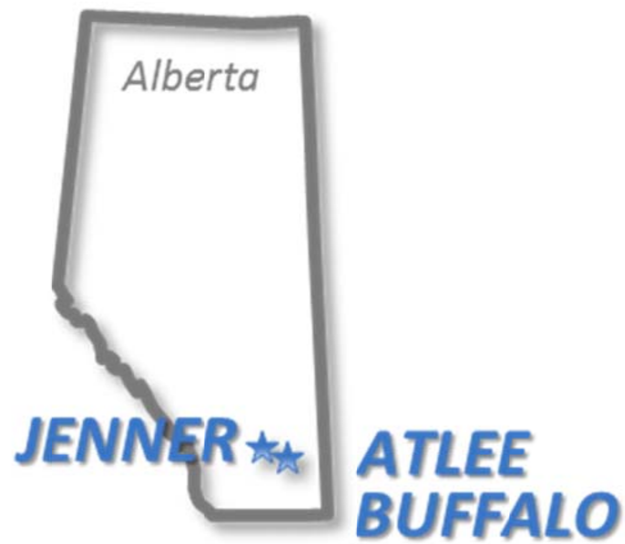
Hemisphere
energy corporation

ANNUAL REPORT

2015

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 drilling existing projects and executing strategic acquisitions. Hemisphere trades on the TSX Venture Exchange as a Tier 1 issuer under the symbol "HME".



2016 Annual General and Special Meeting of Shareholders

June 10, 2016 at 9:00 am Pacific Daylight Time
Oceanic Plaza, Pender Room
1035 West Pender Street, Vancouver, British Columbia

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2015 FINANCIAL AND OPERATING HIGHLIGHTS

	Year Ended December 31			
		2015		2014
FINANCIAL				
Petroleum and natural gas revenue	**$**	**9,749,377**	$	16,635,279
Petroleum and natural gas netback		**5,335,096**		9,275,653
Funds flow from operations(1)		**3,188,485**		6,863,919
Per share, basic and diluted		**0.04**		0.10
Loss before tax(2)		**(6,668,915)**		(1,907,495)
Net loss		**(8,310,831)**		(1,667,807)
Per share, basic and diluted		**(0.11)**		(0.02)
Capital expenditures, including property acquisitions		**3,086,147**		21,316,366
Net debt(3)		**11,446,110**		11,644,609
Bank indebtedness	**$**	**10,828,040**	$	7,184,147

OPERATING				
Average daily production				
Oil (bbl/d)		**607**		583
Natural gas (Mcf/d)		**1,003**		593
NGL (bbl/d)		**2**		2
Combined (boe/d)		**776**		683
Oil and NGL weighting		**78%**		86%
Average sales prices				
Oil ($/bbl)	**$**	**39.61**	$	73.87
Natural gas ($/Mcf)		**2.61**		4.08
NGL ($/bbl)		**21.28**		54.85
Combined ($/boe)	**$**	**34.41**	$	66.68
Operating netback ($/boe)				
Petroleum and natural gas revenue	**$**	**34.41**	$	66.68
Royalties		**2.73**		12.05
Operating costs		**10.06**		14.10
Transportation costs		**2.79**		3.34
Operating netback(4)	**$**	**18.83**	$	37.19

Notes:

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

(2) The Company does not anticipate its deferred tax asset will be realized in the near future; as a result the Company has provided for it in the amount of $1,641,916 for the year ended December 31, 2015.

(3) Net debt is a non-IFRS measure calculated as current assets minus current liabilities including bank indebtedness and excluding flow-through share premium.

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

	As at December 31	
	2015	2014
RESERVES		
Proved (Mboe)	**2,785.1**	2,193.1
Proved plus Probable (Mboe)	**3,933.9**	3,337.5
COMMON SHARES		
Common shares outstanding	**75,803,498**	75,368,498
Stock options outstanding	**5,995,000**	5,970,000
Weighted-average shares outstanding – basic and diluted	**75,758,868**	70,075,412

MESSAGE TO SHAREHOLDERS

Dear Fellow Shareholders,

Last year was an extremely challenging year for the oil and gas industry and as a result Hemisphere adjusted its game plan. Seeing the continued volatility in oil prices, Hemisphere focused on reducing administration and operating costs while at the same time developing our assets to maximize reserve additions with minimal capital spending. Corporate annual production averaged 776 boed (80% oil), representing an increase of 14% over the previous year. Funds flow from operations was $3.2 million for the year and provided Hemisphere the capital to execute its development plan.

Through the year Hemisphere focused on its core Jenner and Atlee Buffalo properties in southeastern Alberta. Management determined that the implementation of three enhanced oil recovery pilot projects in Atlee Buffalo and the addition of fluid handling capacity in Jenner was the best approach to maximize return on capital and yield reserve additions at the lowest finding and development costs (F&D) possible. Hemisphere is ready to quickly execute its development drilling programs in both Atlee Buffalo and Jenner when prices recover, but has no requirements to accelerate this program prior to a stabilization of market pricing that will ensure appropriate payouts and rates of return on capital employed.

With only $2.4 million spent on development capital through 2015, Hemisphere increased our proved developed producing reserves by 49% at an actual 2015 F&D of $2.99/boe (excluding changes in future development costs), and replaced over 300% of our production with proved plus probable reserve growth to 3.9 million barrels of oil equivalent (95% oil).

Much of our 2015 reserve additions came from the recognition of extensive potential in the enhanced oil recovery projects implemented last year in Atlee Buffalo. Final approvals for all three pilot waterfloods were received by late October and injection commenced by November. At such early stages in waterflood implementation for the Company, Hemisphere's year-end 2015 reserve bookings have been based on conservative total recovery factors as compared to those already achieved at surrounding analogue pools. A 12% total pool recovery factor in the Upper Mannville F pool (7 producing wells) and 4% total pool recovery factor in the Upper Mannville G pool (no producing wells yet drilled) are currently recognized for Hemisphere's proved plus probable booked reserves as of December 31, 2015. Hemisphere is committed to proving the economic viability of waterfloods in both of these pools so that considerable unbooked reserve value can be recognized with further development in the coming years should the waterflood continue to perform in a similar manner to the analogue pools.

In Jenner, Hemisphere constructed a pipeline from its main facility to an underutilized water disposal well during the fourth quarter of 2015. The additional fluid handling increased Hemisphere's disposal capacity and will allow existing wells to be optimized. Better than expected production performance in Jenner resulted in upward technical revisions, which yielded a 148% replacement of proved developed reserves year over year.

Over the past eighteen months our industry has faced challenges with the substantial decline in oil prices as a result of global supply exceeding demand. As a response to this lower price environment the oil and gas industry has cut capital spending programs which are resulting in production declines and a rebalancing of the oil market. Hemisphere believes that the industry is starting to see the results of this reduced activity in the market today with the recent increase in oil price and that going forward, companies with low operating and F&D costs, strong assets, and diligent capital spending strategies will outperform their competitors. Hemisphere's assets, with large estimated accumulations of fully delineated oil in place and current low recovery factors, provide an excellent opportunity for low risk growth through the bread-and-butter approach of horizontal development wells and enhanced recovery through waterflooding that has been used since the very early days of oil and gas development.

I would like to express my gratitude to the Hemisphere Team for their continued hard work, dedication, and commitment to the company, which remained resilient and successful during the most challenging year seen in our industry in decades. I would also like to personally thank all our shareholders for their continued support and confidence in Hemisphere as we continue to develop our 100% owned and operated assets that provide significant future growth opportunities as prices recover.

Best regards,

(Signed) *"Don Simmons"*
Don Simmons, P.Geol.
President & Chief Executive Officer
April 26, 2016

Please refer to the attached Management's Discussion and Analysis for Reader Advisories regarding forward-looking information, non-IFRS and additional IFRS measures and oil and gas measurements. 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, 2015, 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, 2016

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, 2015 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, 2015 and 2014. 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, additional IFRS measures and forward-looking statements. Readers are cautioned that this document should be read in conjunction with Hemisphere's disclosure under "Non-IFRS and Additional IFRS Measures" and "Forward-Looking Statements" included at the end of this MD&A. All figures are in Canadian dollars unless otherwise noted. Tables may not add due to rounding. Certain prior period amounts may have been reclassified to conform to the current period's presentation.

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 an average working interest of 92% in 26,066 net acres and has continued to build a land position in the Jenner area through Crown landsales 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 7,200 net acres and has been building a land position in Atlee Buffalo through Crown landsales and strategic acquisitions since 2013.

During the year, the Company strategically acquired 2.5 sections of land in a Crown landsale for approximately $64,000. These acquired lands include key surrounding areas of the Company's Atlee Buffalo Upper Mannville F and G pools and has brought the Company's land ownership to 100% over both pools. The Company also completed a strategic tuck-in acquisition of the remaining 15% working interest in 1.75 sections (1,120 acres) of land in Atlee Buffalo for a purchase price of $250,000. The Company now has 100% working interest in this land.

Operating Results

The Company generated funds flow from operations of $3,188,486 ($0.04/share) for the year ended December 31, 2015, as compared to $6,863,919 ($0.10/share) for the year ended December 31, 2014. For the fourth quarter of 2015, the Company generated negative funds flow from operations of $103,531 ($0.00/share) as compared to positive funds flow from operations of $1,433,394 ($0.02/share) for the fourth quarter of 2014.

The Company realized decreases in funds flow from operations for the three months and year ended December 31, 2015 over the comparable periods in 2014 as a result of the decline in commodity prices.

The Company reported a net loss of $8,310,831 ($0.11/share) for the year ended December 31, 2015 that included a deferred tax expense of $1,641,916 as compared to a net loss of $1,667,807 ($0.02/share) for the year ended December 31, 2014 that included a deferred tax recovery of $239,688. For the fourth quarter of 2015, the Company reported a net loss of $2,333,468 ($0.03/share) compared to a net loss of $3,568,603 ($0.05/share) for the fourth quarter of 2014.

