated.

At December 31, 2017, the commodity contracts were fair valued as a liability of $2,423,282 recorded on the balance sheet, and unrealized losses of $2,644,411 and $2,423,282 were recorded for the three months and year ended December 31, 2017, respectively.

Revenue

	Three Months Ended December 31		Year Ended December 31	
	2017	2016	**2017**	2016
Oil	**$ 3,469,957**	$ 2,109,440	**$ 10,715,271**	$ 5,876,827
Natural gas	**48,734**	92,643	**229,682**	324,741
NGL	**9,873**	4,752	**29,679**	19,929
Total	**$ 3,528,565**	$ 2,206,835	**$ 10,974,634**	$ 6,221,497

Revenue for the three months and year ended December 31, 2017 increased by 60% and 76%, respectively, from the comparable periods in 2016. These increases are due to increased production and an increase in commodity prices over the comparative periods.

Operating Netback

	Three Months Ended December 31		Year Ended December 31	
	2017	2016	**2017**	2016
Operating netback				
Revenue	**$ 3,528,565**	$ 2,206,835	**$ 10,974,634**	$ 6,221,497
Royalties	**539,402**	252,298	**1,817,607**	689,479
Operating costs	**928,222**	951,947	**3,527,059**	2,404,660
Transportation costs	**213,756**	141,741	**698,074**	779,611
Operating field netback(1)	**1,847,185**	860,849	**4,931,894**	2,347,747
Realized commodity hedging gain (loss)	**(196,739)**	-	**(18,654)**	-
Operating netback(2)	**$ 1,650,446**	$ 860,849	**$ 4,913,240**	$ 2,347,747
Operating netback ($/boe)				
Revenue	**$ 49.80**	$ 40.63	**$ 45.62**	$ 32.23
Royalties	**7.61**	4.64	**7.56**	3.57
Operating costs	**13.10**	17.52	**14.66**	12.46
Transportation costs	**3.02**	2.61	**2.90**	4.04
Operating field netback(1)	**26.07**	15.85	**20.50**	12.16
Realized commodity hedging loss	**2.78**	-	**0.08**	-
Operating netback(2)	**$ 23.29**	$ 15.85	**$ 20.42**	$ 12.16

Notes:

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

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

Royalties for the fourth quarter of 2017 were $7.61/boe, representing a 64% increase from the fourth quarter of 2016. For the year ended December 31, 2017, royalties increased by 112% from the comparable period in 2016. These increases are a result of the increase in commodity prices in the fourth quarter, which directly impactedUS$ the calculation of payable royalty per well, in addition to the older Atlee Buffalo wells now being off royalty holiday, as well as a gross overriding royalty adjustment allocated through December 31, 2017. Atlee wells have seen an overall increase in production rates due to waterflood, which also makes them subject to an increased percentage of payable royalty.

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 decreased for the three months ended December 31, 2017 by $4.42/boe from the comparable period in 2016, which is a result of several workovers and extreme cold weather in the last quarter of 2016 resulting in higher than average costs. For the year ended December 31, 2017, operating costs increased to $14.66/boe, or 18% when compared to 2016, as a result of the loss of third party processing fees in Jenner, new facilities and wells being managed, a significant turnaround in Jenner, and increased trucking to move water around within the field prior to the new G pool injection facility being added in November.

Transportation costs include all costs incurred to transport emulsion, oil and gas sales to processing and distribution facilities. For the fourth quarter of 2017, transportation costs increased by 16% from the comparable period in 2016. This overall increase in transportation cost is due to more trucking in Atlee prior to setup of the new facility in November 2017. For the year ended December 31, 2017, transportation costs decreased by 28% from the year ended December 31, 2016. This overall decrease in trucking in 2017 was due to lower trucking rates due to sustained depressed commodity pricing, and the reduction of trucking water between facilities in Atlee when facilities were added in late 2016.

Operating field netback for the three months and year ended December 31, 2017 were $26.07/boe and $20.50/boe, respectively. This represents a 69% annual increase for 2017 in operating field netback, mainly as a result of the 42% increase in combined commodities pricing.

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 expense increased for the three months and year ended December 31, 2017 by $543,001 and $576,586, respectively, from the comparable periods of 2016. Exploration and evaluation expense for the three months and year ended December 31, 2017 were the result of a damaged well and several land expiries which occurred in 2017.

Depletion and Depreciation

	Three Months Ended December 31		Year Ended December 31	
	2017	2016	**2017**	2016
Depletion expense	**$ 842,602**	$ 709,750	**$ 3,090,462**	$ 2,787,391
Depreciation expense	**1,845**	2,489	**7,377**	9,954
Total	**$ 844,447**	$ 712,239	**$ 3,097,839**	$ 2,797,345
$ per boe	**$ 11.92**	$ 13.11	**$ 12.88**	$ 14.49

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 expense for the fourth quarter of 2017 increased by 19% from the fourth quarter of 2016. For the year ended December 31, 2017, depletion and depreciation expense decreased by 11% from the year ended December 31, 2016.

For the twelve months ended December 31, 2017, depletion and depreciation expenses decreased to $12.88/boe from $14.49/boe for the same period in 2016. This decrease is due to depletion of production over a larger reserve volume base from the Company's December 31, 2017 independent engineers evaluation report as prepared by McDaniel & Associates Consultants Ltd.

Capital Expenditures

	Three Months Ended December 31		Year Ended December 31	
	2017	2016	**2017**	2016
Land and lease	**$ 49,849**	$ 8,624	**$ 74,649**	$ 30,296
Geological and geophysical	**60,028**	80,829	**225,906**	254,155
Drilling and completions	**2,604,811**	274,217	**5,058,543**	1,301,633
Investment in facilities	**1,948,754**	352,093	**3,330,142**	1,136,292
Total capital expenditures(1)	**$ 4,663,442**	$ 715,763	**$ 8,689,240**	$ 2,722,376

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

The development capital spent during 2017 included capital associated with the completion of a six well drilling program, expansion of the Upper Mannville F pool battery, construction of the Upper Mannville G pool battery, installation of larger downhole pumps in producing wells and various wellsite electrification work.

General and Administrative Expense ("G&A")

	Three Months Ended December 31		Year Ended December 31	
	2017	2016	**2017**	2016
Gross G&A	**$ 690,019**	$ 539,120	**$ 1,971,364**	$ 1,570,078
Capitalized G&A	**(137,476)**	(94,333)	**(386,528)**	(291,114)
Total	**$ 552,543**	$ 444,787	**$ 1,584,837**	$ 1,278,964
$ per boe	**$ 7.80**	$ 8.19	**$ 6.59**	$ 6.63

Gross G&A costs for the three and twelve months ended December 31, 2017 increased by 28% and 26% respectively over the comparable periods of 2016 due to increased activity resulting in higher consulting fees and salaries.

The Company capitalizes certain G&A which can be attributed to costs incurred during the period relating to its development and exploration activities. For the year ended December 31, 2017, capitalized G&A increased by 33% from the comparable period in 2016 and is due to the Company completing its six well drilling program in the fall of 2017.

For the three and twelve months ended December 31, 2017, the Company realized a decrease of $0.39/boe and $0.04/boe respectively in general and administrative costs over the same periods in 2016. This is a result of increased production which offset the increase gross general and administrative expenses for the quarter.

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 years ended December 31, 2017 and 2016, the Company recorded share-based payments of $233,508 and $89,711, respectively.

In September of 2017, the Company granted 5,034,000 stock options to directors, officers, employees and consultants at an exercise price of $0.25 each, of which 1,678,000 vested immediately. In October of 2017, the Company granted 150,000 stock options to an employee at an exercise price of $0.28 each, of which 50,000 vested immediately. 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. The total valuation of the vested options from the grants was $332,669, of which $233,508 was expensed as stock-based compensation and $99,161 was capitalized.

