## MANAGEMENT'S DISCUSSION AND ANALYSIS

Dated as at November 23, 2017

The following Management's Discussion and Analysis ("MD&A") is a review of the operations and current financial position for the three and nine months ended September 30, 2017 for Hemisphere Energy Corporation ("Hemisphere" or the "Company") and should be read in conjunction with the unaudited interim condensed financial statements and related notes for the three and nine months ended September 30, 2017, and the audited annual financial statements and related notes for the year ended December 31, 2016. These documents and additional information relating to the Company, including the Company's Annual Information Form, are available on SEDAR at www.sedar.com or the Company's website at www.hemisphereenergy.ca.

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

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

### Business Overview

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

**Jenner, Alberta**

Hemisphere has a 100% working interest in 23,810 net acres and has continued to build a land position in the Jenner area through Crown land sales and strategic acquisitions. The property is accessible year-round and is located east of Brooks in southeastern Alberta.

**Atlee Buffalo, Alberta**

The Company operates 100% of its wells in the Atlee Buffalo area. The property is accessible year-round and is located 30 kilometres east of the Company's Jenner property in southeastern Alberta. Hemisphere has a 100% working interest in 7,040 net acres and has been building a land position in Atlee Buffalo through Crown land sales and strategic acquisitions since 2013.

### Operating Results

The Company generated funds flow from operations of $657,840 ($0.01/share) during the third quarter of 2017, as compared to $345,007 ($0.00/share) during the third quarter of 2016. Funds flow for the nine months ended September 30, 2017 increased to $1,761,249 ($0.02/share) from $257,387

($0.00/share) for the same period in 2016. These improvements are due to the Company's increased revenues, increased production and commodity prices, and realized commodity hedging gains.

For the three and nine months ended September 30, 2017, the Company reported net losses of $142,254 ($0.00/share) and $487,655 ($0.01/share), respectively, compared to net losses of $413,340 ($0.00/share) and $2,060,620 ($0.03/share) for the three and nine months ended September 30, 2016, respectively.

### Production

| | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| **By product:** | **2017** | 2016 | **2017** | 2016 |
| Oil (bbl/d) | **644** | 450 | **574** | 422 |
| Natural gas (Mcf/d) | **217** | 400 | **274** | 493 |
| NGL (bbl/d) | **1** | 2 | **2** | 2 |
| Total (boe/d) | **681** | 518 | **622** | 506 |
| Oil and NGL weighting | **95%** | 87% | **93%** | 84% |

In the third quarter of 2017, the Company's average daily production was 681 boe/d (95% oil and NGL) representing a 31% increase over the comparable quarter in 2016 despite a loss in volumes due to downtime from facility work during the quarter. For the nine months ended September 30, 2017, the Company's average daily production was 622 boe/d (93% oil and NGL), representing a 23% increase from 506 boe/d (84% oil and NGL) for the same period in 2016. These production increases are attributed to the Company's continued success of its waterfloods in the Upper Mannville F and G pools in Atlee Buffalo with the addition of one new well in the Upper Mannville G pool in 2016, and stable production at Jenner.

### Average Benchmark and Realized Prices

| | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| | **2017** | 2016 | **2017** | 2016 |
| **Benchmark prices** | | | | |
| WTI ($USD/bbl)[1] | **$ 48.20** | $ 44.94 | **$ 49.46** | $ 41.33 |
| Exchange rate (1 $USD/$C) | **1.2529** | 1.3041 | **1.3056** | 1.3206 |
| WTI ($C/bbl) | **60.39** | 58.61 | **64.57** | 54.58 |
| WCS ($C/bbl)[2] | **47.93** | 41.00 | **49.10** | 36.30 |
| AECO natural gas ($/Mcf)[3] | **1.61** | 2.36 | **2.36** | 1.87 |
| | | | | |
| **Average realized prices** | | | | |
| Crude oil ($/bbl) | **45.58** | 37.28 | **46.20** | 32.58 |
| Natural gas ($/Mcf) | **1.48** | 2.24 | **2.42** | 1.72 |
| NGL ($/bbl) | **42.62** | 32.88 | **45.41** | 26.05 |
| Combined ($/boe) | **$ 43.62** | $ 34.19 | **$ 43.87** | $ 28.94 |

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

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

The Company's combined average realized price increased by 28% from $34.19/boe during the three months ended September 30, 2016 to $43.62/boe during the three months ended September 30, 2017. The Company's combined average realized price increased by 52% from $28.94/boe during the nine months ended September 30, 2016 to $43.87/boe during the nine months ended September 30, 2017. These increases are the result of higher oil prices during the three and nine months ended September 30, 2017 which are reflected in the respective $8.30/bbl and $13.62/bbl increases from the Company's average realized crude oil price during the same periods in 2016.

The Company's average realized natural gas price decreased by $0.76/Mcf in the three months ended September 30, 2017 and increased by $0.70/Mcf in the nine months ended September 30, 2017 from the comparable periods in 2016.