Production

	Three Months Ended December 31		Year Ended December 31	
By product	**2015**	2014	**2015**	2014
Oil (bbl/d)	**440**	763	**607**	583
Natural gas (Mcf/d)	**879**	720	**1,003**	593
NGL (bbl/d)	**2**	3	**2**	2
Total (boe/d)	**588**	885	**776**	683
Oil and NGL weighting	**75%**	86%	**78%**	86%

In the fourth quarter of 2015, the Company's average daily production was 588 boe/d (75% oil and NGL). This decrease in production from the comparable quarter of 2014 is the result of converting two producing wells in Atlee Buffalo to injectors during the third quarter of 2015 and production downtime while workovers were performed on four producing wells during the quarter. The Company's average daily production for the year ended December 31, 2015 increased by 14% over 2014 to 776 boe/d (78% oil and NGL). This increase is the result of realizing a full year of production from the successful development of the Company's Atlee Buffalo and Jenner properties in 2014 and the optimization of production from existing wells during 2015.

During the third quarter of 2015, the Company converted two producing wells in the Upper Mannville F pool in Atlee Buffalo to injectors as part of the Company's waterflood pilot project. Based on production rates from the third quarter of 2015, the conversion of these wells reduced the Company's production by approximately 35 boe/d for the current quarter. Although the conversions have impacted the Company's production in the short-term, the conversions were essential to increasing the future oil recovery from this pool and adding to the Company's reserves.

Workovers were also performed on four wells in the fourth quarter of 2015 which resulted in a combined production shortfall of approximately 12 boe/d for the quarter. Lastly, the Company experienced some production downtime in Trutch as two gas wells were shut-in for two months of the quarter due to a facility turnaround, resulting in lost production of approximately 6 boe/d.

Average Benchmark and Realized Prices

	Three Months Ended December 31		Year Ended December 31	
	2015	2014	**2015**	2014
Benchmark Prices				
WTI (US$/bbl)[1]	**$ 42.18**	$ 73.15	**$ 48.80**	$ 93.00
Exchange rate (1 US$/C$)	**1.3347**	1.1361	**1.2764**	1.1045
WTI (C$/bbl)	**56.30**	83.10	**62.29**	102.71
WCS (C$/bbl)[2]	**36.86**	66.77	**44.83**	81.11
AECO natural gas ($/Mcf)[3]	**2.43**	3.57	**2.65**	4.41
Average realized prices				
Crude oil ($/bbl)	**31.99**	61.66	**39.61**	73.87
Natural gas ($/Mcf)	**2.41**	3.52	**2.61**	4.08
NGL ($/bbl)	**20.81**	39.72	**21.28**	54.85
Combined ($/boe)	**$ 27.59**	$ 56.10	**$ 34.41**	$ 66.68

Notes:

(1) Represents posting prices of West Texas Intermediate Oil.

(2) Represents posting prices of Western Canadian Select.

(3) Represents the Alberta 30 day spot AECO posting prices.

The Company's oil and natural gas sales and financial results are significantly influenced by changes in commodity prices. The West Texas Intermediate pricing ("WTI") at Cushing, Oklahoma is the benchmark reference price for North American crude oil prices. Canadian oil prices, including the Company'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 average realized oil price for the three months and year ended December 31, 2015 decreased by 48% and 46%, respectively, from the comparable periods in 2014 which correlates to the combined impact of a lower WTI. WTI began falling in late 2014 and has remained low throughout 2015 and into 2016 as a result of a supply-demand imbalance of oil in the global market. The exchange rate remained favourable in the fourth quarter of 2015 and is expected to remain favourable through the first quarter of 2016 due to the low Canadian dollar.

The Company's average realized natural gas price decreased for the three months and year ended December 31, 2015 by 32% and 36%, respectively, from the comparable periods in 2014. These decreases correlate to AECO benchmark pricing for the three months and year ended December 31, 2015 which showed a decline of 32% and 40%, respectively, over the comparable periods of 2014.

The Company's combined average realized price decreased by 51% to $27.59/boe during the fourth quarter of 2015 from $56.10/boe during the fourth quarter of 2014. For the year ended December 31, 2015, the Company's combined average realized price decreased by 48% to $34.41/boe. These decreases are primarily the result of the decline in WTI which has extended throughout 2015.

The Company does not currently have any production hedged.

Revenue

	Three Months Ended December 31		Year Ended December 31	
	2015	2014	**2015**	2014
Oil	**$ 1,295,544**	$ 4,326,223	**$ 8,776,389**	$ 15,717,054
Natural gas	**194,635**	232,914	**956,661**	883,776
NGL	**3,134**	9,149	**16,327**	34,449
Total	**$ 1,493,313**	$ 4,568,286	**$ 9,749,377**	$ 16,635,279

Revenue for the three months and year ended December 31, 2015 decreased by 67% and 41%, respectively, from the comparable periods in 2014. These decreases in revenue can be attributed to the reductions in the Company's combined average realized price for the quarter and year ended December 31, 2015 as well as the Company's lower production rate in the fourth quarter of 2015. The Company's combined average realized price for the three months and year ended December 31, 2015 decreased by 51% to $27.59/boe and 48% to $34.41/boe, respectively.

Operating Netback

	Three Months Ended December 31		Year Ended December 31	
	2015	2014	**2015**	2014
Operating netback				
Revenue	**$ 1,493,313**	$ 4,568,286	**$ 9,749,377**	$ 16,635,279
Royalties	**162,564**	783,898	**774,798**	3,008,377
Operating costs	**730,570**	948,519	**2,849,900**	3,516,956
Transportation costs	**141,939**	301,535	**789,583**	834,292
Operating netback	**$ 458,240**	$ 2,534,334	**$ 5,335,096**	$ 9,275,653
Operating netback ($/boe)				
Revenue	**$ 27.59**	$ 56.10	**$ 34.41**	$ 66.68
Royalties	**3.00**	9.60	**2.73**	12.05
Operating costs	**13.50**	11.65	**10.06**	14.10
Transportation costs	**2.62**	3.70	**2.79**	3.34
Operating netback ($/boe)	**$ 8.47**	$ 31.15	**$ 18.83**	$ 37.19

Royalties for the fourth quarter of 2015 were $3.00/boe, representing a 69% decrease from the fourth quarter of 2014. For the year ended December 31, 2015, royalties decreased by 77% from the comparable period in 2014. These significant reductions are partially the result of 12 new horizontal wells drilled in 2014 which have lower associated royalty rates on initial production with an 18 month Crown royalty holiday. As at December 31, 2015, six of these 12 wells are still subject to the royalty holiday. Crown royalties have also decreased as a result of two retroactive Crown royalty rebates received in the first half of 2015, as well as lower individual well production in combination with a low Crown royalty par price. As Crown royalty par price is set based on commodity prices, the Company expects to see low Crown royalties in the first half of 2016 given the current commodity pricing environment.

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 increased for the three months ended December 31, 2015 by $1.85/boe which is a direct result of five workovers performed in the quarter representing $1.43/ boe of operating costs during the fourth quarter of 2015. Operating costs decreased for the year ended December 31, 2015 by $4.04/boe from the comparable period in 2014. This decrease is the result of higher production levels in Atlee Buffalo which have lower operating costs per boe, as well as realized economies of scale as a result of production from new wells drilled in 2014. The Company has also shut-in a number of wells with high operating costs and implemented cost control measures in order to maximize operating netback and cash flow for the period. The Company has worked with its field operators to lower labour and material costs, and has optimized field operations by internally conducting routine field repairs and activities rather than contracting externally.

Transportation costs include all costs incurred to transport emulsion and oil and gas sales to processing and distribution facilities. Transportation costs decreased for the three months and year ended December 31, 2015 by $1.08/boe and $0.56/boe, respectively, from the comparable periods in 2014. These decreases are the result of the Company's voluntary shut-in of four high water-cut wells that require trucking to facilities for processing. Transportation costs for the three months ended December 31, 2015 also decreased by 5% from the third quarter of 2015 to $2.62/boe.

Operating netback for the three months and year ended December 31, 2015 was $8.47/boe and $18.83/boe, respectively. The Company experienced decreases in operating netback in 2015 as a result of the significant decline in commodity prices, despite reductions in royalties and the Company's diligent efforts in cutting operating costs. In this challenging commodity pricing environment, the Company continues to focus on reducing field operating expenses through operational efficiencies, cutting costs, and optimizing economic wells in order to preserve operating netback and funds flow from operations.

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 decreased for the three months and year ended December 31, 2015 decreased by $17,599 and $91,915, respectively, from the comparable periods of 2014. Exploration and evaluation expense for the three months and year ended December 31, 2015 were the result of several land expiries which occurred in 2015.

Depletion and Depreciation

	Three Months Ended December 31		Year Ended December 31	
	2015	2014	**2015**	2014
Depletion expense	**$ 794,440**	$ 2,412,265	**$ 5,107,250**	$ 5,353,585
Depreciation expense	**3,364**	2,401	**13,455**	7,404
Total	**$ 797,804**	$ 2,414,666	**$ 5,120,705**	$ 5,360,989
$ per boe	**$ 14.74**	$ 29.65	**$ 18.07**	$ 21.49

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 2015 decreased by $1,616,862 over the fourth quarter of 2014. For the year ended December 31, 2015, depletion and depreciation expense decreased by $240,284 over the comparable period in 2014. These decreases are mainly the result of the Company's remaining recoverable Proved and Probable reserves determined at December 31, 2015, which increased by 11% over the comparable period in 2014. This change lowered the Company's overall depletion rate by 9% as compared to the depletion rate used at December 31, 2014.