	Three Months Ended December 31		Year Ended December 31	
	2017	2016	**2017**	2016
Share-based payments	**$ 18,028**	$ 1,135	**$ 233,508**	$ 89,711
Capitalized costs	**-**	-	**99,161**	26,893
Total share-based payments	**$ 18,028**	$ 1,135	**$ 332,669**	$ 116,604

Finance Expense

	Three Months Ended December 30		Year Ended December 30	
	2017	2016	**2017**	2016
Cash interest expense	**$ 382,649**	$ 142,882	**$ 834,078**	$ 538,216
Amortization of deferred charges	**74,037**	-	**87,837**	-
Accretion of debt issuance costs	**46,453**	-	**48,738**	-
Accretion of decommissioning liabilities	**26,932**	35,792	**107,727**	143,166
Total	**$ 530,070**	$ 178,674	**$ 1,078,380**	$ 681,382
$ per boe	**$ 8.46**	$ 3.75	**$ 4.48**	$ 3.53

Finance expense for the three months and year ended December 31, 2017 increased by 197% and 58%, respectively, over the comparable periods in 2016. These increases are the 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 2016.

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. For the three months and year ended December 31, 2017, accretion expense was $26,932 and $107,727, respectively. The decreases in accretion expense in 2017 from the comparable periods of 2016 are a result of lower estimated risk free and inflation rates used for valuation of the accretion in 2017 over the comparable year of 2016.

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

Selected Annual Information

The following are highlights of the Company's financial data for the three most recently completed fiscal years:

	Year Ended December 31		
	2017	2016	2015
Average daily production (boe/d)	**659**	527	776
Petroleum and natural gas revenue	**$ 10,974,634**	$ 6,221,497	$ 9,749,377
Operating netback(1)	**4,913,240**	2,347,747	5,335,096
Funds flow from operations(2)	**2,476,049**	530,567	3,188,486
Per share, basic and diluted	**0.03**	0.01	0.04
Net loss	**(3,796,175)**	(2,680,648)	(8,310,831)
Per share, basic and diluted	**(0.04)**	(0.03)	(0.11)
Average realized price ($/boe)	**45.62**	32.23	34.41
Operating netback ($/boe)(1)	**20.42**	12.16	18.83
Capital expenditures, including property acquisitions	**8,689,241**	2,722,375	3,086,147
Net debt(3)	**18,558,361**	11,827,170	11,446,110
Bank indebtedness	**-**	11,247,537	10,828,040
Term loan(4)	**18,868,500**	-	-
Total assets	**$ 49,069,803**	$ 39,696,007	$ 40,811,044

Notes:

(1) 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.

(2) 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.

(3) 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.

(4) Gross loan amount.

Summary of Quarterly Results

	2017				2016			
	Dec. 31 Q4(1)	Sep. 30 Q3(2)	Jun. 30 Q2(2)	Mar. 31 Q1(3)	Dec. 31 Q4(4)	Sep. 30 Q3(5)	Jun. 30 Q2(6)	Mar. 31 Q1(7)
Average daily production (boe/d)	770	681	600	583	590	518	492	508
Petroleum and natural gas revenue	3,528,565	2,733,656	2,419,666	2,292,746	2,206,835	1,630,105	1,448,722	935,834
Operating netback(8)	1,650,446	1,208,106	1,096,412	958,276	860,849	779,966	580,876	126,056
Funds flow from operating activities	714,801	657,840	598,078	505,331	273,181	345,007	159,894	(247,514)
Per share, basic and diluted	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00
Net loss	(3,308,520)	(142,254)	(206,724)	(138,678)	(620,027)	(413,340)	(580,725)	(1,066,556)
Per share, basic and diluted	(0.04)	(0.00)	(0.00)	(0.00)	(0.01)	0.00	(0.01)	(0.01)
Combined average realized price ($/boe)	49.80	43.62	44.34	43.68	40.63	34.19	32.34	20.24
Operating netback ($/boe)	23.29	19.28	20.09	18.26	15.85	16.36	12.97	2.73

Notes:

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

(2) 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.

(3) 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.

(4) 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.

(5) 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.

(6) 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.

(7) The decreases in net income, funds flow from operations and petroleum and natural gas netbacks for this quarter can be attributed to the decrease in the Company's combined average realized price resulting from the decline in commodity prices, and lower production volumes.

(8) 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 Data

	April 26, 2018	**December 31, 2017**	December 31, 2016
Fully diluted share capital			
Common shares issued and outstanding	89,793,302	**89,793,302**	85,745,102
Stock options	8,419,000	**8,169,000**	4,385,000
Warrants	13,750,000	**13,750,000**	-
Total fully diluted shares outstanding	111,962,302	**111,712,302**	90,130,102

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/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 to the Company of $1,133,496.

The Company has the following stock options that are outstanding and exercisable as at April 26, 2018:

Exercise Price	Grant Date	Expiry Date	Balance Outstanding April 26, 2018	Balance Exercisable April 26, 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

Subsequent to year-end, on January 1, 2018, the Company granted a consultant 250,000 stock options at an exercise price of $0.25 per share of which one-third vested immediately, one-third vests on the first anniversary, and one-third vests on the second anniversary of the grant date.

On September 15, 2017, the Company issued 13,750,000 warrants to a third-party lender in conjunction with its Term Loan. 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/share. The warrants are non-transferable.

Liquidity and Capital Management

The Company's net debt as at December 31, 2017 and 2016 were $18,558,361 and $11,827,170, respectively, representing an increase in net debt of $6,731,191.

a) Financing

The Company's net cash provided by financing activities during the year ended December 31, 2017 was $7,102,963. This includes the proceeds of $17,302,753, net of debt issuance costs, which the Company received from the initial draws on the new term loan in the fall of 2017 (as further disclosed in Note 12 of the Company's audited annual financial statements for the year ended December 31, 2017). The initial draws were primarily used to payout the $11,247,537 balance of the Company's bank credit facility in full and fund the Company's fall drill program.

On April 27, 2017, 4,048,200 flow-through shares were issued at a price of $0.28/share through a non-brokered private placement offering for a net proceeds of $1,047,747.

b) Credit Facility

Effective September 15, 2017, the Company repaid and terminated its $12.5 million credit facility with Alberta Treasury Branches.

c) 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 of which US$15.0 million had been drawn as at December 31, 2017 (CAD$18,868,500). The Company's ability to access additional commitments in excess of US$15.0 million is subject to approval of the Lender based on review and approval of the Company's future development plans.

On January 23, 2018, the Company amended its credit agreement with its Lender with an increase to the commitment by US$5.0 million, bringing the aggregate amount committed by the Lender under the Term Loan to US$20.0 million. The Company drew US$3.0 million of this commitment in February 2018.

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

<u>minus</u>

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

i) Other non-Cash items increasing consolidated net income for such period (excluding any such non-Cash item to the extent it represents the reversal of an accrual or reserve for potential Cash item in any prior period), <u>plus</u>
ii) Interest income, <u>plus</u>
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 $2.0 million per annum as at December 31, 2017, and escalating to $2.5 million per annum in 2018 for each year thereafter. The Company recorded $1,971,364 in gross cash G&A costs and was in compliance with its G&A covenant.

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.

d) 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.