As at the date of this MD&A, the Company held derivative commodity contracts as follows:

| Product | Type | Volume | Price | Index | Term |
|---|---|---|---|---|---|
| Crude oil | Swap | 300 bbl/d | USD$50.67 | WTI-NYMEX | September 1, 2017 – December 31, 2017 |
| Crude oil | Swap(1) | 150 bbl/d | USD$54.65 | WTI-NYMEX | November 1, 2017 – June 30, 2018 |
| Crude oil | Option(1) | 150 bbl/d | USD$54.65 | WTI-NYMEX | July 1, 2018 – February 28, 2019 |
| Crude oil | Swap | 300 bbl/d | USD$50.67 | WTI-NYMEX | January 1, 2018 – December 31, 2018 |
| Crude oil | Swap | 250 bbl/d | USD$50.67 | WTI-NYMEX | January 1, 2019 – December 31, 2019 |
| Crude oil | Swap | 200 bbl/d | USD$50.67 | WTI-NYMEX | January 1, 2020 – August 1, 2020 |

*Note:*

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

At September 30, 2017, the commodity contracts were fair valued as an asset of $221,129 recorded on the balance sheet, and unrealized gains of $190,999 and $221,129 were recorded for the three and nine months ended September 30, 2017, respectively.

### Revenue

| | | Three Months Ended September 30 | | | | Nine Months Ended September 30 | | |
|---|---|---|---|---|---|---|---|---|
| | | **2017** | | 2016 | | **2017** | | 2016 |
| Oil | **$** | **2,698,497** | $ | 1,541,839 | **$** | **7,245,314** | $ | 3,767,387 |
| Natural gas | | **29,473** | | 82,577 | | **180,948** | | 232,098 |
| NGL | | **5,686** | | 5,689 | | **19,806** | | 15,177 |
| Total | **$** | **2,733,656** | $ | 1,630,105 | **$** | **7,446,068** | $ | 4,014,662 |

Revenue for the three and nine months ended September 30, 2017 increased by 68% and 85%, respectively, from the comparable periods in 2016. These increases are attributed to the $9.43/boe and $14.93/boe increases in the Company's combined average realized prices, and increases in production by 31% and 23% during the respective periods.

## Operating Netback

| | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| | **2017** | 2016 | **2017** | 2016 |
| **Operating netback** | | | | |
| Revenue | **$ 2,733,656** | $ 1,630,105 | **$ 7,446,068** | $ 4,014,662 |
| Royalties | **586,468** | 221,303 | **1,278,205** | 437,181 |
| Operating costs | **801,017** | 377,468 | **2,598,837** | 1,452,713 |
| Transportation costs | **169,968** | 251,369 | **484,317** | 637,870 |
| Operating field netback(1) | **$ 1,176,204** | $ 779,966 | **$ 3,084,709** | $ 1,486,898 |
| Realized commodity hedging gain (loss) | **31,902** | - | **178,085** | - |
| Operating netback(2) | **$ 1,208,106** | $ 779,966 | **$ 3,262,794** | $ 1,486,898 |
| **Operating netback ($/boe)** | | | | |
| Revenue | **$ 43.62** | $ 34.19 | **$ 43.87** | $ 28.94 |
| Royalties | **9.36** | 4.64 | **7.53** | 3.15 |
| Operating costs | **$ 12.78** | $ 7.92 | **$ 15.31** | $ 10.47 |
| Transportation costs | **2.71** | $ 5.27 | **2.85** | $ 4.60 |
| Operating field netback(1) | **$ 18.77** | $ 16.36 | **$ 18.18** | $ 10.72 |
| Realized commodity hedging gain (loss) | **0.51** | - | **1.05** | - |
| Operating netback(2) | **$ 19.28** | $ 16.36 | **$ 19.22** | $ 10.72 |

*Notes:*

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

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

Royalties for the three months ended September 30, 2017 were $9.36/boe, representing a 102% increase from the three months ended September 30, 2016. Royalties for the nine months ended September 30, 2017 were $7.53/boe, representing a 139% increase from the same period in 2016. These increases are a result of higher oil prices, increased oil production rates from the Company's waterflood projects in the Atlee Buffalo F pool, the expiration of the royalty holiday period for some of the Company's wells, and a gross overriding royalty adjustment allocated through December 31, 2017.

Operating costs include all costs for gathering, processing, dehydration, compression, water processing and marketing of the oil, natural gas and NGLs, as well as additional costs incurred periodically for maintenance and repairs. Operating costs for the three and nine months ended September 30, 2017 increased by $4.86/boe and $4.84/boe, respectively, over the same periods in 2016. The increases are the result of facility maintenance and well workovers.

Transportation costs include all costs incurred to transport emulsion and oil and gas sales to processing and distribution facilities. Transportation costs were $2.71/boe during the third quarter of 2017, which is a 49% decrease from the comparable quarter in 2016. Transportation costs were $2.85/boe for the nine months ended September 30, 2017, which is a 38% decrease from the same period in 2016. These decreases are attributable to reduced trucking rates, closer sales points, and the result of eliminating trucking of water to a third-party from the Atlee Buffalo F pool with the construction of a facility to separate and re-inject water in the fourth quarter of 2016.

