

MANAGEMENT'S DISCUSSION AND ANALYSIS

Dated as at August 25, 2016

The following Management's Discussion and Analysis ("MD&A") is a review of the operations and current financial position for the three and six months ended June 30, 2016 for Hemisphere Energy Corporation ("Hemisphere" or the "Company") and should be read in conjunction with the unaudited interim condensed financial statements and related notes for the three and six months ended June 30, 2016, and the audited annual financial statements and related notes for the year ended December 31, 2015. These documents and additional information relating to the Company, including the Company's Annual Information Form, are available on SEDAR at www.sedar.com or the Company's website at www.hemisphereenergy.ca.

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

This MD&A contains non-IFRS measures and forward-looking statements. Readers are cautioned that this document should be read in conjunction with Hemisphere's disclosure under "Non-IFRS 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 26,290 net acres and has continued to build a land position in the Jenner area through Crown land sales and strategic acquisitions. The property is accessible year-round and is located east of Brooks in southeastern Alberta.

Atlee Buffalo, Alberta

The Company operates 100% of its wells in the Atlee Buffalo area. The property is accessible year-round and is located 30 kilometres east of the Company's Jenner property in southeastern Alberta. Hemisphere has a 100% working interest in 5,432 net acres and has been building a land position in Atlee Buffalo through Crown land sales and strategic acquisitions.

Operating Results

The Company generated funds flow from operations of \$159,894 (\$0.00/share) during the second quarter of 2016 as compared to \$1,320,981 (\$0.02/share) during the second quarter of 2015. For the six months ended June 2016, the Company generated negative funds flow from operations of \$87,620 (\$0.00/share) versus \$2,577,514 (\$0.03/share) from the comparable period in 2015. These changes in funds flow from operations are the result of the decline in commodity prices which began in the fourth quarter of 2014 and persisted through the first half of 2016, as well as a decrease in production (see Production section).

For the second quarter of 2016, the Company reported a net loss of \$580,725 (\$0.01/share) compared to a net loss of \$575,484 (\$0.01/share) for the second quarter of 2015. The Company reported a net loss of \$1,647,281 (\$0.02/share) for the six months ended June 30, 2016 as compared to a net loss of \$1,221,830 (\$0.02/share) for the same period in 2015.

Production

By product:	Three Months Ended June 30		Six Months Ended June 30	
	2016	2015	2016	2015
Oil (bbl/d)	407	655	408	743
Natural gas (Mcf/d)	499	1,149	540	1,055
NGL (bbl/d)	2	3	2	3
Total (boe/d)	492	849	500	922
Oil and NGL weighting	83%	77%	82%	81%

In the second quarter of 2016, the Company's average daily production decreased to 492 boe/d (83% oil and NGL) which represents a decrease of 42% over the second quarter of 2015. For the six months ended June 30, 2016, the Company's average daily production decreased by 46% over the comparable period in 2015. This decrease in production is attributed to the conversion of three producing wells into water injectors since the third quarter of 2015, increased down time as a result of delayed service work on wells to preserve capital during an extremely low commodity price environment, lower natural gas production by almost 100 boe/d since 2015 associated with the successful implementation of three waterflood pilots in the Atlee Buffalo Upper Mannville F pool, and overall declines in well production.

Average Benchmark and Realized Prices

	Three Months Ended June 30			Six Months Ended June 30		
	2016	2015		2016	2015	
Benchmark prices						
WTI (\$US/bbl) ⁽¹⁾	\$	45.59	\$	57.94	\$	39.52
Exchange rate (1 \$US/\$C)		1.2882		1.2289		1.3289
WTI (\$C/bbl)		58.73		71.21		52.52
WCS (\$C/bbl) ⁽²⁾		41.61		57.05		33.95
AECO natural gas (\$/Mcf) ⁽³⁾		1.42		2.62		1.62
Average realized prices						
Crude oil (\$/bbl)		37.59		50.49		29.97
Natural gas (\$/Mcf)		1.13		2.57		1.52
NGL (\$/bbl)		26.73		22.56		23.16
Combined (\$/boe)	\$	32.34	\$	42.49	\$	26.19
						37.24

Notes:

(1) Represents price of West Texas Intermediate Oil.

(2) Represents price of Western Canadian Select.

(3) Represents the Alberta 30 day spot AECO price.