Related Party Transactions

Compensation to key executive personnel, consisting of the Company's officers, directors and Chairman, was paid as follows:

	Three Months Ended December 31		Years Ended December 31	
	2017	2016	**2017**	2016
Salaries and wages	**$ 205,000**	$ 210,000	**$ 768,333**	$ 650,167
Share-based payments	**-**	-	**172,575**	76,334

The Company granted 3,690,000 incentive stock options to related parties in September 2017. One third of these options (1,230,000) vested immediately, with a Black and Scholes valuation of $172,575.

Commitments

The Company has a commitment to make monthly rental payments pursuant to the office rental agreement at its current location until May 30, 2018. The Company has a commitment to make monthly rental payments pursuant to the office rental agreement at its new location commencing June 1, 2018 until May 30, 2023.

On April 27, 2017, the Company issued 4,048,200 Canadian Development Expense flow-through shares at $0.28 per share for gross proceeds of $1,133,496 which had a commitment to be expended pursuant to the provisions of the *Income Tax Act* (Canada) by December 31, 2017. As at December 31, 2017, the Company has expended its commitment and recorded a deferred tax recovery of $161,928.

As at December 31, 2017, the gross balance of the Term Loan was $18,868,500 (US$15,000,000), exclusive of the debt issuance costs. The Term Loan matures on September 15, 2022.

		2018	2019	2020	2021	2022	Total
Office Rental	$	149,946	138,676	138,676	138,676	138,676	704,649
Term Loan		-	-	-	-	18,868,500	18,868,500
Term Loan Interest		1,664,202	1,664,202	1,664,202	1,664,202	1,180,317	7,837,124
	$	1,814,148	1,802,877	1,802,877	1,802,877	20,187,493	27,410,273

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.

Critical Accounting Estimates

The Company's significant accounting estimates, judgments and policies are set out in Notes 2 and 3 of the audited annual financial statements for the year ended December 31, 2017 and have been consistently followed in the preparation of the audited annual financial statements.

The preparation of these audited annual 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 differ from these estimates. A discussion of specific estimates and judgments employed in the preparation of the Company's unaudited interim condensed financial statements is included in the Company's audited annual financial statements for the year ended December 31, 2017.

An additional significant area of estimation, uncertainty and critical judgment in applying accounting policies that has a significant effect on the amount recognized in the financial statements is foreign exchange. Estimates of foreign exchange conversion to value US dollar dominated amounts into Canadian currency include the Term Loan, cash balances and hedging contracts.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected.

Newly Adopted Accounting Standards

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. The Company is currently evaluating the impact that these standards will have on results of operations and financial position.

a) 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, with earlier adoption permitted. The Company has conducted the process of identifying and reviewing sales contracts with customers to determine the extent of the impact, and has determined that this standard will have no impact on net loss.

b) 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. The Company has determined that IFRS 9 will not result in any material changes to its classification of financial assets or liabilities, nor will it have a material impact to the measurement and carrying value of the Company's financial instruments. The standard will come into effect for annual periods beginning on or after January 1, 2018.

c) In January 2016, 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 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.

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

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:

		December 31, 2017		December 31, 2016
Accounts receivable				
Marketing receivables	**$**	**1,284,474**	$	774,366
Trade receivables	**$**	**76,437**	$	88,749
Receivables from joint ventures		**7,297**		45,088
Reclamation deposits		**115,535**		115,535
	$	**1,483,743**	$	1,023,738

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 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 December 31, 2017, the Company had net debt (current assets less current liabilities excluding fair value of financial instruments, and outstanding Term Loan) of $18,558,361 (December 31, 2016 - $11,827,170), which includes Term Loan of $18,868,500 (December 31, 2016 - $11,247,537). Effective September 15, 2017, the Company repaid and terminated its $12.5 million credit facility with Alberta Treasury Branches. 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 $150,000 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 $30,000 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", "operating field 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 December 31		Year Ended December 31	
	2017	2016	**2017**	2016
Cash provided by operating Activities	**$ 166,399**	$ 601,242	**$ 1,915,248**	$ 432,604
Change in non-cash working capital	**(548,402)**	328,061	**(560,801)**	97,963
Funds flow from operations	**$ 714,801**	$ 273,181	**$ 2,476,049**	$ 530,567
Per share, basic and diluted	**$ 0.01**	$ 0.00	**$ 0.03**	$ 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 barrel of oil equivalent 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 basis.

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 December 31	
	2017	2016
Current assets[1]	**$ 2,955,446**	$ 1,078,020
Current liabilities[2]	**(2,645,307)**	(1,657,652)
Bank indebtedness	**-**	(11,247,537)
Term Loan[3]	**(18,868,500)**	-
Net debt	**$ (18,558,361)**	$ (11,827,170)

Notes:
(1) Excluding fair value of financial instruments.
(2) Excluding bank indebtedness.
(3) Gross loan amount.

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.

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 (particularly the Message to Shareholders) 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 (particularly the Message to Shareholders) contains forward-looking statements pertaining to the following: volumes and estimated net present value of the future net revenue of Hemisphere's oil and natural gas reserves; future oil and natural gas prices; future operational activities; and plans for continued growth in the Company's production, reserves and cash flow; and the expectation for the increasing of the Company's reserves with continued successful waterflood operations. 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.*

Analogous Information

The information concerning analogue pools in this MD&A (particularly in the Message to Shareholders, included with the Annual Report) may be considered to be "analogous information" within the meaning of applicable securities laws. Such information was obtained by Hemisphere management throughout the year ended December 31, 2017 from various public sources including information available to Hemisphere through the Alberta Energy Regulator. Management believes that the performance of such pools is analogous to the pools in which the Company has an interest at its Atlee Buffalo property area and is relevant as it may help to demonstrate the reaction of such pools to waterflood stimulations. Hemisphere is unable to confirm whether the analogous information was prepared by a qualified reserves evaluator or auditor or in accordance with National Instruments 51-101 – Standards of Disclosure for Oil and Gas Activities and the COGE Handbook and therefore, the reader is cautioned that the data relied upon by Hemisphere may be in error and/or may not be analogous to the oil pools in which Hemisphere holds an interest.

Reserves Advisories

It should not be assumed that the net present value of the estimated net revenues of the reserve presented in herein represent the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions upon which such estimates are made will be attained and variances could be material. The reserve estimates of Hemisphere's crude oil, natural gas liquids and natural gas reserves and any estimated recovery factors provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquids reserves may be greater than or less than the estimates provided herein.

Original Oil in Place

The reference to Original Oil-In-Place ("OOIP") in the Message to Shareholders is equivalent to Discovered Petroleum Initially-In-Place ("DPIIP"). DPIIP, as defined in the Canadian Oil and Gas Handbook, is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production. The recoverable portion of DPIIP includes production, reserves and contingent resources; the remaining portion of DPIIP is unrecoverable. It should not be assumed that any portion of the OOIP/DPIIP set forth in the presentation is recoverable other than the portion which has been attributed reserves by McDaniel & Associates Consultants Ltd. There is uncertainty that it will be commercially viable to produce any portion of the OOIP/DPIIP other than the portion that is attributed reserves. The OOIP/DPIIP set forth in the Message to Shareholders has been provided for the sole purpose of highlighting the potential recovery factors for the reservoirs in which the Company holds an interest. The OOIP/DPIIP volumes set forth in the Message to Shareholders are from the mapping of the reservoirs by McDaniel & Associates Consultants Ltd. (who is independent of Hemisphere) in connection with preparing the Company's reserve report effective as of December 31, 2017.

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. Independent auditors appointed by the shareholders have examined the financial statements. Their report is presented with the financial statements. The Audit Committee, consisting of independent members of the Board of Directors, has reviewed the financial statements with management and the independent auditors. The Board of Directors has approved the financial statements on the recommendation of the Audit Committee.