The depletion rate is applied to the Company's depletable asset carrying value which, for the twelve months ended December 31, 2015, decreased by 13% over the comparable period in 2014. The Company's depletable asset carrying value consists of the capital expenditures spent in the area along with any FDC required to develop and produce undeveloped and non-producing reserves. The decrease is in line with the Company's reduced capital expenditures of 86% in 2015 and the reduction in the Company's FDC by 21% as compared to 2014.

Capital Expenditures

	Three Months Ended December 31		Year Ended December 31	
	2015	2014	**2015**	2014
Land and lease	**$ 13,264**	$ 46,356	**$ 111,412**	$ 311,092
Geological and geophysical	**88,382**	1,080,890	**321,604**	1,747,813
Drilling and completions	**119,481**	3,923,713	**1,197,071**	13,254,809
Investment in facilities	**518,015**	1,880,248	**1,185,061**	5,370,943
Exploration and Development capital	**739,141**	6,931,208	**2,815,147**	20,684,657
Property acquisitions	**-**	-	**271,000**	634,739
Fixed assets	**-**	-	**-**	46,970
Disposition proceeds	**-**	-	**-**	(50,000)
Total capital expenditures[1]	**$ 739,141**	$ 6,931,208	**$ 3,086,147**	$ 21,316,366

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

The majority of the Company's development capital in the fourth quarter of 2015 was spent on the construction of a new pipeline at the Jenner facility to an existing disposal well. The construction of this pipeline has increased the water injection rate by 700 m3 per day which will increase the Company's production levels in the short-term while also contributing to long-term reserve additions. This project was completed on time and under budget.

The development capital costs for the year ended December 31, 2015 also included the conversion of five wells into three injectors and two water source wells and the construction of a water source pipeline as part of the Atlee Buffalo Upper Mannville F and G pool waterflood pilots. The implementation of these projects was completed on budget at approximately $1.1 million and on schedule with injection having commenced earlier than anticipated. During the year, the Company strategically acquired 2.5 sections of key land in Atlee Buffalo through a Crown landsale. The Company also completed a strategic tuck-in acquisition of the remaining 15% working interest in 1.75 sections (1,120 acres) of land in Atlee Buffalo for proceeds of $250,000. This acquired land brings the Company's land ownership to 100% over both of the Atlee Buffalo Upper Mannville F and G pools.

Hemisphere has taken a conservative approach to capital spending and investment in 2015 as a result of the current commodity pricing environment. The Company will continue to limit expenditures to essential projects and carefully selected land acquisitions until oil prices improve.

General and Administrative Expense ("G&A")

	Three Months Ended December 31		Year Ended December 31	
	2015	2014	**2015**	2014
Gross G&A	**$ 535,134**	$ 1,174,466	**$ 2,063,267**	$ 2,674,693
Capitalized G&A	**(90,234)**	(128,901)	**(363,753)**	(472,530)
Total	**$ 444,900**	$ 1,045,565	**$ 1,699,514**	$ 2,202,163
$ per boe	**$ 8.22**	$ 12.84	**$ 6.00**	$ 8.83

Gross G&A for the fourth quarter of 2015 decreased by 54% from the comparable quarter in 2014 due to the Company's elimination of annual bonuses, decreased use of professional and consulting services, reduced investor relations and marketing activities, and decreased travel expenditures. Gross G&A for the twelve months ended December 31, 2015 decreased by 23% from the comparable period of 2014.

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 three months and year ended December 31, 2015, capitalized G&A decreased by 30% and 23%, respectively, from the comparable periods in 2014. These decreases in capitalized G&A are in line with lower compensation, consulting fees and overhead costs that would have been attributable to the Company's capital activities for the three months and year ended December 31, 2015.

For the three months and year ended December 31, 2015, the Company realized decreases in total G&A by $4.62/boe and $2.83/boe, respectively, from the comparable periods in 2014.

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, 2015 and 2014, the Company recorded share-based payments of $181,580 and $452,780, respectively, which represents a decrease of $271,200. This decrease is the result of a lower number of stock options issued in 2015 as compared to the previous year and the Company capitalizing $41,097 in share-based payments in the third quarter of 2015, which were directly related to the Company's development and exploration activities in the year.

The Company granted 25,000 incentive stock options in the first quarter of 2015 to an individual performing investor-related services which will vest quarterly over a twelve-month period. In the fourth quarter of 2015, 6,250 stock options vested resulting in the recognition of $375 in share-based payments.

Impairment of Property and Equipment

At each reporting date, the Company assesses its petroleum and natural gas properties and exploration and evaluation assets for possible impairment, to determine if there is any indication that the carrying amounts of the assets may not be recoverable. Impairment is recorded when the recoverable amount of an asset is less than the respective carrying amount. The recoverable amounts of the cash-generating units ("CGU") were determined with fair value less costs to sell based on expected future cash flows from Proved plus Probable reserve value, using discount rates specific to the underlying composition of assets residing in each CGU.

The prolonged reduction in crude oil and natural gas prices and deferred capital development plans were recognized by the Company as indicators of impairment at year-end. Lower commodity prices and the deferred development of properties have the effect of lowering the estimated future cash flows of CGUs and the carrying value of CGUs.

The recoverable amounts of the Company's CGUs were estimated based on the higher of the value in use and the fair value less costs to sell. The recoverable amount for the year ended December 31, 2015 was determined using value in use, based on the net present value of the before tax cash flows from oil and natural gas proved plus probable reserves estimated by the Company's external reserve evaluators discounted at a pre-tax rate of 10% to 15% per annum (2014 – 10%).

A decrease in the West Texas Intermediate ("WTI") and Western Canadian Select ("WCS") future oil price estimates combined with a decrease in the future AECO natural gas price as compared to those used in the December 31, 2014 estimates has resulted in impairment charge of $4,366,257 on the Company's developed and producing assets for the year ended December 31, 2015 as compared to $2,702,925 for the year ended December 31, 2014. Impairment charges related to Jenner and Non-core CGUs for $4,336,170 and $30,087 respectively, due to the carrying value exceeding its recoverable amount. After impairment the recoverable amount of the Jenner CGU was $16,802,308, and the Non-core CGUs were $nil.

Finance Expense

	Three Months Ended December 31		Year Ended December 31	
	2015	2014	**2015**	2014
Finance expense				
Interest expense	**$ 116,870**	$ 54,794	**$ 447,096**	$ 197,682
Part XII.6 tax	-	581	-	11,889
Accretion of provision	**31,066**	40,516	**124,263**	66,776
Total finance expense	**$ 147,936**	$ 95,891	**$ 571,358**	$ 276,347
$ per boe	**$ 2.73**	$ 1.18	**$ 2.02**	$ 1.11

Finance expense for the three months and year ended December 31, 2015 increased by $52,045 and $295,012, respectively, over the comparable periods in 2014. These increases are the result of the interest expense incurred on the utilization of the Company's credit facility which carried a higher balance in 2015 as compared to 2014 as well as the accretion expense incurred for the period.

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, 2015, accretion expense was $31,066 and $124,263, respectively. The increases in accretion expense in 2015 over the comparable periods of 2014 are a result of the decommissioning obligations associated with the 12 new wells drilled and 14 wells acquired during the 2014 year.

Tax Pools and Deferred Taxes

The Company has approximately $47 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 2015. Taxes payable beyond 2015 will primarily be a function of commodity prices, capital expenditures and production volumes.

	Deduction Rate	**December 31, 2015**	December 31, 2014
Canadian exploration expense (CEE)	100%	**$ 3,336,823**	$ 3,336,823
Canadian development expense (CDE)	30%	**19,220,505**	24,371,718
Canadian oil and gas property expense (COGPE)	10%	**7,517,421**	8,352,690
Non-capital losses carry forwards (NCL)	100%	**13,734,893**	6,571,929
Undepreciated capital cost (UCC)	20-55%	**2,171,731**	2,870,328
Share issuance costs and other	Various	**797,356**	1,591,613
Total		**$ 46,778,729**	$ 47,095,101

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, 2015		Year Ended December 31, 2014		Year Ended December 31, 2013
Average daily production (boe/d)		**776**		683		463
Petroleum and natural gas revenue	**$**	**9,749,377**	$	16,635,279	$	10,573,199
Petroleum and natural gas netback		**5,335,096**		9,275,653		5,607,492
Funds flow from operations(1)		**3,188,486**		6,863,919		3,789,202
Per share, basic and diluted		**0.04**		0.10		0.07
Net loss(2)		**(8,310,831)**		(1,667,807)		(510,266)
Per share, basic and diluted		**(0.11)**		(0.02)		(0.01)
Average realized price ($/boe)		**34.41**		66.68		62.55
Operating netback ($/boe)(3)		**18.83**		37.19		33.17
Capital expenditures, including property acquisitions		**3,086,147**		21,316,366		9,969,174
Net debt(4)		**11,446,110**		11,644,609		6,330,906
Bank indebtedness		**10,828,040**		7,184,147		4,500,000
Total assets(2)		**40,811,044**		48,951,632		32,195,577

Notes:

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

(2) Certain annual amounts were restated retrospectively for December 31, 2013 due to a change in accounting policy as disclosed in Note 4 of the Company's audited annual financial statements for the year ended December 31, 2014.

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

(4) Net debt is a non-IFRS measure calculated as current assets minus current liabilities including bank indebtedness and excluding flow-through share premium.