The Company's oil and natural gas sales may vary over periods as a result of changes in commodity prices and/or production volumes. The West Texas Intermediate pricing ("WTI") at Cushing, Oklahoma is the benchmark reference price for North American crude oil prices. Canadian oil prices, including Hemisphere's crude oil, are based on the WTI price and adjusted for transportation, quality and the currency conversion rates from United States dollar ("USD") to Canadian dollar.

The Company's combined average realized price decreased by 24% from \$42.49/boe during the second quarter of 2015 to \$32.34/boe during the second quarter of 2016. For the six months ended June 30, 2016, the Company's combined average realized price decreased by 30% to \$26.19/boe from the same period in 2015. These decreases are primarily the result of the decline in WTI with wider differentials offset by more favourable exchange rates in the first and second quarters of 2016. The result of the decline in WTI is also reflected in the decrease of the Company's average realized oil prices for the three and six months ended June 30, 2016 to \$37.59/bbl and \$29.97/bbl, respectively, from the comparable periods in 2015 of \$50.49/bbl and \$42.43/bbl. The decline and persistence of low oil prices is due to an oversupply of oil in the global market.

WTI price increased in the second quarter of 2016, which resulted in an increase to the Company's average realized oil price by \$15.20/bbl and its combined average realized price by \$12.10/boe over the first quarter of 2016. The WTI prices have fluctuated in the low to mid \$40 range and the differential between WTI and Western Canadian Select pricing has improved in the third quarter of 2016, while the exchange rate has remained relatively stable.

In February the Company began trucking its sales oil from Jenner to a new sales point where it receives a premium of \$2.65/bbl. After subtracting the higher trucking costs of \$2.15/bbl the Company nets an additional \$0.50/bbl on Jenner oil sales which is equivalent to \$0.27/boe corporately.

The Company's average realized natural gas price decreased for the three and six months ended June 30, 2016 by \$1.44/Mcf and \$1.08/Mcf, respectively, from the comparable periods in 2015. These decreases are in line with the decline in AECO benchmark pricing for the three and six months ended June 30, 2016.

Revenue

	Three Months Ended June 30		Six Months Ended June 30	
	2016	2015	2016	2015
Oil	\$ 1,391,769	\$ 3,009,671	\$ 2,225,547	\$ 5,703,496
Natural gas	51,201	268,741	149,522	496,762
NGL	5,752	5,608	9,488	12,025
Total	\$ 1,448,722	\$ 3,284,020	\$ 2,384,557	\$ 6,212,284

Revenue for the three and six months ended June 30, 2016 decreased by 56% and 62% respectively, from the comparable periods in 2015. These decreases can be attributed to the reduction in the Company's overall production and the combined average realized price for the three and six months ended June 30, 2016.

The Company's revenue for the three months ended June 30, 2016 increased by 55% over the first quarter of 2016 as a result of the 60% increase in the Company's combined average realized price.

Operating Netback

	Three Months Ended June 30		Six Months Ended June 30	
	2016	2015	2016	2015
Operating netback				
Revenue	\$ 1,448,722	\$ 3,284,020	\$ 2,384,557	\$ 6,212,284
Royalties	106,759	214,321	215,878	456,032
Operating costs	545,568	889,930	1,075,246	1,498,427
Transportation costs	215,520	225,523	386,501	475,593
Operating netback	\$ 580,876	\$ 1,954,246	\$ 706,932	\$ 3,782,232
Operating netback (\$/boe)				
Revenue	\$ 32.34	\$ 42.49	\$ 26.19	\$ 37.24
Royalties	2.38	2.77	2.37	2.73
Operating costs	12.18	11.51	11.81	8.98
Transportation costs	4.81	2.92	4.25	2.85
Operating netback (\$/boe)	\$ 12.97	\$ 25.28	\$ 7.76	\$ 22.67

Royalties for the second quarter of 2016 were \$2.38/boe, representing a 14% decrease from the second quarter of 2015. For the six months ended June 30, 2016, royalties decreased by 13% from the comparable period in 2015. These reductions resulted from low oil prices which directly impact the Crown royalty par price.