Vancouver, British Columbia
April 26, 2018

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

INDEPENDENT AUDITORS' REPORT

To the Shareholders of Hemisphere Energy Corporation

We have audited the accompanying financial statements of Hemisphere Energy Corporation, which comprise the statements of financial position as at December 31, 2017 and December 31, 2016, the statements of loss and comprehensive loss, changes in shareholders' equity and cash flows for the years then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

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

Auditors' Responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

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

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Hemisphere Energy Corporation as at December 31, 2017 and December 31, 2016, and its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards.

KPMG LLP

Chartered Professional Accountants

April 26, 2018
Calgary, Canada

STATEMENTS OF FINANCIAL POSITION

(Expressed in Canadian dollars)

	Note		**December 31, 2017**		December 31, 2016
Assets					
Current assets					
Cash and cash equivalents		**$**	**1,372,991**	$	-
Accounts receivable			**1,368,208**		908,203
Prepaid expenses			**214,247**		169,817
			2,955,446		1,078,020
Non-current assets					
Reclamation deposits	9		**115,535**		115,535
Exploration and evaluation assets	7		**4,894,108**		3,260,407
Property and equipment	8		**39,894,023**		35,242,044
Deferred charges	12		**1,210,691**		-
Total assets		**$**	**49,069,803**	$	39,696,006
Liabilities					
Current liabilities					
Accounts payable and accrued liabilities		**$**	**2,645,307**	$	1,657,652
Bank indebtedness	11		**-**		11,247,537
Fair value of financial instruments	5(c)		**1,579,726**		-
			4,225,033		12,905,189
Non-current liabilities					
Term loan	12		**17,465,518**		-
Fair value of financial instruments	5(c)		**843,556**		-
Decommissioning obligations	9		**6,176,112**		4,896,681
			28,710,219		17,801,870
Shareholders' Equity					
Share capital	13		**54,724,441**		53,838,621
Contributed surplus			**649,775**		1,192,106
Warrant reserve	13(c)		**1,043,136**		-
Deficit			**(36,057,768)**		(33,136,591)
Total shareholders' equity			**20,359,584**		21,894,136
Total liabilities and shareholders' equity		**$**	**49,069,803**	$	39,696,006

Commitments (Note 15)
Subsequent events (Note 18)

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

Approved by the Board of Directors

(signed) *"Bruce McIntyre"*
Bruce McIntyre, Director

(signed) *"Don Simmons"*
Don Simmons, Director

STATEMENTS OF LOSS AND COMPREHENSIVE LOSS
(Expressed in Canadian dollars)

	Note		Years Ended December 31 2017		2016
Revenue					
Oil and natural gas revenue		$	**10,974,634**	$	6,221,497
Royalties			**(1,817,607)**		(689,479)
			9,157,027		5,532,018
Realized loss on financial instruments			**(18,654)**		-
Unrealized loss on financial instruments	5(c)		**(2,423,282)**		-
Net revenue			**6,715,091**		5,532,018
Expenses					
Production and operating			**4,225,131**		3,184,270
Exploration and evaluation	7		**576,586**		246,393
Depletion and depreciation	8		**3,097,839**		2,797,345
General and administrative			**1,584,837**		1,278,964
Share-based payments	13(b)		**233,508**		89,711
			9,717,901		7,596,683
Results from operating activities			**(3,002,810)**		(2,064,665)
Finance expense	10		**(1,078,380)**		(681,382)
Foreign exchange gain (loss)			**(262,731)**		-
Net loss before tax			**(4,343,921)**		(2,746,047)
Deferred tax recovery	17		**547,746**		65,400
Net loss and comprehensive loss for the year		**$**	**(3,796,175)**	$	(2,680,647)
Net loss per share, basic and diluted	13(d)	**$**	**(0.04)**	$	(0.03)

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

STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

(Expressed in Canadian dollars)

	Note	Number of common shares	Share Capital	Contributed Surplus	Warrant Reserve	Deficit	Total Equity
Balance, December 31, 2015		**75,803,498**	**$ 52,083,070**	**$ 2,461,870**	**$ -**	**$ (31,832,108)**	**$ 22,712,832**
Non-flow-through share issuance		6,496,604	1,234,355	-	-	-	1,234,355
Flow-through share issuance		3,270,000	686,700	-	-	-	686,700
Share issuance costs		-	(124,306)	-	-	-	(124,306)
Flow-through share premium		-	(65,400)	-	-	-	(65,400)
Exercise of stock options		175,000	24,203	(10,203)	-	-	14,000
Share-based payments		-	-	116,604	-	-	116,604
Expiry of stock options		-	-	(1,376,165)	-	1,376,165	-
Net loss for the year		-	-	-	-	(2,680,647)	(2,680,647)
Balance, December 31, 2016		**85,745,102**	**$ 53,838,621**	**$ 1,192,106**	**$ -**	**$ (33,136,591)**	**$ 21,894,136**
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	13(b)	-	-	332,669	-	-	332,669
Expiry of stock options		-	-	(875,000)	-	875,000	-
Warrant Issue – net deferred tax	13(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**

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

STATEMENTS OF CASH FLOWS

(Expressed in Canadian dollars)

	Years Ended December 31 **2017**	2016
Operating activities		
Net loss for the year	$ **(3,796,175)**	$ (2,680,647)
Items not affecting cash:		
Accretion of debt issuance costs	**48,738**	-
Accretion of decommissioning costs	**107,727**	-
Amortization of deferred charges	**87,837**	-
Deferred tax (recovery)	**(547,746)**	(65,400)
Depletion and depreciation	**3,097,839**	2,797,345
Exploration and evaluation expense	**576,586**	246,393
Share-based payments	**233,508**	89,711
Unrealized loss on financial instruments	**2,423,282**	-
Unrealized loss on foreign exchange	**244,453**	-
	2,476,049	530,567
Changes in non-cash working capital	**(560,801)**	(97,963)
Cash provided by operating activities	**1,915,248**	432,604
Investing activities		
Property and equipment expenditures	**(4,580,698)**	(2,217,499)
Exploration and evaluation expenditures	**(4,108,542)**	(504,877)
Changes in non-cash working capital	**1,044,020**	59,525
Cash used in investing activities	**(7,645,220)**	(2,662,851)
Financing activities		
Shares issued for cash, net of issue costs	**1,047,748**	1,796,749
Shares issued for stock options	-	14,000
Change in bank indebtedness	**(11,247,537)**	419,497
Proceeds from term loan (net issue costs)	**17,302,753**	-
Changes in non-cash working capital	-	-
Cash provided by financing activities	**7,102,964**	2,230,246
Net change in cash	**1,372,991**	-
Cash, beginning of year	-	-
Cash, end of year	$ **1,372,991**	$ -

Supplemental cash flow information (Note 16)

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

NOTES TO THE FINANCIAL STATEMENTS

For the years ended December 31, 2017 and December 31, 2016
(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. The Company has no subsidiaries.

2. Basis of Presentation

(a) Statement of compliance

These audited annual financial statements ("Financial Statements") have been prepared in accordance with International Financial Reporting Standards ("IFRS"), as issued by the International Accounting Standards Board ("IASB").

These Financial Statements were authorized for issuance by the Board of Directors on April 26, 2018.

(b) Basis of presentation

These Financial Statements have been prepared on a historical cost basis, except for certain 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 expectation 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.

Reserve estimation including engineering data, geological and geophysical data, projected future rates of production, commodity pricing, operating costs and timing of future expenditures, are subject to significant judgment and interpretation. These estimates are a critical part of many of the estimated amounts and calculations contained in the financial statements. These estimates are verified by third party professional engineers, who work with information provided by the Company to establish reserve determinations. These determinations are updated at least on an annual basis.