Summary of Quarterly Results

	2015				2014			
	Dec. 31 Q4(2)	Sep. 30 Q3(3)	Jun. 30 Q2(4)	Mar. 31 Q1(5)	Dec. 31 Q4(6)	Sep. 30 Q3(7)	Jun. 30 Q2(8)	Mar. 31 Q1(9)
Average daily production (boe/d)	**588**	678	849	995	885	725	553	567
Petroleum and natural gas revenue	**1,493,313**	2,043,781	3,284,020	2,928,264	4,568,286	4,703,496	3,799,461	3,564,036
Petroleum and natural gas netback	**458,240**	1,094,625	1,954,246	1,827,986	2,534,334	2,852,204	2,011,113	1,878,003
Funds flow from operations	**(103,531)**	714,505	1,320,981	1,256,531	1,433,394	2,330,091	1,563,174	1,537,260
Per share, basic and diluted	**(0.00)**	0.01	0.02	0.02	0.02	0.03	0.02	0.02
Net income (loss)(1)	**(2,333,468)**	(4,755,531)	(575,484)	(646,345)	(3,568,603)	720,312	554,465	626,019
Basic and diluted income (loss) per share	**(0.03)**	(0.06)	(0.01)	(0.01)	(0.05)	0.01	0.01	0.01
Combined average realized price ($/boe)	**27.59**	32.74	42.49	32.71	56.10	70.52	75.47	69.89
Operating netback ($/boe)	**8.47**	17.54	25.28	20.42	31.14	42.79	39.98	36.83

Notes:

(1) Certain quarterly amounts were restated retrospectively as disclosed in Note 4 of the Company's audited annual financial statements for the year ended December 31, 2014.

(2) Funds flow from operations and petroleum and natural gas netback decreased in this quarter as a result of a 51% reduction in the Company's combined average realized price from the fourth quarter of 2014. The Company also experienced a decrease in production for the quarter as a result of the conversion of two producing wells to injectors as part of the Company's waterflood pilot project. A significant portion of the net loss in this quarter is the result of an impairment charge of $1,353,696 on the Company's developed and producing assets.

(3) *Funds flow from operations and petroleum and natural gas netback decreased in this quarter as a result of a 54% reduction in the Company's combined average realized price. The Company does not anticipate its deferred tax asset will be realized in the near future; as a result it has provided for it in the amount of $1,236,816 in the third quarter of 2015. A significant portion of the net loss in this quarter is the result of an impairment charge of $3,012,561 against the Company's petroleum and natural gas properties.*

(4) *Funds flow from operations and petroleum and natural gas netbacks have shown a slight improvement over the first quarter of 2015 due to a 30% increase in the Company's combined average realized price, but have remained low compared to 2014 as a result of the decline in commodity prices. Due to taxable income generated in excess of tax pools from lower capital expenditures, the Company utilized deferred tax assets resulting in a deferred tax expense of $405,100 for the second quarter of 2015.*

(5) *The decreases in net income, funds flow from operations and petroleum and natural gas netbacks can be attributed to the decrease in the Company's combined average realized price resulting from the decline in oil prices.*

(6) *A significant portion of the loss is due to the $2,702,925 recorded in property impairment and an increase in depletion expense as a result of a change in the Company's depletion accounting policy.*

(7) *Net income can be attributed to a combination of the increase in the Company's production from its summer drilling program and the improvement of netback resulting from decreased operating and transportation costs.*

(8) *The improvement in net income over certain prior quarters is primarily due to the Company's increase in the combined average realized price resulting in higher operating netback.*

(9) *The improvement in net income is primarily due to the Company's increased production levels from the drilling of three new wells and an increase in combined average realized price.*

Outstanding Share Data

	April 26, 2016	**December 31, 2015**	December 31, 2014
Fully diluted share capital			
Common shares issued and outstanding	75,903,498	**75,803,498**	75,368,498
Stock options	5,010,000	**5,995,000**	5,970,000
Total fully diluted	80,913,498	**81,798,498**	81,338,498

Subsequent to December 31, 2015, the following events impacted the Company's share capital:

- On January 27, 2016, 200,000 incentive stock options expired at a price of $0.30.
- On February 9, 2016, 50,000 incentive stock options expired at a price of $0.38.
- On February 11, 2016, the Company granted incentive stock options to officers, directors, employees and consultants of the Company entitling them to purchase up to a total of 1,785,000 common shares at an exercise price of $0.08 each.
- On February 12, 2016, the Company cancelled a total of 2,395,000 incentive stock options granted to certain officers, directors, employees and consultants who voluntarily returned these options to the Company. The cancelled options were granted from April 2012 to October 2014 and were exercisable at prices ranging from $0.50 to $0.65 for a period of five years from the date of grant.
- On February 12, 2016, the Company granted incentive stock options to an employee and consultants of the Company entitling them to purchase up to a total of 200,000 common shares at an exercise price of $0.08 each.
- On April 7, 2016, 100,000 incentive stock options were exercised at a price of $0.08 per share for gross proceeds of $8,000.
- On April 15, 2016, 225,000 incentive stock options were cancelled at exercise prices ranging from $0.24 to $0.70.

The Company has the following stock options that are outstanding and exercisable as at April 26, 2016:

Exercise Price	Expiry Date	Balance Outstanding April 26, 2016	Balance Exercisable April 26, 2016
$0.40	26-May-16	475,000	475,000
$0.70	8-Feb-17	1,400,000	1,400,000
$0.24	29-Jan-20	1,150,000	1,150,000
$0.39	1-Mar-20	100,000	100,000
$0.08	11-Feb-21	1,685,000	1,610,000
$0.08	12-Feb-21	200,000	200,000
		5,010,000	4,935,000
Weighted-average exercise price		$0.33	$0.33

Liquidity and Capital Management

The Company's net debt as at December 31, 2015 and 2014 was $11,446,110 and $11,644,609, respectively, representing a decrease in net debt of $198,501.

a) Financing

The Company's cash provided by financing activities for the year ended December 31, 2015 was $3,752,644, which included an increase in bank indebtedness of $3,643,893. During the year, the Company also issued 435,000 common shares through the exercise of stock options at $0.25 each for gross proceeds of $108,751.

For the year ended December 31, 2014, the Company's cash provided by financing activities was $12,013,775, which included an increase in bank indebtedness of $2,684,147. During the 2014 year, the Company also closed a bought-deal equity financing on May 14, 2014 consisting of 13,333,500 common shares at a price of $0.75 per common share for aggregate gross proceeds of $10,000,125. For the year ended December 31, 2014, the Company issued 690,000 common shares for the exercise of incentive stock options at various prices for gross proceeds of $220,850. Additionally, the Company issued 37,500 common shares from the exercise of share purchase warrants at a price of $0.75 for gross proceeds of $28,125.

b) Capital Resources

The Company has a demand operating credit facility in the amount of $15.0 million with Alberta Treasury Branches ("ATB") which was renewed in July 2015. Funds available under the credit facility are restricted to $14.0 million and access to the remaining $1.0 million is based on additional approval from ATB.

The facility is secured by a general security agreement and a floating charge on all lands of the Company. The facility bears interest at the bank's prime rate plus 1.75%, as well as a standby charge for any undrawn funds. As the available lending limits of the facilities are based on the bank's interpretation of the Company's reserves and future commodity prices, there can be no assurance as to the amount of available facilities that will be determined at each scheduled review. The Company is currently conducting its review with ATB, which it expects to have completed in the May 2016.

Pursuant to the terms of the credit facility, the Company has provided a financial covenant that at all times its working capital ratio shall not be less than 1.0. The working capital ratio is defined under the terms of the credit facilities as current assets including the undrawn portion of the revolving operating demand line credit facility ($14.0 million), to current liabilities, excluding any current bank indebtedness.

At December 31, 2015, the Company has drawn a total of $10,828,040 from the credit facility (December 31, 2014 - $7,184,147) and had a working capital ratio of 3.0, which is in compliance with the above financial covenant.

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 net debt. The Company may manage its capital structure by issuing new shares, repurchasing outstanding shares, obtaining additional financing from the Company's credit facilities, issuing new debt instruments, 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

During the three months and year ended December 31, 2015, the Company paid fees of $10,000 and $40,000, respectively, to a director of the Company. These fees were charged for services provided by the Chairman of the Company's Board of Directors.

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

	Three Months Ended December 31		Year Ended December 31	
	2015	2014	**2015**	2014
Short-term benefits	**$ 205,000**	$ 502,500	**$ 820,000**	$ 986,666
Share-based payments	-	49,723	**135,660**	377,743

Short-term benefits, which are primarily salaries and wages, have decreased during the three months and year ended December 31, 2015 as a result of the elimination of annual bonuses in the year.

Commitment

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 following table shows the Company's rental commitment amounts for the next three fiscal years:

	2016	2017	2018
Lease commitment	**$ 193,461**	$ 193,461	$ 80,609

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 and policies are set out in Notes 2 and 3 of the audited annual financial statements for the year ended December 31, 2015 and have been consistently followed in the preparation of the 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.

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.

Future Accounting Pronouncements

The IASB or IFRIC have issued pronouncements effective for accounting periods beginning on or after January 1, 2016. Only those which may significantly impact the Company are discussed below:

a) IFRS 15 *Revenue from Contracts with Customers* provides a single, principles based five-step model to be applied to all contracts with customers and two approaches to recognizing revenue: at a point in time or over time. The model features a contract-based five-step analysis of transaction to determine whether, how much and when revenue is recognized. New judgmental thresholds have been introduced, which may affect the amount and/or timing of revenue recognized. New disclosures about revenue are also introduced. The new standard is effective for annual periods beginning on or after January 1, 2018.

b) IFRS 9 *Financial Instruments (2014)* is a finalized version of IFRS 9, which contains accounting requirements for financial instruments, replacing IAS 39 *Financial Instruments: Recognition and Measurement*. The standard contains requirements in the following areas:

- Classification and measurement. Financial assets are classified by reference to the business model within which they are held and their contractual cash flow characteristics. The 2014 version of IFRS 9 introduces a "fair value through other comprehensive income" category for certain debt instruments. Financial liabilities are classified in a similar manner to under IAS 39; however, there are differences in the requirements applying to the measurement of an entity's own credit risk.
- Impairment. The 2014 version of IFRS 9 introduces an "expected credit loss" model for the measurement of the impairment of financial assets, so it is no longer necessary for a credit event to have occurred before a credit loss is recognized.
- Hedge accounting. Introduces a new hedge accounting model that is designed to be more closely aligned with how entities undertake risk management activities when hedging financial and non-financial risk exposures.