Operating costs include all costs for gathering, processing, dehydration, compression, water processing and marketing of the oil, natural gas and NGLs, as well as additional costs incurred periodically for maintenance and repairs. Operating costs decreased on an absolute basis by 39% and 28% for the three and six months ended June 30, 2016 from the comparable periods in 2015. On a per boe basis, the operating costs increased by 6% (or \$0.66/boe) for the three months and by 31% (or \$2.83/boe) for the six months ended June 30, 2016 from the comparable periods in 2015.

The increase in operating costs is the result of additional workovers conducted on two wells during the period, as well as lower economies of scale for fixed costs resulting from reduced production in the period.

Transportation costs include all costs incurred to transport emulsion and oil and gas sales to processing and distribution facilities. Transportation costs increased for the three and six months ended June 30, 2016 by \$1.89/boe and \$1.39/boe, respectively, from the comparable periods in 2015. This increase is a result of trucking Jenner sales oil to a farther sales point to net a higher realized oil price, in addition to greater water trucking costs in Atlee since waterflood began. With successful results from the Atlee Buffalo waterflood pilots, the Company is now comfortable investing in a water handling facility at its battery in the Atlee Buffalo Upper Mannville F pool. Hemisphere expects to finish construction by the end of September 2016 which will reduce transportation and processing costs starting in the fourth quarter.

Operating netback for the three and six months ended June 30, 2016 were \$12.97/boe and \$7.76/boe, respectively. The Company experienced decreases in operating netback in 2016 as a result of the significant decline in commodity prices, despite reductions in royalties and the Company's successful efforts in cutting variable operating costs. Operating netback increased by \$10.24/boe over the first quarter of 2016 mainly as a result of the 60% increase in the Company's combined average realized price.

Exploration and Evaluation

Exploration and evaluation expenses generally consist of certain geological and geophysical costs, expiry of undeveloped lands, and costs of uneconomic exploratory wells. Exploration and evaluation expenses for the three months ended June 30, 2016 and 2015 were \$14,995 and \$6,908, respectively. For the six months ended June 30, 2016 and 2015, exploration and evaluation expenses were \$24,927 and \$14,300, respectively.

Depletion and Depreciation

	Three Months Ended June 30		Six Months Ended June 30	
	2016	2015	2016	2015
Depletion expense	\$ 686,251	\$ 1,447,286	\$ 1,370,689	\$ 3,089,333
Depreciation expense	2,489	3,364	4,977	6,727
Total	\$ 688,740	\$ 1,450,649	\$ 1,375,666	\$ 3,096,060
\$ per boe	\$ 15.37	\$ 18.77	\$ 15.11	\$ 18.56

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 to develop and produce undeveloped and non-producing reserves. Depletion and depreciation expense for the second quarter of 2016 decreased by \$761,909 over the second quarter of 2015. For the six months ended June 30, 2016, depletion and depreciation expense decreased by \$1,720,394 over the comparable period in 2015.

The significant decreases in depletion expense for these periods as compared to the comparative periods of 2015 are due to a lower depletion rate, which is computed from the lower production rates that are divided by the higher remaining reserve base from the December 31, 2015 external engineers' evaluation report.

Capital Expenditures

	Three Months Ended June 30		Six Months Ended June 30	
	2016	2015	2016	2015
Land and lease	\$ 2,016	\$ 5,600	\$ 9,576	\$ 13,034
Geological and geophysical	64,637	28,408	120,021	44,440
Drilling and completions	49,289	283,407	325,431	333,106
Facilities and infrastructure	88,466	241,080	94,056	301,204
Development capital	204,407	558,495	549,083	691,783
Property acquisitions	-	271,000	-	271,000
Total capital expenditures ⁽¹⁾	\$ 204,407	\$ 829,495	\$ 549,083	\$ 962,783

Note:

(1) Total capital expenditures exclude decommissioning obligations.

The development capital spent during the first six months of 2016 included the conversion of a water injection well in Atlee Buffalo, various pump size upgrades to optimize production levels, and some upfront expenditures for the Atlee Buffalo Upper Mannville F pool water handling facility.