Significant areas of estimation, uncertainty and critical judgments in applying accounting policies that have the most significant effect on the amount recognized in the financial statements include:

(i) Impairment testing – internal and external sources of information including petroleum and natural gas prices, expected production volumes, anticipated recoverable quantities of proved and probable reserves and rates used to discount future cash flow estimates. Judgement is required to assess these factors when determining if the carrying amount of an asset is impaired, or in the case of previously impaired asset, whether the carrying amount of the asset has been restored.

(ii) Depletion and depreciation – oil and natural gas reserves, including future prices, costs and reserve base to use on calculation of depletion.

(iii) Decommissioning obligations – estimates relating to amounts, likelihood, timing, inflation and discount rates.

(iv) Share-based payments – expected life of the options, risk-free rate of return and stock price volatility

(v) Determinations of cash generating units ("CGUs") – geographic location, commodity type, reservoir characteristics and lowest level of cash inflows.

(vi) Determining the technical feasibility and commercial viability of exploration and evaluation assets.

(vii) Business combinations - estimates of the fair value of assets acquired and liabilities assumed which includes assessing the value of petroleum and natural gas properties based upon the estimation of recoverable quantities of Proved and Probable reserves being acquired

(viii) Provisions - exercise of significant judgment and estimates of the outcome of future events.

(ix) Deferred tax asset – the amounts recorded for deferred tax assets are based on estimates as to the timing of the reversal of temporary differences, substantially enacted tax rates, and the likelihood of tax assets being realized. The availability of tax pools and other deductions are subject to audit and interpretation by tax authorities.

3. Significant Accounting Policies

(a) Revenue

Revenue from the sale of petroleum and natural gas is recorded when the significant risks and rewards of ownership of the product passes to an external party and is based on volumes delivered to customers at contractual delivery points and rates, and collectability is reasonably assured. The costs associated with delivery prior to the delivery point, including operating and maintenance costs, transportation and royalty expenses, are recognized during the same period in which the related revenue is earned and reported.

(b) Jointly owned assets

Some of the Company's petroleum and natural gas activities involve jointly owned assets and are conducted under joint operating agreements. Accordingly the financial statements reflect the Company's proportionate share of joint assets, liabilities, revenues and expenses.

(c) Property and equipment and exploration and evaluation assets

(i) Pre-exploration expenditures

Expenditures made by the Company before acquiring the legal right to explore in a specific area do not meet the definition of an asset and therefore are expensed as incurred.

(ii) Exploration and evaluation expenditures

Costs incurred once the legal right to explore has been acquired are capitalized as exploration and evaluation assets. These costs include, but are not limited to, exploration license expenditures, leasehold property acquisition costs, evaluation costs, drilling costs directly attributable to an identifiable well, and directly attributable general and administrative costs. These costs are accumulated in cost centers by property and are not subject to depletion until technical feasibility and commercial viability has been determined.

Exploration and evaluation assets are assessed for impairment at each reporting date when facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

The technical feasibility and commercial viability are considered to be determinable when Proved and Probable reserves have been identified. A review of each exploration license or field is carried out quarterly to ascertain whether Proved and Probable reserves have been discovered. Upon determination of Proved and Probable reserves, exploration and evaluation assets attributable to those reserves are tested for impairment and reclassified from exploration and evaluation assets to petroleum and natural gas properties.

(iii) Property and equipment

Items of property and equipment, which include petroleum and natural gas development and production assets, are measured at cost less accumulated depletion and depreciation and impairment losses.

Gains and losses on disposal of an item of property and equipment, including petroleum and natural gas properties, are determined by comparing the proceeds from disposal with the carrying amount of property and equipment and are recognized in profit or loss.

(iv) Capitalization of costs

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

(v) Depletion and depreciation

Depletion of petroleum and natural gas properties is determined using the unit-of-production method based on production volumes in relation to total estimated Proved and Probable reserves as determined annually by independent engineers and determined in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities. Natural gas reserves and production are converted at the energy equivalent of six thousand cubic feet to one barrel of oil.

The calculation of depletion and depreciation is based on total capitalized costs plus estimated future development costs of Proved and Probable non-producing and undeveloped reserves.

Proved and probable reserves are estimated using independent reserve engineer reports and represent the estimated quantities of crude oil, natural gas and natural gas liquids, which geological, geophysical and engineering data demonstrate with a specified degree of certainty to be recoverable in future years from known reservoirs and which are considered commercially producible. There should be a 50 percent statistical probability that the actual quantity of recoverable reserves will be more than the amount estimated as Proved and Probable and a 50 percent statistical probability that it will be less. The equivalent statistical probabilities for the proved component of Proved and Probable reserves are 90 percent and 10 percent, respectively.

Such reserves may be considered commercially viable if management has the intention of developing and producing them. Such intention is based upon:

- A reasonable assessment of the future economics of such production;
- A reasonable expectation that there is a market for all or substantially all the expected oil and natural gas production; and

- Evidence that the necessary production, transmission and transportation facilities are available or can be made available.

Reserves may only be considered Proved if supported by either actual production or conclusive formation tests. The area of reservoir considered Proved includes (a) that portion delineated by drilling and defined by as-oil and/or oil-water contacts, if any, or both, and (b) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geophysical, geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of oil and natural gas controls the lower Proved limit of the reservoir.

Reserves that can be produced economically through application of improved recovery techniques such as fluid injection are only included in the Proved classification when successful testing by a pilot project, the operation of an installed program in the reservoir or other reasonable evidence (such as, experience of the dame techniques on similar reservoirs or reservoir simulation studies) provides support for the engineering analysis on which the project or program was based.

Depreciation of other equipment is provided for on a 20-30% declining balance basis. Depreciation methods, useful lives and residual values are reviewed at each reporting date.

(vi) Impairment

Exploration and evaluation assets are grouped together with the Company's CGUs when they are assessed for impairment, both at the time of any triggering facts and circumstances as well as upon their eventual reclassification to developed and producing assets (petroleum and natural gas properties).

Exploration and evaluation assets are assessed for impairment when they are reclassified to developing and producing assets, as part of the petroleum and natural gas properties, and also if facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

For developed and producing assets, an impairment is recorded when the recoverable amount of a CGU is less than the respective carrying amount. Recoverable amount is the higher of its fair value less cost to sell and value in use. Fair value is the price that would be received from selling an asset in an orderly transaction between market participants. Fair value less costs to sell can be determined by using observable market information or by using discounted future net cash flows of Proved and Probable reserves using forecasted prices and costs. Value in use is determined by estimating the present value of the future net cash flows expected to be derived from the continued use of the asset or CGU.

Judgment is required to assess when indicators of impairment or reversals exist and whether calculation of the recoverable amount of an asset is necessary.

Management considers internal and external sources of information including petroleum and natural gas prices, expected production volumes, anticipated recoverable quantities of proved and probable reserves and rates used to discount future cash flow estimates. Judgement is required to assess these factors when determining if the carrying amount of an asset is impaired, or in the case of previously impaired asset, whether the carrying amount of the asset has been restored.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. A CGU's recoverable amount is the higher of its fair value less costs to sell and its value in use. Impairment losses are recognized in profit or loss. Impairment losses recognized in respect of CGUs are allocated first to reduce the carrying amount of goodwill, if any, allocated to the units and then to reduce carrying amounts of other assets in the unit (group of units) on a pro rata basis.