  The mandatory effective date for IFRS 9 is for annual periods beginning on or after January 1, 2018 and must be applied retrospectively with some exemptions.

c) IFRS 16 *Leases* requires the recognition of most leases on the balance and effectively removes the classification of leases as either finance or operating leases and treats all leases as finance leases for lessees with exemptions for short-term leases where the lease term is twelve months or less and for leases of low value items. IFRS 16 accounting treatment for lessors is unchanged, which provides the choice of classifying a lease as either a finance or operating lease. The new standard is effective for annual periods beginning on or before January 1, 2019.

The Company has not fully completed its evaluation of the effect of adopting these standards on its financial statements. The Company will adopt IFRS 15, IFRS 9 and IFRS 16 when required by the IASB.

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, 2015, the Company's financial instruments include accounts receivable, reclamation deposits, bank indebtedness, accounts payable and accrued liabilities.

The fair values of accounts receivable, reclamation deposits, bank indebtedness, accounts payable and accrued liabilities approximate their carrying values due to the short-term maturity of these financial instruments.

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 venture partners and oil and natural gas marketers and its reclamation deposits. Any risk associated with accounts receivable is minimized substantially by the financial strength of the Company's joint venture partners, operators and marketers. The credit risk associated with reclamation deposits is mitigated by ensuring these financial assets are placed with major financial institutions with strong investment-grade ratings by a primary ratings agency. The Company does not anticipate any default. There are no balances past due 90 days or impaired.

The maximum exposure to credit risk is as follows:

	As at	
	December 31, 2015	December 31, 2014
Accounts receivable		
Trade receivables	**$ 385,432**	$ 1,208,897
Receivables from joint venture	**153,897**	95,355
Reclamation deposits	**115,535**	105,535
Total	**$ 654,864**	$ 1,409,787

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

Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they come due. The Company manages liquidity risk by anticipating operating, investing and financing activities and ensuring that it will have sufficient liquidity to meet its liabilities when they become due, under both normal and stressed conditions, without incurring unacceptable losses or risking damage to the Company. The Company prepares expenditure budgets on a quarterly and annual basis which are regularly monitored and updated when necessary in order to review debt forecasts and working capital requirements.

At December 31, 2015, the Company had net debt of $11,446,110 (December 31, 2014 - $11,644,609), which includes bank indebtedness of $10,828,040 (December 31, 2014 - $7,184,147). The Company funds its operations through production revenue and a demand operating credit facility. All of the Company's financial liabilities have contractual maturities of less than 90 days.

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 credit facilities are subject to variable interest rates. A one percent change in interest rates would not have a material effect on net loss and comprehensive 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; however, 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 did not have any foreign exchange rate swaps or related contracts in place as at the date of this document.

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 ability to raise capital. The Company has not entered into any commodity hedge contracts as at the date of this document.

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 and Additional IFRS Measures

This document contains the terms "funds flow from operations" which is an additional IFRS measure presented in the financial statements. This document also contains the terms "operating netback" and "net debt" which are not recognized measures under IFRS and may not be comparable to similar measures presented by other companies.

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

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

	Three Months Ended December 31		**Year Ended December 31**	
	2015	2014	**2015**	2014
Cash provided by (used in) operating activities	**$ (171,749)**	$ 1,645,958	**$ 2,993,272**	$ 6,850,566
Decommissioning obligation expenditures	**-**	-	**2,591**	-
Change in non-cash working capital	**68,218**	(212,564)	**192,622**	13,353
Funds flow from (used in) operations	**$ (103,531)**	$ 1,433,394	**$ 3,188,486**	$ 6,863,919
Per share, basic and diluted	**$ (0.00)**	$ 0.02	**$ 0.04**	$ 0.10

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

c) Net debt 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:

	December 31, 2015	December 31, 2014
Current assets	**$ 686,869**	$ 1,437,181
Current liabilities[(1)]	**(1,304,939)**	(5,897,643)
Bank indebtedness	**(10,828,040)**	(7,184,147)
Net debt	**$ (11,446,110)**	$ (11,644,609)

Note:
(1) Excluding bank indebtedness and flow-through premium liability.

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. In addition, given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

Forward-Looking Statements

In the interest of providing Hemisphere's shareholders and potential investors with information regarding the Company, including management's assessment of the future plans and operations of Hemisphere, certain statements contained in this MD&A constitute forward-looking statements or information (collectively "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements are typically identified by words such as "anticipate", "continue", "estimate", "expect", "forecast", "may", "will", "project", "could", "plan", "intend", "should", "believe", "outlook", "potential", "target" and similar words suggesting future events or future performance. In particular, but without limiting the foregoing, this document may contain forward-looking statements pertaining to the following: volumes and estimated value of Hemisphere's oil and natural gas reserves; the life of Hemisphere's reserves; the volume and product mix of Hemisphere's oil and natural gas production; future oil and natural gas prices; future operational activities; and future results from operations and operating metrics, including any future production growth and net debt, management's plans to accelerate development in the event of a recovery in commodity prices, and management's plans to continue with 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) 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, 2015 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 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.

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, 2016

(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 statement of financial position as at December 31, 2015, the statements of loss and comprehensive loss, changes in shareholders' equity and cash flows for the year 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 audit. We conducted our audit 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 audit 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, 2015, and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards.

Comparative Information
The financial statements of Hemisphere Energy Corporation as at and for the year ended December 31, 2014 were audited by another auditor who expressed an unmodified opinion on those financial statements on April 21, 2015.

KPMG LLP

Chartered Professional Accountants
April 26, 2016
Calgary, Canada

STATEMENTS OF FINANCIAL POSITION

(Expressed in Canadian dollars)

	Notes	**December 31, 2015**	December 31, 2014
Assets			
Current assets			
Accounts receivable	5(a)	**$ 539,329**	$ 1,304,252
Prepaid expenses		**147,540**	132,929
		686,869	1,437,181
Non-current assets			
Reclamation deposits	9	**115,535**	105,535
Exploration and evaluation assets	7	**3,100,937**	2,896,887
Property, plant and equipment	8	**36,907,703**	42,870,113
Deferred tax asset	17	**-**	1,641,916
Total assets		**$ 40,811,044**	$ 48,951,632
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities		**$ 1,304,939**	$ 5,897,643
Bank indebtedness	11	**10,828,040**	7,184,147
		12,132,979	13,081,790
Non-current liabilities			
Decommissioning obligations	9	**5,965,233**	5,177,607
		18,098,212	18,259,397
Shareholders' Equity			
Share capital	12	**52,083,070**	51,881,960
Contributed surplus	12(b)	**2,461,870**	2,513,122
Deficit		**(31,832,108)**	(23,702,847)
Total shareholders' equity		**22,712,832**	30,692,235
Total liabilities and shareholders' equity		**$ 40,811,044**	$ 48,951,632

Commitment (Note 14)
Subsequent events (Note 16)

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	Year Ended December 31, 2015	December 31, 2014
Oil and natural gas revenue		**$ 9,749,377**	$ 16,635,279
Royalties		**(774,798)**	(3,008,377)
Net oil and natural gas revenue		**8,974,579**	13,626,902
Expenses			
Production and operating		**3,639,483**	4,351,248
Exploration and evaluation	7	**64,596**	190,887
Depletion and depreciation	8	**5,120,705**	5,360,989
General and administrative		**1,699,514**	2,202,163
Share-based payments	12(b)	**181,580**	452,780
Impairment	8	**4,366,257**	2,702,925
		15,072,135	15,260,992
Results from operating activities		**(6,097,556)**	(1,634,090)
Finance expense	10	**(571,359)**	(276,347)
Gain on disposition		**-**	2,942
Loss before income taxes		**(6,668,915)**	(1,907,495)
Deferred tax (expense) / recovery	17	**(1,641,916)**	239,688
Net loss and comprehensive loss for the year		**$ (8,310,831)**	$ (1,667,807)
Loss per share			
Basic and diluted	12(d)	**$ (0.11)**	$ (0.02)

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, 2013		**61,307,498**	**$**	**42,127,674**	**$**	**2,574,789**	**$**	**204,479**	**$**	**(22,568,372)**	**$**	**22,338,570**
Common share issuance	12(a)	13,333,500		10,000,125		-		-		-		10,000,125
Share-based payments	12(b)	-		-		452,780		-		-		452,780
Share issuance costs, net of tax	12(a)	-		(680,408)		-		-		-		(680,408)
Exercise of stock options	12(a)	690,000		404,944		(184,094)		-		-		220,850
Expiry of stock options	12(b)	-		-		(1,159)		-		1,159		-
Exercise of warrants	12(a)	37,500		29,625		-		(1,500)		-		28,125
Expiry of warrants	12(c)	-		-		(329,194)		(202,979)		532,173		-
Net loss for the year		-		-		-		-		(1,667,807)		(1,667,807)
Balance, December 31, 2014		**75,368,498**	**$**	**51,881,960**	**$**	**2,513,122**	**$**	**-**	**$**	**(23,702,847)**	**$**	**30,692,235**
Balance, December 31, 2014		**75,368,498**	**$**	**51,881,960**	**$**	**2,513,122**	**$**	**-**	**$**	**(23,702,847)**	**$**	**30,692,235**
Share-based payments	12(b)	-		-		222,677		-		-		222,677
Exercise of stock options	12(b)	435,000		201,110		(92,359)		-		-		108,751
Expiry of stock options	12(b)	-		-		(181,570)		-		181,570		-
Net loss for the year		-		-		-		-		(8,310,831)		(8,310,831)
Balance, December 31, 2015		**75,803,498**	**$**	**52,083,070**	**$**	**2,461,870**	**$**	**-**	**$**	**(31,832,108)**	**$**	**22,712,832**