General and Administrative Expenses ("G&A")

	Three Months Ended June 30		Six Months Ended June 30	
	2016	2015	2016	2015
Gross G&A	\$ 341,958	\$ 565,333	\$ 651,104	\$ 1,036,235
Capitalized G&A and overhead recoveries	(57,423)	(47,842)	(115,770)	(55,301)
Total	\$ 284,535	\$ 517,491	\$ 535,333	\$ 980,934
\$ per boe	\$ 6.35	\$ 6.70	\$ 5.88	\$ 5.88

Gross G&A for the second quarter of 2016 decreased by \$223,376 over the comparable quarter in 2015 due to significant reductions in staffing costs, legal fees, and investor relations activities. For the six months ended June 30, 2016, gross G&A decreased by \$385,131 over the comparable period in 2015.

The Company capitalizes certain G&A which can be attributed to any costs incurred during the period relating to its development and exploration activities. For the three and six months ended June 30, 2016, capitalized G&A increased by \$9,581 and \$60,469, respectively, from the comparable periods in 2015. These increases in capitalized G&A are in relation to the Company's conformance with IFRS procedures effective as of the third quarter of 2015.

For the three and six months ended June 30, 2016, the Company realized decreases in total G&A of \$232,957 and \$445,601, respectively, from the comparable periods in 2015 as a result of significant reductions in overall general and administrative costs.

Share-based Payments

Share-based payments are non-cash charges which reflect the estimated value of stock options issued to directors, employees and consultants of the Company. Share-based payments for the three months ended June 30, 2016 and 2015 were \$1,093 and \$2,742, respectively. The Company granted 1,785,000 incentive stock options in the first quarter of 2016 of which 75,000 will vest quarterly over a twelve-month period. In the second quarter of 2016, 18,750 stock options vested resulting in the recognition of \$1,093 in share-based payments. For the six months ended June 30, 2016 and 2015, the Company recorded share-based payments of \$87,484 and \$221,752, respectively.

Finance Expense

	Three Months Ended June 30		Six Months Ended June 30	
	2016	2015	2016	2015
Finance expense				
Interest expense	\$ 136,447	\$ 115,775	\$ 259,218	\$ 223,783
Accretion of provision	35,792	31,066	71,583	62,131
Total	\$ 172,239	\$ 146,841	\$ 330,801	\$ 285,914
\$ per boe	\$ 3.84	\$ 1.90	\$ 3.63	\$ 1.71

Finance expense for the three and six months ended June 30, 2016 increased by \$25,399 and \$44,887, respectively, over the comparable periods in 2015. These increases are a result of the increased accretion expense for the periods, and the interest expense incurred on the utilization of the Company's credit facility which carried a higher balance in 2016.

Accretion expense represents the adjusted present value of the Company's decommissioning obligations which includes the abandonment and reclamation costs associated with wells and facilities. For the

three and six months ended June 30, 2016, accretion expense increased by \$4,727 and \$9,452, respectively, over the comparable periods in 2015 due to the additional decommissioning obligations associated with the new wells drilled in the second half of 2015.

Tax Pools and Deferred Taxes

As at December 31, 2015, the Company had 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 2016. Taxes payable beyond 2016 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 a non-IFRS measure that represents cash generated by operating activities, before changes in non-cash working capital and may not be comparable to measures used by other companies.
- (2) Certain annual amounts were restated retrospectively 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

	2016			2015			2014	
	June. 30 Q2 ⁽²⁾	Mar. 31 Q1 ⁽³⁾	Dec. 31 Q4 ⁽⁴⁾	Sep. 30 Q3 ⁽⁵⁾	June. 30 Q2 ⁽⁶⁾	Mar. 31 Q1 ⁽⁷⁾	Dec. 31 Q4 ⁽⁸⁾	Sep. 30 Q3 ⁽⁹⁾
Average daily production (boe/d)	492	508	588	678	849	995	885	725
Petroleum and natural gas revenue	1,448,722	935,834	1,493,313	2,043,781	3,284,020	2,928,264	4,568,286	4,703,496
Petroleum and natural gas netback	580,876	126,056	458,240	1,094,625	1,954,246	1,827,986	2,534,334	2,852,204
Funds flow from operations	159,894	(247,514)	(103,531)	714,505	1,314,073	1,249,142	1,334,422	2,279,842
Per share, basic and diluted	0.00	(0.00)	(0.00)	0.01	0.02	0.02	0.02	0.03
Net income (loss) ⁽¹⁾	(580,725)	(1,066,556)	(2,333,468)	(4,755,531)	(575,484)	(646,345)	(3,568,603)	720,312
Basic and diluted income (loss) per share	(0.01)	(0.01)	(0.03)	(0.06)	(0.01)	(0.01)	(0.05)	0.01
Combined average realized price (\$/boe)	32.34	20.24	27.59	32.74	42.49	32.71	56.10	70.52
Operating netback (\$/boe)	12.97	2.73	8.47	17.54	25.28	20.42	31.14	42.79