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

(d) Decommissioning obligations

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

(e) Share-based payments

The Company has a stock option plan that is described in Note 13(b). Share-based payments to employees are measured at the fair value of the instruments issued and are amortized over the vesting periods. The offset to the recorded cost is to Company's contributed surplus.

Consideration received on the exercise of stock options is recorded as share capital and the related contributed surplus is transferred to capital stock. Charges for options that are forfeited before vesting are reversed from contributed surplus. For those options that expire after vesting, the recorded value is transferred to deficit.

(f) Share Capital and warrants

The Corporation uses the fair value method for valuing stock options, restricted and performance share awards, performance warrants and warrants. Under the fair value method, compensation costs attributable to all stock options, restricted and performance share awards, performance warrants and warrants granted are measured at fair value at the date of grant and expensed over the vesting period with a corresponding increase to contributed surplus or warrants. A forfeiture rate is estimated on the date of grant and is adjusted to reflect the actual number of awards that vest. Performance share awards are also subject to a performance multiplier that is adjusted to reflect the final number of awards. The fair value of each option, performance warrant or warrant granted is estimated using the Black-Scholes option pricing model that takes into account the grant date, the exercise price and expected life of the option, performance warrant or warrant, the price of the underlying security, the expected volatility, the risk-free interest rate and dividends, if any, on the underlying security. The fair value of each restricted and performance share award is determined with reference to the trading price of the Corporation's common shares on the date of grant. Upon the exercise of the stock options, restricted and performance share awards, performance warrants and warrants, consideration received together with the amount previously recognized in contributed surplus or warrants is recorded as an increase to share capital and the contributed surplus or warrants balance is reduced.

Incremental costs directly attributable to the issue of common shares, warrants and share options are recognized as a deduction from equity, net of any tax effects.

(g) Flow-through shares and units

The Company, from time to time, may issue flow-through common shares to finance a portion of its petroleum and natural gas exploration activities. Canadian income tax law permits the Company to renounce to the flow-through shareholders the income tax attributes of certain petroleum and natural gas exploration and evaluation costs financed by such shares. A liability is recognized for any premium on the flow-through shares in excess of a regular common share and is subsequently reversed as the Company incurs qualifying the designated Canadian exploration or development expenses.

(h) Income taxes

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

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

Deferred income tax is recognized using the balance sheet liability method, providing for temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred income tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date. Deferred income tax assets and liabilities are offset if there is a legally enforceable right to offset and they relate to income taxes levied by the same tax authority on the same taxable entity, or on different tax entities, but they intend to settle current tax liabilities and assets on a net basis or their tax assets and liabilities will be realized simultaneously.

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

(i) Per share amounts

Basic per share amounts are calculated by dividing the income or loss attributable to common shareholders of the Company by the weighted-average number of common shares outstanding during the period. Diluted income or loss per share is determined by dividing the income or loss attributable to common shareholders by the weighted-average number of shares outstanding adjusted for the effects of dilutive instruments such as options and warrants.

The Company uses the treasury stock method to compute the dilutive effect of stock options and warrants. Under this method the dilutive effect on earnings per share is calculated presuming the exercise of outstanding stock options and warrants. It assumes that proceeds received from the exercise of stock options and warrants would be used to repurchase common shares at the average market price during the year. However, the calculation of diluted loss per share excludes the effects of various conversions and exercise of options and warrants that would be anti-dilutive.

(j) Future accounting pronouncements

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. The Company is currently evaluating the impact that these standards will have on results of operations and financial position.

i) 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, with earlier adoption permitted. The Company has conducted the process of identifying and reviewing sales contracts with customers to determine the extent of the impact, and has determined that this standard will have no impact on net loss.

ii) 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. The Company has determined that IFRS 9 will not result in any material changes to its classification of financial assets or liabilities, nor will it have a material impact to the measurement and carrying value of the Company's financial instruments. The standard will come into effect for annual periods beginning on or after January 1, 2018.

iii) In January 2016, 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 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.

4. 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 cash and cash equivalents, accounts receivable, reclamation deposits, term loan, and accounts payable and accrued liabilities.

The fair values of cash and cash equivalents, 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. The fair value of the term loan is estimated as the present value of future cash flows, discounted at the market rate of interest at the reporting date.

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.

5. 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:

	December 31, 2017	December 31, 2016
Accounts receivable		
Marketing receivables	**$ 1,284,474**	$ 774,366
Trade receivables	**$ 76,437**	$ 88,749
Receivables from joint ventures	**7,297**	45,088
Reclamation deposits	**115,535**	115,535
	$ 1,483,743	$ 1,023,738

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 December 31, 2017, the Company had net debt (current assets less current liabilities excluding fair value of financial instruments, and outstanding Term Loan) of $18,558,361 (December 31, 2016 - $11,827,170), which includes Term Loan (Note 12) of $18,868,500 (December 31, 2016 - $11,247,537). Effective September 15, 2017, the Company repaid and terminated its $12.5 million credit facility with Alberta Treasury Branches (Note 11). The Company funds its operations through production revenue and the Term Loan (Note 12).

(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 $150,000 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 $30,000 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 December 31, 2017, the Company held derivative commodity contracts as follows:

Product	Type	Volume	Price	Index	Term	Dec. 31, 2017 Fair Value
Crude oil	Swap(1)	150 bbl/d	US$54.65	WTI-NYMEX	Nov. 1, 2017 – Jun. 30, 2018	188,617
Crude oil	Swap	300 bbl/d	US$50.67	WTI-NYMEX	Jan. 1, 2018 – Dec. 31, 2018	1,189,728
Crude oil	Option(1)	150 bbl/d	US$54.65	WTI-NYMEX	Jul. 1, 2018 – Feb. 28, 2019	255,121
Crude oil	Swap	250 bbl/d	US$50.67	WTI-NYMEX	Jan. 1, 2019 – Dec. 31, 2019	595,793
Crude oil	Swap	200 bbl/d	US$50.67	WTI-NYMEX	Jan. 1, 2020 – Aug. 1, 2020	194,024
					Total	**$2,423,282**

Note:
(1) The counter-party to this contract holds a one-time option no later than June 30, 2018 to extend a swap on 150 bbl/d of crude oil at US$54.65 for the term indicated.

At December 31, 2017, the commodity contracts were fair valued as a liability of $2,423,282 recorded on the balance sheet, and an unrealized loss of $2,423,282 recorded as revenue for the year ended December 31, 2017.

(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.

6. 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 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, obtaining additional financing from the Company's 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.

7. 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, plant and equipment is made when reserves are assigned or the exploration project has been completed. For the year ended December 31, 2017, the Company transferred $1,898,255 (December 31, 2016 - $99,012) to property, plant and equipment, capitalized general and administrative expenses of $157,564 (December 31, 2016 - $206,160) to exploration and evaluation assets, and recognized exploration and evaluation expense of $576,586 (December 31, 2016 - $246,393), which related to a damaged well and expired lands.

Cost		
Balance, December 31, 2015	$	3,100,937
Additions		504,877
Exploration and evaluation expense		(246,393)
Transfer to property, plant and equipment		(99,012)
Balance, December 31, 2016	$	3,260,407
Additions		4,108,542
Exploration and evaluation expense		(576,586)
Transfer to property, plant and equipment		(1,898,255)
Balance, December 31, 2017	**$**	**4,894,108**

8. Property, Plant and Equipment

		Petroleum and Natural Gas		Other Equipment		Total
Cost						
Balance, December 31, 2015	$	66,010,862	$	114,492	$	66,125,354
Additions		2,217,499		-		2,217,499
Decrease in decommissioning obligations		(1,211,718)		-		(1,211,718)
Capitalized share-based payments		26,893		-		26,893
Transfer from exploration and evaluation assets		99,012		-		99,012
Balance, December 31, 2016	$	67,142,548	$	114,492	$	67,257,040
Additions		4,580,698		-		4,580,698
Change in decommissioning obligations		1,171,705		-		1,171,705
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**	**$**	**75,006,859**
Accumulated Depletion, Depreciation, Amortization and Impairment						
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**
Net Book Value						
December 31, 2016	$	35,212,868	$	29,176	$	35,242,044
December 31, 2017	**$**	**39,872,225**	**$**	**21,799**	**$**	**39,894,023**

The Company's additions for property, plant and equipment included capitalized general and administrative expenses of $228,964 and $84,954 for the years ended December 31, 2017 and 2016, respectively.