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

STATEMENTS OF CASH FLOWS
(Expressed in Canadian dollars)

	Year Ended December 31, 2015	December 31, 2014
Operating activities		
Net loss for the year	$ **(8,310,831)**	$ (1,667,807)
Items not affecting cash:		
Depletion and depreciation	**5,120,705**	5,360,989
Accretion	**124,263**	66,776
Exploration and evaluation expense	**64,596**	190,887
Gain on disposition	**-**	(2,942)
Impairment of property and equipment	**4,366,257**	2,702,925
Deferred tax expense	**1,641,916**	(239,688)
Share-based payments	**181,580**	452,780
Funds flow from operations	**3,188,486**	6,863,919
Decommissioning expenditures	**(2,591)**	-
Changes in non-cash working capital (Note 15)	**(192,622)**	(13,353)
Cash provided by operating activities	**2,993,272**	6,850,566
Investing activities		
Property, plant and equipment expenditures	**(2,611,074)**	(19,429,763)
Exploration and evaluation expenditures	**(475,073)**	(2,080,433)
Proceeds from disposition of property and equipment	**-**	50,000
Reclamation deposits	**(10,000)**	-
Changes in non-cash working capital (Note 15)	**(3,649,771)**	2,595,854
Cash used in investing activities	**(6,745,916)**	(18,864,341)
Financing activities		
Shares issued for cash	**-**	9,080,653
Shares issued for exercise of stock options and warrants	**108,751**	248,975
Increase in bank indebtedness	**3,643,893**	2,684,147
Cash provided by financing activities	**3,752,644**	12,013,775
Net change in cash	**-**	-
Cash, beginning of year	**-**	-
Cash, end of year	$ **-**	$ -

Supplemental cash flow information (Note 15)

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

NOTES TO THE FINANCIAL STATEMENTS

For the years ended December 31, 2015 and December 31, 2014
(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 financial statements are 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, 2016.

(b) Basis of presentation

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

(c) Functional and presentation currency

These annual 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 part 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 – estimates of reserves, future commodity prices, future costs, production profiles, discount rates, market value of land. Judgments are also required to assess when impairment indicators exist and impairment testing is required.
(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) Deferred tax – estimates of reversal of temporary differences, tax rates substantively enacted, and likelihood of assets being realized.
(vi) Determinations of cash generating units ("CGUs") – geographic location, commodity type, reservoir characteristics and lowest level of cash inflows.
(vii) Determining the technical feasibility and commercial viability of exploration and evaluation assets.
(viii) 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
(ix) Provisions - exercise of significant judgment and estimates of the outcome of future events.

3. Significant Accounting Policies

(a) Financial instruments

(i) Financial assets

The Company classifies its financial assets in the following categories: held-to-maturity, fair value through profit or loss ("FVTPL"), loans and receivables, and available-for-sale ("AFS"). The classification depends on the purpose for which the financial assets were acquired. Management determines the classification of financial assets at recognition.

Held-to-maturity

Held-to-maturity financial assets are recognized on a trade-date basis and are initially measured at fair value using the effective interest rate method. The Company has no assets classified as held-to-maturity.

Financial assets at fair value through profit or loss

Financial assets at FVTPL are initially recognized at fair value with changes in fair value recorded through profit or loss.

Loans and receivables

Loans and receivables are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market. They are classified as current assets or non-current assets based on their maturity date. Loans and receivables are carried at amortized cost less any impairment.

Available-for-sale financial assets

AFS financial assets are non-derivatives that are either designated as available-for-sale or not classified in any of the other financial asset categories. Changes in the fair value of AFS financial assets are recognized as other comprehensive income and classified as a component of equity.

Management assesses the carrying value of any AFS financial assets at least annually and any impairment charges are also recognized in profit or loss. When financial assets classified as AFS are sold, the accumulated fair value adjustments recognized in other comprehensive income are included in profit or loss.

(ii) Financial liabilities

Borrowings and other financial liabilities

Borrowings and other financial liabilities are non-derivatives and are recognized initially at fair value, net of transaction costs incurred, and are subsequently stated at amortized cost. Any difference between the amounts originally received, net of transaction costs, and the redemption value is recognized in profit or loss over the period to maturity using the effective interest method.

Borrowings and other financial liabilities are classified as current or non-current based on their maturity date. Financial liabilities are comprised of accounts payable and accrued liabilities and bank indebtedness.

(iii) Share capital

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

(iv) 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.

Additional disclosure on the measurement of financial instruments is provided in Note 4.

(b) 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, including operating and maintenance costs, transportation and royalty expenses, are recognized during the same period in which the related revenue is earned and reported.

(c) Jointly controlled assets

Some of the Company's petroleum and natural gas activities involve jointly controlled 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.

(d) 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 NI 51-101. 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 less the estimated net realizable value of production equipment and facilities after the Proved and Probable reserves are fully produced.

Proved 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 producible 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 an 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 an observable market 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.

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.

(e) 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.

(f) Share-based payments

The Company has a stock option plan that is described in Note 11(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.

(g) Equity units

The Company uses the residual value method with respect to the measurement of equity units. The proceeds from the issue of units is allocated between common shares and share purchase warrants on a residual value basis, wherein the fair value of the common shares is based on the market close on the date the units are issued; the balance, if any, is allocated to the attached warrants. Share issue costs are netted against share proceeds.

(h) 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 and is subsequently reversed as the Company incurs qualifying the designated Canadian exploration or development expenses.

In circumstances where the Company has issued flow-through shares by way of a unit offering, the proceeds are allocated first to common shares based on the market close at the time the units are priced, and any residual value is allocated next to the warrants reserve based on the fair value of the warrant component using the Black-Scholes option pricing model on grant date. Any remaining residual value is then recognized as a liability for the premium on the flow-through shares.

(i) 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.

(j) 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.

(k) Future accounting pronouncements

The IASB or IFRIC have issued pronouncements effective for accounting periods beginning on or after January 1, 2016. Only those which may significantly impact the Company are discussed below:

a) IFRS 15 *Revenue from Contracts with Customers* provides a single, principles based five-step model to be applied to all contracts with customers and two approaches to recognizing revenue: at a point in time or over time. The model features a contract-based five-step analysis of transaction to determine whether, how much and when revenue is recognized. New judgmental thresholds have been introduced, which may affect the amount and/or timing of revenue recognized. New disclosures about revenue are also introduced. The new standard is effective for annual periods beginning on or after January 1, 2018.

b) IFRS 9 *Financial Instruments (2014)* is a finalized version of IFRS 9, which contains accounting requirements for financial instruments, replacing IAS 39 *Financial Instruments: Recognition and Measurement*. The standard contains requirements in the following areas:

- Classification and measurement. Financial assets are classified by reference to the business model within which they are held and their contractual cash flow characteristics. The 2014 version of IFRS 9 introduces a "fair value through other comprehensive income" category for certain debt instruments. Financial liabilities are classified in a similar manner to under IAS 39; however, there are differences in the requirements applying to the measurement of an entity's own credit risk.
- Impairment. The 2014 version of IFRS 9 introduces an "expected credit loss" model for the measurement of the impairment of financial assets, so it is no longer necessary for a credit event to have occurred before a credit loss is recognized.
- Hedge accounting. Introduces a new hedge accounting model that is designed to be more closely aligned with how entities undertake risk management activities when hedging financial and non-financial risk exposures.

The mandatory effective date for IFRS 9 is for annual periods beginning on or after January 1, 2018 and must be applied retrospectively with some exemptions.

c) IFRS 16 *Leases* requires the recognition of most leases on the balance and effectively removes the classification of leases as either finance or operating leases and treats all leases as finance leases for lessees with exemptions for short-term leases where the lease term is twelve months or less and for leases of low value items. IFRS 16 accounting treatment for lessors is unchanged, which provides the choice of classifying a lease as either a finance or operating lease. The new standard is effective for annual periods beginning on or before January 1, 2019.

The Company has not fully completed its evaluation of the effect of adopting these standards on its financial statements. The Company will adopt IFRS 15, IFRS 9 and IFRS 16 when required by the IASB.

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, 2015, 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.

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, 2015	December 31, 2014
Accounts receivable		
Trade receivables	**$ 385,432**	$ 1,208,897
Receivable from joint operators	**153,897**	95,355
Reclamation deposits	**115,535**	105,535
	$ 654,864	$ 1,409,787

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, 2015, the Company had net debt of $11,446,110 (December 31, 2014 - $11,644,609), which includes bank indebtedness of $10,828,040 (December 31, 2014 - $7,184,147). The Company funds its operations through production revenue and a demand operating credit facility (Note 11). All of the Company's financial liabilities have contractual maturities of less than 90 days.

(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 credit facilities are subject to variable interest rates. A one percent change in interest rates would have a $110,000 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; however, 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. The Company did not have any foreign exchange rate swaps or related contracts in place as at the date of this document.

(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 ability to raise capital. The Company has not entered into any commodity hedge contracts as at the date of this document.

(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.

Capital Management

The Company manages its capital with the following objectives:

(a) To ensure sufficient financial flexibility to achieve the Company's ongoing business objectives including the replacement of production, funding of future growth opportunities and pursuit of accretive acquisitions; and

(b) To maximize shareholder return through enhancing the Company's share value.

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

6. Exploration and Evaluation Assets

Exploration and evaluation assets consist of the Company's exploration projects, which are pending the determination of Proved and Probable reserves. A transfer from exploration and evaluation assets to property and equipment is made when reserves are assigned or the exploration project has been completed. For the year ended December 31, 2015, the Company; transferred $206,427 (December 31, 2014 - $993,271) to property and equipment, capitalized general and administrative expenses of $241,457 (December 31, 2014 - $nil) to exploration and evaluation assets, and recognized exploration and evaluation expense of $64,596 (December 31, 2014 - $190,887) which was a result of several land expiries in the year.