Notes:

- (1) Certain quarterly amounts were restated retrospectively 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.
- (2) The increase in revenue and netbacks, and the resulting reduced loss in this quarter over the previous quarter is due primarily to an improvement in commodity prices.
- (3) The decreases in net income, funds flow from operations and petroleum and natural gas netbacks for this quarter can be attributed to the decrease in the Company's combined average realized price resulting from the decline in commodity prices, and lower production volumes.
- (4) A significant portion of the loss in this quarter 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.
- (5) 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.
- (6) 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.
- (7) 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.
- (8) 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.
- (9) 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.

Outstanding Share Capital

	August 25, 2016	June 30, 2016	December 31, 2015
Fully diluted share capital			
Common shares issued and outstanding	85,670,102	81,095,998	75,803,498
Stock options	4,535,000	4,535,000	5,995,000
Total fully diluted	90,205,102	85,630,998	81,798,498

Subsequent to June 30, 2016, the following event impacted the Company's share capital:

On July 12, 2016 the Company closed of the final tranche of its non-brokered private placement offering. In connection with the closing of the final tranche, the Company issued 527,000 flow-through shares at a price of \$0.21 per share, which were issued on a Canadian Development Expense flow-through basis pursuant to the provisions of the *Income Tax Act*, and 4,047,104 common shares of Hemisphere at a price of \$0.19 per share, for gross proceeds to the Company of \$879,620. The aggregate funds raised by Hemisphere under the first and second closings of the Offering totaled \$1,921,055.

The Company has the following stock options outstanding and exercisable as at August 25, 2016:

Exercise Price	Expiry Date	Balance Outstanding	Balance Exercisable
		August 25, 2016	August 25, 2016
\$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	1,628,750
\$0.08	12-Feb-21	200,000	200,000
		4,535,000	4,478,750
Weighted-average exercise price		\$0.32	\$0.32

Liquidity and Capital Management

The Company's net debt as at June 30, 2016 and December 31, 2015 were \$11,062,899 and \$11,446,110, respectively, representing a decrease in net debt of \$383,221.

a) Financing

As per the condensed Statement of Cash Flows, the Company's cash provided by financing activities for the three months ended June 30, 2016 was \$469,947. The changes in bank indebtedness for the three months ended June 30, 2016, and 2015 were decreases of \$549,965, and \$534,501, respectively. For the six months ended June 30, 2016 and 2015, cash provided by financing activities were \$1,175,568 and \$2,363,437, which includes the increase in bank indebtedness of \$155,656, and \$2,254,687 respectively.

During the six months ended June 30, 2016, the following equity transactions occurred:

- (i) On April 7, 2016, the Company issued 100,000 common shares for the exercise of stock options at \$0.08 per share for proceeds of \$8,000
- (ii) On June 29, 2016 the Company closed the first tranche of its non-brokered private placement offering. The Company issued 2,743,000 flow-through shares at a price of \$0.21 per share, which were issued on a Canadian Development Expense flow-through basis pursuant to the provisions of the *Income Tax Act* (Canada), and 2,449,500 common shares of Hemisphere at a price of \$0.19 per share, for gross proceeds to the Company of \$1,041,435. In conjunction with closing the financing, the Company paid \$29,524 in share issuance costs.

b) Capital Resources

	As at	
	June 30, 2016	December 31, 2015
Credit Facilities		
Authorized limit	\$ 12,500,000	15,000,000
Drawn amount	10,983,696	10,828,040
Undrawn amount	\$ 1,516,304	4,171,960

The Company has a demand operating credit facility in the amount of \$12.5 million with Alberta Treasury Branches ("ATB"), which was renewed in May 2016. 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 2.50%, as well as a standby charge for any undrawn funds.

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, to current liabilities, excluding any current bank indebtedness.

At June 30, 2016, the Company had drawn a total of \$10,983,696 from its credit facility (December 31, 2015 - \$10,828,040) and had a working capital ratio of 2.2, which is in compliance with the above financial covenant. The Company's next credit facility review with ATB is set for November 2016.