The calculation for depletion at December 31, 2017 includes estimated future development costs of $34,424,000 (December 31, 2016 - $22,049,600) associated with the development of the Company's Proved plus Probable reserves.

(a) Property acquisitions for the year ended December 31, 2016:
On October 1, 2016, the Company completed a strategic acquisition of the remaining 20% and 40% working interest in two wells in Jenner for a purchase price of $1.00. The Company now has 100% working interest in this land.

At December 31, 2017, the Company performed an assessment of potential impairment indicators, and management determined that an impairment test on its petroleum and natural gas assets was not required. At December 31, 2016, the Company performed an assessment of potential impairment indicators, and management determined that an impairment test on its petroleum and natural gas assets was not required.

9. 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 December 31, 2017 is $6,746,336 (December 31, 2016 - $5,818,088). These payments are expected to be made over the next 38 years with the majority of costs to be incurred between 2028 and 2056. The discount factor, being the risk-free rate related to the liability, is 2.24% (December 31, 2016 - 2.20%). Inflation of 1.80% (December 31, 2016 – 1.40%) has also been factored into the calculation of amounts in the table below. The Company also has $115,535 (December 31, 2016 - $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.

The change in estimates for the years ended December 31, 2017 and 2016 resulted from the decommissioning obligations being revalued at the year-end risk-free and inflation rates.

	December 31, 2017	December 31, 2016
Decommissioning obligations, beginning of period	**$ 4,896,681**	$ 5,965,233
Increase in estimated future obligations	**847,114**	66,998
Change in estimate	**324,591**	(1,278,716)
Accretion expense	**107,727**	143,166
Decommissioning obligations, end of year	**$ 6,176,112**	$ 4,896,681

10. Finance Expenses

	Year Ended December 31	
	2017	2016
Finance expense:		
Cash Interest expense	**$ 834,078**	$ 538,216
Amortization of deferred charges	**87,837**	-
Accretion of debt issuance costs	**48,738**	-
Accretion of decommissioning liabilities	**107,727**	143,166
Total	**$ 1,078,380**	$ 681,382

11. Bank Indebtedness

Effective September 15, 2017, the Company repaid and terminated its $12.5 million credit facility with Alberta Treasury Branches.

12. 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 of which USD $15.0 million had been drawn as at December 31, 2017 (CAD$18,868,500). The Company's ability to access additional commitments in excess of US$15.0 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	$ 18,530,810	$ -	$ 18,530,810
Foreign exchange adjustment	244,453	-	244,453
Debt issuance costs	(746,074)	(481,983)	(1,228,057)
Value allocated to warrants	(612,409)	(816,545)	(1,428,954)
Amortization of deferred charges	-	87,837	87,837
Accretion of debt issuance costs	48,738	-	48,738
Balance, end of year – liability (asset)	**$ 17,465,518**	**$ (1,210,691)**	**$ 16,254,827**

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.

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 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 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,

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 $2.0 million per annum as at December 31, 2017, and escalating to $2.5 million per annum in 2018 for each year thereafter. The Company recorded $1,971,364 in gross cash G&A costs and was in compliance with its G&A covenant.

13. Share Capital

(a) Authorized

Unlimited number of common shares without par value.

Issued and outstanding

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.

As at December 31, 2017, the Company had 89,793,302 shares issued and outstanding.

(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. Stock options granted on September 21, 2017, and on a go-forward basis, are subject to a vesting schedule whereby one-third vests immediately, one-third vests on the first anniversary, and one-third vests on the second anniversary of the grant date. Stock options granted prior to 2017 all had immediate vesting.

Details of the Company's stock options as at December 31, 2017 and 2016 are as follows:

				Changes in the Year				
Exercise Price	Grant Date	Expiry Date	Balance Outstanding Dec. 31, 2016	Granted	Exercised	Expired	Balance Outstanding Dec. 31, 2017	Balance Exercisable Dec. 31, 2017
$0.70	8-Feb-12	8-Feb-17	1,400,000	-	-	(1,400,000)	-	-
$0.24	29-Jan-15	29-Jan-20	1,075,000	-	-	-	1,075,000	1,075,000
$0.39	1-Mar-15	1-Mar-20	100,000	-	-	-	100,000	100,000
$0.08	11-Feb-16	11-Feb-21	1,685,000	-	-	-	1,685,000	1,685,000
$0.08	12-Feb-16	12-Feb-21	125,000	-	-	-	125,000	125,000
$0.25	21-Sep-17	21-Sep-22	-	5,034,000	-	-	5,034,000	1,678,000
$0.28	2-Oct-17	2-Oct-22	-	150,000	-	-	150,000	50,000
			4,385,000	5,184,000	-	(1,400,000)	8,169,000	4,713,000
Weighted-average exercise price			$0.32	$0.25	-	$0.70	$0.21	$0.19

				Changes in the Year				
Exercise Price	Grant Date	Expiry Date	Balance Outstanding Dec. 31, 2015	Granted	Exercised	Expired	Balance Outstanding Dec. 31, 2016	Balance Exercisable Dec. 31, 2016
$0.30	27-Jan-11	27-Jan-16	200,000	-	-	(200,000)	-	-
$0.38	9-Feb-11	9-Feb-16	50,000	-	-	(50,000)	-	-
$0.40	26-May-11	26-May-16	475,000	-	-	(475,000)	-	-
$0.48	5-Jul-11	5-Jul-16	50,000	-	-	(50,000)	-	-
$0.70	8-Feb-12	8-Feb-17	1,500,000	-	-	(100,000)	1,400,000	1,400,000
$0.65	24-Apr-12	24-Apr-17	75,000	-	-	(75,000)	-	-
$0.61	5-Jul-12	5-Jul-17	425,000	-	-	(425,000)	-	-
$0.50	8-Mar-13	8-Mar-18	250,000	-	-	(250,000)	-	-
$0.55	6-Jan-14	6-Jan-19	660,000	-	-	(660,000)	-	-
$0.65	29-Sep-14	29-Sep-19	785,000	-	-	(785,000)	-	-
$0.61	7-Oct-14	7-Oct-19	200,000	-	-	(200,000)	-	-
$0.24	29-Jan-15	29-Jan-20	1,225,000	-	-	(150,000)	1,075,000	1,075,000
$0.39	1-Mar-15	1-Mar-20	100,000	-	-	-	100,000	100,000
$0.08	11-Feb-16	11-Feb-21	-	1,785,000	(100,000)	-	1,685,000	1,666,250
$0.08	12-Feb-16	12-Feb-21	-	200,000	(75,000)	-	125,000	125,000
			5,995,000	1,985,000	(175,000)	(3,420,000)	4,385,000	4,366,250
Weighted-average exercise price			$0.52	$0.08	$0.08	$0.53	$0.32	$0.33

For the year ended December 31, 2017, the Company recognized $332,669 (December 31, 2016 - $116,604) in share-based payments of which $233,508 (December 31, 2016 - $3,279) was expensed as stock-based compensation and $99,161 (December 31, 2016 - $26,893) was capitalized to property, plant and equipment (December 31, 2016 - $41,097 was capitalized to property, plant and equipment assets). These share-based payments were from the granting of 5,034,000 and 150,000 incentive stock options during the third quarter and fourth quarters respectively (December 31, 2016 – 1,985,000) to directors, officers, employees and consultants of the Company at an exercise price of $0.25 each, of which 1,678,000 and 50,000 vested immediately.