Cost		
Balance, December 31, 2013	$	2,000,613
Additions		2,080,432
Exploration and evaluation expense		(190,887)
Transfer to property and equipment		(993,271)
Balance, December 31, 2014	$	2,896,887
Additions		475,073
Exploration and evaluation expense		(64,596)
Transfer to property and equipment		(206,427)
Balance, December 31, 2015	**$**	**3,100,937**

7. Property, Plant and Equipment

		Petroleum and Natural Gas		Other Equipment		Total
Cost						
Balance, December 31, 2013	$	39,010,699	$	67,522	$	39,078,221
Additions		19,382,791		46,970		19,429,761
Increase in decommissioning obligations		3,099,549		-		3,099,549
Transfer from exploration and evaluation assets		993,271		-		993,271
Balance, December 31, 2014	$	62,486,310	$	114,492	$	62,600,802
Additions		2,611,074		-		2,611,074
Increase in decommissioning obligations		665,954		-		665,954
Capitalized share-based payments		41,097		-		41,097
Transfer from exploration and evaluation assets		206,427		-		206,427
Balance, December 31, 2015	**$**	**66,010,862**	**$**	**114,492**	**$**	**66,125,354**
Accumulated Depletion, Depreciation, Amortization and Impairment						
Balance, December 31, 2013	$	11,612,271	$	54,504	$	11,666,775
Depletion and depreciation for the year		5,353,585		7,404		5,360,989
Impairment		2,702,925		-		2,702,925
Balance, December 31, 2014	$	19,668,782	$	61,908	$	19,730,689
Depletion and depreciation for the year		5,107,250		13,455		5,120,705
Impairment		4,366,257		-		4,366,257
Balance, December 31, 2015	**$**	**29,142,289**	**$**	**75,362**	**$**	**29,217,651**
Net Book Value						
December 31, 2014	$	42,817,529	$	52,584	$	42,870,113
December 31, 2015	**$**	**36,868,573**	**$**	**39,130**	**$**	**36,907,703**

The Company's additions for property and equipment included capitalized general and administrative expenses of $122,296 and $472,530 for the years ended December 31, 2015 and 2014, respectively.

The calculation for depletion at December 31, 2015 includes estimated future development costs of $18,263,600 (December 31, 2014 - $23,083,300) associated with the development of the Company's Proved plus Probable reserves.

(a) Property acquisitions for the year ended December 31, 2015:

On May 19, 2015, the Company completed a strategic tuck-in acquisition of the remaining 15% working interest in 1.75 sections (1,120 acres) of land in Atlee Buffalo for a purchase price of $250,000 and $21,000 additional capitalized costs. The Company now has 100% working interest in this land.

(b) Property acquisitions for the year ended December 31, 2014:

On February 28, 2014, the Company closed an acquisition of a non-producing property for proceeds of $100,000 which included 1.75 sections (1,120 acres) in the surrounding Jenner area.

On May 29, 2014, the Company closed an acquisition in the Atlee Buffalo property for proceeds of $510,000 which included an 85% working interest in 1.75 sections (1,120 acres) of land adjacent to the Company's existing Atlee property.

During the year ended December 31, 2014, the Company also recorded an additional $24,739 for final statement of adjustments pertaining to an acquisition closed on November 14, 2013.

At December 31, 2015, the Company performed an assessment of potential impairment indicators, and management determined that with the prolonged reduction in commodity prices and the Company's deferred capital development plans that an impairment test on its petroleum and natural gas assets was required. The Company performed an impairment test on its petroleum and natural gas assets and it was determined that the carrying amount of three CGUs exceeded their recoverable amount. Accordingly, the Company recognized an impairment charge of $4,366,257 for the year ended December 31, 2015 (December 31, 2014 - $2,702,925).

The recoverable amounts were determined with value in use using a discounted cash flow method. Key assumptions in the determination of cash flows from reserves include crude oil and natural gas prices and discount rates specific to the underlying composition of assets residing in each CGU. The pre-tax discount rates ranged from 10% to 15% depending on the nature of the reserves.

	As at December 31, 2015	
CGU	**Impairment**	**Recoverable Value**
Jenner, Alberta	$ 4,336,170	$ 16,802,308
Wainwright, Alberta	23,477	-
Trutch, British Columbia	6,610	-

The following table show the future commodity price estimates used by the Company's independent reserves evaluator at December 31, 2015 and 2014:

2015	2016	2017	2018	2019	2020	2021	2022	2023	Thereafter
WTI (US$/bbl)	45.00	53.60	62.40	69.00	73.10	77.30	81.60	86.20	+2%/yr
WCS (C$/bbl)	46.40	54.40	59.70	66.30	68.20	72.30	76.50	80.90	+2%/yr
AECO(Cdn$/MMbtu)	2.50	2.95	3.40	3.70	3.90	4.15	4.35	4.60	+2%/yr

2014	2015	2016	2017	2018	2019	2020	2021	2022	Thereafter
WTI (US$/bbl)	65.00	75.00	80.00	84.90	89.30	93.80	95.70	97.60	+2%/yr
WCS (C$/bbl)	57.60	69.90	74.70	79.70	83.70	87.90	89.80	91.60	+2%/yr
AECO(Cdn$/MMbtu)	3.50	4.00	4.25	4.50	4.70	5.00	5.30	5.50	+2%/yr

8. Decommissioning Obligations

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

The Company estimates the total undiscounted and inflated amount of cash flows required to settle its decommissioning obligations as at December 31, 2015 is $10,104,158 (December 31, 2014 - $8,345,397). These payments are expected to be made over the next 38 years with the majority of costs to be incurred between 2025 and 2047. The discount factor, being the risk-free rate related to the liability, is 2.46% (December 31, 2014 – 2.40%). Inflation of 2.18% (December 31, 2014 - 1.70%) has also been factored into the calculation. The Company also has $115,535 (December 31, 2014 - $105,535) in various reclamation bonds for its properties held by Alberta Energy Regulator and British Columbia Ministry of Energy, Mines and Petroleum Resources.

		December 31, 2015		December 31, 2014
Decommissioning obligations, beginning of year	$	**5,177,607**	$	2,011,282
Increase in estimated future obligations		**32,812**		1,799,601
Change in estimate		**633,142**		1,299,948
Decommissioning obligation expenditures		**(2,591)**		-
Accretion expense		**124,263**		66,776
Decommissioning obligations, end of year	$	**5,965,233**	$	5,177,607

9. Finance Income and Expenses

		Year Ended December 31, 2015		Year Ended December 31, 2014
Finance expense				
Interest expense	$	**447,096**	$	197,682
Part XII.6 tax		**-**		11,889
Accretion of provision		**124,263**		66,776
Net finance expenses	$	**571,359**	$	276,347

10. Bank Indebtedness

The Company had a demand operating credit facility in the amount of $15.0 million with Alberta Treasury Branches ("ATB") which was renewed in July 2015. Funds available under the credit facility are restricted to $14.0 million and access to the remaining $1.0 million is based on additional approval from ATB.

The facility is secured by a general security agreement and a floating charge on all lands of the Company. The facility bears interest at the bank's prime rate plus 1.75%, as well as a standby charge for any undrawn funds. As the available lending limits of the facilities are based on the bank's interpretation of the Company's reserves and future commodity prices, there can be no assurance as to the amount of available facilities that will be determined at each scheduled review. The Company is currently conducting its review with ATB, which it expects to have completed in the May 2016.

Pursuant to the terms of the credit facility, the Company has provided a financial covenant that at all times its working capital ratio shall not be less than 1.0. The working capital ratio is defined under the terms of the credit facilities as current assets including the undrawn portion of the revolving operating demand line credit facility ($14.0 million), to current liabilities, excluding any current bank indebtedness.

At December 31, 2015, the Company has drawn a total of $10,828,040 from the credit facility (December 31, 2014 - $7,184,147) and had a working capital ratio of 3.0, which is in compliance with the above financial covenant.

11. Capital Stock

(a) Authorized

Unlimited number of common shares without par value.

Issued and outstanding

As at December 31, 2015, the Company had 75,803,498 shares issued and outstanding.

During the year ended December 31, 2015, the Company issued 435,000 common shares for the exercise of stock options at $0.25 each.

The following occurred during the year ended December 31, 2014:

(i) On May 14, 2014, the Company closed a bought-deal equity financing consisting of 13,333,500 common shares at a price of $0.75 per common share for aggregate gross proceeds of $10,000,125. In conjunction with the closing of the bought-deal equity financing, the Company paid $919,471 in share issuance costs (net of tax $680,408), which include $700,009 in finders' fees.

(ii) The Company issued 690,000 common shares for the exercise of incentive stock options at various exercise prices for gross proceeds of $220,850. Additionally, the Company issued 37,500 common shares for the exercise of share purchase warrants at a price of $0.75 each for gross proceeds of $28,125.

(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.

During the year ended December 31, 2015, the Company received gross proceeds of $108,750 for the exercise of 435,000 stock options at $0.25 each.