The Company manages its capital with the following objectives:

- Ensure sufficient flexibility to achieve the Company's ongoing business objectives including the replacement of production, funding of future growth opportunities, and pursuit of accretive acquisitions; and
- Maximize shareholder return through enhancing the Company's share value.

The Company monitors its capital structure and makes adjustments according to market conditions in an effort to meet its objectives given the current outlook of the business and industry in general. The capital structure of the Company is composed of shareholders' equity and the undrawn component of the Company's credit facilities. 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.

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 four fiscal years:

			2016	2017	2018
Rental commitment	\$	\$	96,730	\$ 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 and Judgements

The Company's significant accounting estimates, judgements 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 unaudited interim condensed financial statements.

The preparation of the unaudited interim condensed financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that may affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates. A discussion of specific estimates and judgements employed in the preparation of the Company's unaudited interim condensed financial statements is included in the Company's audited annual financial statements for the year ended December 31, 2015.

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

Newly Adopted Accounting Standards

Effective January 1, 2016, the Company has not adopted any new accounting standards. A full listing of future accounting pronouncements are disclosed in the Company's annual audited financial statements for the year ended December 31, 2015.

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 June 30, 2016, 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	
	June 30, 2016	December 31, 2015
Accounts receivable		
Trade receivables	\$ 1,038,256	\$ 385,432
Receivables from joint venture	30,675	153,897
Reclamation deposits	115,535	115,535
Total	\$ 1,184,467	\$ 654,864

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

Liquidity risk

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

regularly monitored and updated when necessary in order to review debt forecasts and working capital requirements.

At June 30, 2016, the Company had net debt of \$11,062,899 (December 31, 2015 - \$11,446,110), which includes bank indebtedness of \$10,983,696 (December 31, 2015 - \$10,828,040). 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 income (loss) and comprehensive income (loss).

Foreign currency risk

The Company's functional and reporting currency is Canadian dollars. The Company does not sell or transact in any foreign currency; 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 funds flow from operations, and 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 Measures

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

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

	Three Months Ended June 30		Six Months Ended June 30	
	2016	2015	2016	2015
Cash provided by operating activities	\$ (74,079)	\$ 918,676	\$ (413,187)	\$ 1,761,127
Change in non-cash working capital	233,974	399,714	325,567	813,796
Decommissioning obligation expenditures	-	2,591	-	2,591
Funds flow from operations	\$ 159,894	\$ 1,320,981	\$ (87,620)	\$ 2,577,514
Per share, basic and diluted	\$ 0.00	\$ 0.02	\$ (0.00)	\$ 0.03

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

The following table outlines the Company calculation of net debt:

	As at	
	June 30, 2016	December 31, 2015
Current assets	\$ 1,169,550	\$ 686,869
Current liabilities ⁽¹⁾	(1,248,754)	(1,304,939)
Bank indebtedness	(10,983,696)	(10,828,040)
Net debt	\$ (11,062,899)	\$ (11,466,110)

Note:

(1) Excluding bank indebtedness.

Boe Conversion

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

Forward-Looking Statements

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

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

Although Hemisphere believes that the expectations reflected in the forward-looking statements contained in this MD&A, and the assumptions on which such forward-looking statements are made, are reasonable, there can be no assurance that such expectations will prove to be correct. Readers are cautioned not to place undue reliance on forward-looking statements included in this MD&A, as there can be no assurance that the plans, intentions or expectations upon which the forward-looking statements are based will occur. By their nature, forward-looking statements involve numerous assumptions, known and unknown risks and uncertainties that contribute to the possibility that the predictions, forecasts, projections and other forward-looking statements will not occur, which may cause Hemisphere's actual performance and financial results in future periods to differ materially from any estimates or projections of future performance or results expressed or implied by such forward-looking statements. These risks and uncertainties include, among other things, the following: volatility in market prices for oil and natural gas; general economic conditions in Canada, the U.S. and globally; and the

other factors described under "Risk Factors" in Hemisphere's most recently filed Annual Information Form available on the Company's website at www.hemisphereenergy.ca or on SEDAR at www.sedar.com. Readers are cautioned that this list of risk factors should not be construed as exhaustive.

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