The fair value of the granted stock options was determined using the Black-Scholes option pricing model with the following weighted-average assumptions:

	Year Ended December 31	
	2017	2016
Expected life (years)	**5.00**	5.00
Interest rate	**1.81%**	0.82%
Volatility	**66.18%**	97.20%
Fair value at grant date	**$ 0.14**	$ $0.06

The weighted-average exercise price for stock options granted during the year ended December 31, 2017 was $0.25 (year ended December 31, 2016 - $0.08). The forfeiture rate has been estimated at 5% (December 31, 2016 - 5%).

For the year ended December 31, 2017, the Company removed $875,000 (year ended December 31, 2016 - $1,376,165) from contributed surplus and recorded a corresponding recovery in deficit for expired stock options.

Option pricing models require the input of highly subjective assumptions, including the expected price volatility. Changes in the subjective input assumptions can materially affect the fair value estimate.

(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 12). 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 December 31, 2017, the Company had 13,750,000 outstanding and exercisable share purchase warrants.

(d) Loss per share

	Years Ended December 31	
	2017	2016
Loss for the year	**$ (3,796,176)**	$ (2,680,648)
Weighted-average number of common shares outstanding, basic	**88,495,660**	80,672,032
Dilutive stock options	**-**	-
Weighted-average number of common shares outstanding, diluted	**88,495,660**	80,672,032
Loss per share, basic and diluted	**$ (0.04)**	$ (0.03)

For the years ended December 31, 2017 and 2016, the Company incurred a loss; therefore, dilutive stock options and warrants were nil.

14. Related Party Transactions

Compensation to key executive personnel, consisting of the Company's officers, directors and Chairman, was paid as follows:

	Three Months Ended December 31		Years Ended December 31	
	2017	2016	**2017**	2016
Salaries and wages	**$ 205,000**	$ 210,000	**$ 768,333**	$ 650,167
Share-based payments	**-**	-	**172,575**	76,334

15. Commitment

		2018	2019	2020	2021	2022	Total
Office Rental	$	149,946	138,676	138,676	138,676	138,676	704,649
Term Loan		-	-	-	-	18,868,500	18,868,500
Term Loan Interest		1,664,202	1,664,202	1,664,202	1,664,202	1,180,317	7,837,124
	$	1,814,148	1,802,877	1,802,877	1,802,877	20,187,493	27,410,273

The Company has a commitment to make monthly rental payments pursuant to the office rental agreement at its current location until May 30, 2018. The Company has a commitment to make monthly rental payments pursuant to the office rental agreement at its new location commencing June 1, 2018 until May 30, 2023.

On April 27, 2017, the Company issued 4,048,200 Canadian Development Expense flow-through shares at $0.28 per share for gross proceeds of $1,133,496 which had a commitment to be expended pursuant to the provisions of the *Income Tax Act* (Canada) by December 31, 2017 (Note 13). As at December 31, 2017, the Company has expended its commitment and recorded a deferred tax recovery of $161,928.

As at December 31, 2017, the gross balance of the Term Loan was $18,868,500 (US$15,000,000), exclusive of the debt issuance costs. The Term Loan matures on September 15, 2022.

16. Supplemental Cash Flow Information

		Year Ended December 31		
		2017		2016
Provided by (used in):				
Accounts receivable	**$**	**(460,005)**	$	(368,874)
Prepaid expenses		**(44,431)**		(22,277)
Accounts payable and accrued liabilities		**987,655**		352,713
Total changes in non-cash working capital	**$**	**483,219**	$	(38,438)
Provided by (used in):				
Operating activities	**$**	**(560,801)**	$	(97,963)
Investing activities		**1,044,020**		59,525
Total changes in non-cash working capital	**$**	**483,219**	$	(38,438)

Cash interest paid on the Company's debts during the year ended December 31, 2017 was $834,078 compared to $538,216 for the year ended December 31, 2016.

17. Income Taxes

The reconciliation of income tax computed at the current statutory tax rate of 26.55% (year ended December 31, 2016 – 26.54 to income tax expense is:

		Year Ended December 31		
		2017		2016
Income (loss) before income taxes	**$**	**(4,343,921)**	$	(2,680,647)
Statutory income tax rate		**26.55%**		26.54%
Expected income tax expense (recovery)		**(1,153,739)**		(711,528)
Non-deductible items		**63,166**		29,138
Over and under provided in prior year		**(20,328)**		-
Effect of change in tax rate and other		**(84,797)**		13,151
Amounts renounced on flow-through		**144,116**		116,872
Unused tax losses and tax offsets not recognized		**503,836**		486,967
Deferred tax expense	**$**	**(547,746)**	$	(65,400)

The combined deferred tax rate has increased from 26.55% to 27% as a result of the increase in the British Columbia tax rate from 11% to 12% effective January 1, 2018.

The tax affected items that give rise to significant portions of the deferred tax asset at December 31, 2017 and 2016 are presented below:

	December 31, 2017	December 31, 2016
Deferred tax assets		
Non-capital losses	**$ 3,218,319**	$ 1,746,358
Share issue costs	**49,651**	121,286
Decommissioning obligations	**1,667,551**	1,299,733
Financial Instruments	**654,286**	-
	5,589,807	3,167,377
Deferred income tax liability		
Property and equipment	**(4,975,292)**	(3,167,377)
Term Loan	**(614,515)**	-
	$ -	$ -

The Company assessed the probability that future taxable profit will be available against which the Company can utilize the benefits of tax pools in excess of the carrying amount of assets and has not recognized a deferred tax asset in respect of the following deductible temporary differences.

	December 31, 2017	December 31, 2016
Net-capital loss carryforwards	**95,333**	95,333
Non-capital losses	**15,319,328**	14,543,119
Share issue cost	**143,182**	124,526
Debt issue cost	**982,446**	-
	$ 16,540,289	$ 14,762,978

As at December 31, 2017, the Company has non-capital losses of approximately $27,239,030 that may be applied to reduce future Canadian taxable income, expiring as follows:

Available to	
2026	$ 546,873
2027	340,994
2028	215,784
2029	311,713
2030	323,389
2031	556,859
2032	1,736,206
2033	2,540,111
2035	7,173,180
2036	7,644,779
2037	5,849,142
	$ 27,239,030

18. Subsequent Events

a) On January 1, 2018, the Company granted a consultant 250,000 stock options at an exercise price of $0.25 per share of which one-third vested immediately, one-third vests on the first anniversary, and one-third vests on the second anniversary of the grant date.

b) On January 23, 2018, the Company amended its term loan with its Lender with an increase to the commitment by US$5.0 million, bringing the aggregate amount committed by the Lender under the Term Loan to US$20.0 million.

c) Subsequent to the year end, the Company entered into the following commodity price contracts:

Product	Type	Volume	Price	Index	Term
Crude oil	Swap	100 bbl/d	US$21.90	WCS	April 1, 2018 - September 30, 2018
Crude oil	Swap	400 bb/d	US$18.45	WCS	May 1, 2018 – September 30, 2018
Crude oil	Collar	130 bbl/d	US$40.00-US$74.50	WTI-NYMEX	March 1, 2019 – December 31, 2019
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

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

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