Details of the Company's stock options as at December 31, 2015 and 2014 are as follows:

Exercise Price	Expiry Date	Balance Outstanding December 31, 2014	Changes in the Year: Granted	Changes in the Year: Exercised	Changes in the Year: Expired	Balance Outstanding December 31, 2015	Balance Exercisable December 31, 2015
$0.25	8-Mar-15	435,000	-	(435,000)	-	-	-
$0.26	30-Sep-15	490,000	-	-	(490,000)	-	-
$0.30	23-Dec-15	375,000	-	-	(375,000)	-	-
$0.30	27-Jan-16	200,000	-	-	-	200,000	200,000
$0.38	9-Feb-16	50,000	-	-	-	50,000	50,000
$0.40	26-May-16	475,000	-	-	-	475,000	475,000
$0.48	5-Jul-16	50,000	-	-	-	50,000	50,000
$0.70	8-Feb-17	1,500,000	-	-	-	1,500,000	1,500,000
$0.65	24-Apr-17	75,000	-	-	-	75,000	75,000
$0.61	5-Jul-17	425,000	-	-	-	425,000	425,000
$0.50	8-Mar-18	250,000	-	-	-	250,000	250,000
$0.55	6-Jan-19	660,000	-	-	-	660,000	660,000
$0.65	29-Sep-19	785,000	-	-	-	785,000	785,000
$0.61	7-Oct-19	200,000	-	-	-	200,000	200,000
$0.24	29-Jan-20	-	1,225,000	-	-	1,225,000	1,218,750
$0.39	1-Mar-20	-	100,000	-	-	100,000	100,000
		5,970,000	1,325,000	(435,000)	(865,000)	5,995,000	5,988,750
Weighted-average exercise price		$0.52	$0.25	$0.25	$0.28	$0.52	$0.52

Exercise Price	Expiry Date	Balance Outstanding December 31, 2013	Changes in the Year: Granted	Changes in the Year: Exercised	Changes in the Year: Cancelled	Balance Outstanding December 31, 2014	Balance Exercisable December 31, 2014
$0.27	28-Sep-14	445,000	-	(440,000)	(5,000)	-	-
$0.25	8-Mar-15	485,000	-	(50,000)	-	435,000	435,000
$0.26	30-Sep-15	520,000	-	(30,000)	-	490,000	490,000
$0.30	23-Dec-15	425,000	-	(50,000)	-	375,000	375,000
$0.30	27-Jan-16	200,000	-	-	-	200,000	200,000
$0.38	9-Feb-16	50,000	-	-	-	50,000	50,000
$0.40	26-May-16	520,000	-	(45,000)	-	475,000	475,000
$0.48	5-Jul-16	50,000	-	-	-	50,000	50,000
$0.70	8-Feb-17	1,550,000	-	(50,000)	-	1,500,000	1,500,000
$0.65	24-Apr-17	75,000	-	-	-	75,000	75,000
$0.61	5-Jul-17	425,000	-	-	-	425,000	425,000
$0.50	8-Mar-18	250,000	-	-	-	250,000	250,000
$0.55	6-Jan-19	685,000	-	(25,000)	-	660,000	660,000
$0.65	29-Sep-19	-	785,000	-	-	785,000	785,000
$0.61	7-Oct-19	-	200,000	-	-	200,000	200,000
		5,680,000	985,000	(690,000)	(5,000)	5,970,000	5,970,000
Weighted-average exercise price		$0.48	$0.64	$0.32	$0.27	$0.52	$0.52

For the year ended December 31, 2015, the Company recognized $181,580 (year ended December 31, 2014 - $452,780) in share-based payment expense from the granting of 1,325,000 (year ended December 31, 2014 - 985,000) options vesting immediately to directors, officers, consultants and employees of the Company. The fair value was determined using the Black-Scholes option pricing model with the following weighted average assumptions:

	December 31, 2015	December 31, 2014
Expected life (years)	**5.00**	5.00
Interest rate	**0.79%**	1.59%
Volatility	**91.71%**	91.99%
Dividend yield	**0.00%**	0.00%
Fair value at grant date	**$0.17**	$0.46

The weighted-average exercise price for stock options granted during the year ended December 31, 2015 was $0.25 (year ended December 31, 2014 - $0.64). The forfeiture rate has been estimated at 5% (December 31, 2014 - 0%).

Throughout the year ended December 31, 2015, the Company removed $92,359 (year ended December 31, 2014 - $184,094) from contributed surplus and recorded a corresponding amount in share capital for exercised stock options.

Throughout the year ended December 31, 2015, the Company removed $181,570 (year ended December 31, 2014 - $1,159) from contributed surplus and recorded a corresponding recovery in deficit for expired stock options.

(c) Share purchase warrants

The Company had no share purchase warrants as at December 31, 2015.

Details of the Company's share purchase warrants as at December 31, 2014 are as follows:

			Change in the Year			
Exercise Price	Expiry Date	Balance Outstanding & Exercisable December 31, 2013	Issued	Exercised	Expired	Balance Outstanding & Exercisable December 31, 2014
$0.90	25-Jan-14	43,450	-	-	(43,450)	-
$0.90	25-Jan-14	700	-	-	(700)	-
$0.95	27-Jan-14	6,161,578	-	-	(6,161,578)	-
$0.95	27-Jan-14	86,256	-	-	(86,256)	-
$0.70	27-Jan-14	862,620	-	-	(862,620)	-
$0.75	9-Dec-14	2,091,275	-	(37,500)	(2,053,775)	-
		9,245,879	-	(37,500)	(9,208,379)	-
Weighted-average exercise price		$0.88	-	$0.75	$0.88	-

Throughout the year ended December 31, 2015, the Company removed $nil (year ended December 31, 2014 - $1,500) from the warrant reserve and recorded a corresponding recovery in share capital for exercised warrants.

Throughout the year ended December 31, 2015, the Company removed $nil (year ended December 31, 2014 - $202,979) from the warrant reserve and recorded a corresponding recovery in deficit for expired warrants.

(d) Loss per share

		Year Ended December 31, 2015		Year Ended December 31, 2014
Loss for the period	**$**	**(8,310,831)**	$	(1,667,807)
Weighted-average number of common shares outstanding, basic		**75,758,868**		70,075,411
Dilutive stock options and share purchase warrants		**-**		-
Weighted-average number of common shares outstanding, diluted		**75,758,868**		70,075,411
Loss per share, basic and diluted	**$**	**(0.11)**	$	(0.02)

For the years ended December 31, 2015 and 2014, the Company incurred a loss; therefore, dilutive stock options and share purchase warrants were nil.

12. Related Party Transactions

During the year ended December 31, 2015, the Company paid fees of $40,000 to a director of the Company. These fees were charged for services provided by the Chairman of the Company's Board of Directors.

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

	Year Ended December 31			
		2015		2014
Short-term benefits	**$**	**820,000**	$	986,666
Share-based payments		**135,660**		377,743

13. Commitment

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 following table shows the Company's rental commitment amounts for the next three fiscal years:

		2016		2017		2018
Rental commitment	**$**	**193,461**	$	193,461	$	80,609

14. Supplemental Cash Flow Information

	Year Ended December 31, 2015	December 31, 2014
Provided by (used in):		
Accounts receivable	**$ 764,923**	$ (261,845)
Prepaid expenses	**(14,611)**	(29,757)
Accounts payable and accrued liabilities	**(4,592,704)**	2,874,103
Total changes in non-cash working capital	**$ (3,842,392)**	$ 2,582,501
Provided by (used in):		
Operating activities	**$ (192,622)**	$ (13,353)
Investing activities	**(3,649,771)**	2,595,854
Total changes in non-cash working capital	**$ (3,842,392)**	$ 2,582,501

Interest paid on the Company's bank loan during the year ended December 31, 2015 was $447,096 (year ended December 31, 2014 - $197,682).

15. Subsequent Events

Subsequent to December 31, 2015, 200,000 incentive stock options expired at a price of $0.30 and an additional 50,000 incentive stock options expired at a price of $0.38.

On February 12, 2016, the Company cancelled a total of 2,395,000 incentive stock options granted to certain officers, directors, employees and consultants who voluntarily returned these options to the Company. The cancelled options were granted from April 2012 to October 2014 and were exercisable at prices ranging from $0.50 to $0.65 for a period of five years from the date of grant.

In February 2016, the Company granted incentive stock options to officers, directors, employees and consultants of the Company entitling them to purchase up to a total of 1,985,000 common shares at an exercise price of $0.08 each.

In April 2016, 100,000 incentive stock options were exercised at a price of $0.08 per share for gross proceeds of $8,000 and 225,000 incentive stock options were cancelled at exercise prices ranging from $0.24 to $0.70.

16. Income Taxes

The reconciliation of income tax computed at the statutory tax rate of 26.00% (year ended December 31, 2014 – 26.00%) to income tax expense is:

	Year Ended December 31, 2015	December 31, 2014
Income (loss) before income taxes	**$ (6,668,915)**	$ (1,907,495)
Statutory income tax rate	**26.00%**	26.00%
Expected income tax expense (recovery)	**(1,733,918)**	(495,949)
Non-deductible items	**47,884**	117,722
Flow-through share premium	**-**	150,760
Temporary differences of property and equipment and evaluation and exploration assets	**-**	(12,222)
Effect of change in tax rate	**(76,080)**	-
Unused tax losses and tax offsets not recognized	**3,404,026**	-
Deferred tax expense (recovery)	**$ 1,641,911**	$ (239,688)

Effective July 1, 2015 the Alberta corporate income tax rate increased from 10% to 12%. This change in rate has resulted in an increase of deferred tax assets not recognized of $76,080 (December 31, 2014 - $nil)

The tax affected items that give rise to significant portions of the deferred tax asset at December 31, 2015 and 2014 are presented below:

	December 31, 2015	December 31, 2014
Deferred tax assets		
Non-capital losses	**$ 242,397**	$ 1,708,702
Share issue costs	**212,017**	341,076
Decommissioning obligations	**1,586,155**	1,350,465
	2,040,569	3,400,243
Deferred income tax liability		
Property and equipment	**(2,040,569)**	1,758,327
	$ -	$ 1,641,916

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, 2015	December 31, 2014
Net-capital losses	**$ 95,333**	$ 95,333
Non-capital losses	**12,820,696**	-
	$ 12,916,029	$ 95,333

As at December 31, 2015, the Company has non-capital losses of approximately $14 million 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	7,162,964
	$ 13,734,893

Hemisphere energy corporation

OFFICERS

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

Ian Duncan, P.Eng.
Chief Operating Officer

Dorlyn Evancic, CPA, CGA
Chief Financial 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, CPA, CA (Hon)(1)(2)(3)

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

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