Operating netback for the three and nine months ended September 30, 2017 were higher than the comparable periods in 2016 at $19.28/boe and $19.22/boe, respectively. These increases are mainly due to the 28% and 52% increases in the Company's combined average realized prices and higher production rates for the respective periods as discussed above. In addition, the Company held derivative commodity contracts during the three and nine months ended September 30, 2017 which resulted in realized hedging gains of $0.51/boe and $1.05/boe, respectively, and are included in the operating netback.

**Exploration and Evaluation**

Exploration and evaluation expense generally consists of certain geological and geophysical costs, expiry of undeveloped lands, and costs of uneconomic exploratory wells. Exploration and evaluation expenses for the three months ended September 30, 2017 and 2016 were $9,295 and $12,023, respectively. For the nine months ended September 30, 2017 and 2016, exploration and evaluation expenses were $33,385 and $36,950, respectively.

**Depletion and Depreciation**

| | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| | **2017** | 2016 | **2017** | 2016 |
| Depletion expense | **$ 851,854** | $ 706,951 | **$ 2,247,860** | $ 2,077,641 |
| Depreciation expense | **1,845** | 2,489 | **5,533** | 7,465 |
| Total | **$ 853,699** | $ 709,440 | **$ 2,253,393** | $ 2,085,106 |
| $ per boe | **$ 15.64** | $ 14.88 | **$ 13.28** | $ 15.03 |

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

Depletion and depreciation expenses for the three months ended September 30, 2017 increased to $15.64/boe from $14.88/boe for the same period in 2016. For the nine months ended September 30, 2017, depletion and depreciation expenses decreased to $13.28/boe from $15.03/boe for the same period in 2016. The increase in the quarter ended September 30, 2017 over the comparable quarter in 2016 is due primarily to the increased production over the comparable quarter. The overall decrease in depletion expenses for the nine months ended September 30, 2017 as compared to the same period in 2016 is due to amortization of production over a larger reserve volume base from the Company's December 31, 2016 independent engineers evaluation report as prepared by McDaniel and Associates Consultants Ltd.

**Capital Expenditures**

| | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| | **2017** | 2016 | **2017** | 2016 |
| Land and lease | **$ 12,096** | $ 12,096 | **$ 24,800** | $ 21,672 |
| Geological and geophysical | **12,229** | 53,305 | **165,878** | 173,326 |
| Drilling and completions | **2,294,155** | 701,986 | **2,453,732** | 1,027,416 |
| Facilities and infrastructure | **789,498** | 690,144 | **1,381,389** | 784,199 |
| Total capital expenditures(1) | **$ 3,107,979** | $ 1,457,530 | **$ 4,025,800** | $ 2,006,613 |

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

The development capital spent during the nine months ended September 30, 2017 included capital associated with the start of a six well drilling program, expansion of the Upper Mannville F pool battery, construction of the Upper Mannville G pool battery, installation of a larger downhole pump in a producing well, installation of a transfer pump to further reduce operating costs, wellsite electrification work, and addition of a new tank and burner system.

## General and Administrative

| | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| | **2017** | 2016 | **2017** | 2016 |
| Gross general and administrative | **$ 456,723** | $ 379,855 | **$ 1,281,345** | $ 1,030,958 |
| Capitalized general and administrative | **(89,649)** | (81,011) | **(249,052)** | (196,781) |
| Total | **$ 367,074** | $ 298,844 | **$ 1,032,293** | $ 834,177 |
| $ per boe | **$ 5.86** | $ 6.27 | **$ 6.08** | $ 6.01 |

Gross general and administrative expenses for the three and nine months ended September 30, 2017 increased by 20% and 24%, respectively, over the same periods in 2016 due to increased activity resulting in increased consulting fees and salaries.

The Company capitalizes some general and administrative expenses which can be attributed to any costs incurred during the period relating to its development and exploration activities. For the three and nine months ended September 30, 2017, capitalized general and administrative expenses increased by $8,638 and $52,271, respectively, from the comparable periods in 2016.

For the three months ended June 30, 2017, the Company realized a decrease of $0.41/boe in general and administrative costs from the same period in 2016 as a result of increased production which offset the increase gross general and administrative expenses for the quarter. Over the nine months ended September 30, 2017, the Company had a slight increase of $0.07/boe to general and administrative costs from the comparable period in 2016.

## Share-based Payments

During the third quarter of 2017, the Company granted 5,034,000 stock options to directors, officers, employees and consultants at an exercise price of $0.25 each, of which 1,678,000 vested immediately. The Company uses a Black-Scholes option pricing model to calculate the fair value of stock option grants where the corresponding expense is recognized over the option vesting period. The total valuation of the vested options from the grant was $309,057, of which $214,387 was expensed as stock-based compensation and $94,670 was capitalized.

| | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| | **2017** | 2016 | **2017** | 2016 |
| Share-based payments | **$ 214,387** | $ 1,094 | **$ 215,480** | $ 88,577 |
| Capitalized costs | **94,670** | - | **94,670** | 26,892 |
| Total share-based payments | **$ 309,057** | $ 1,094 | **$ 310,150** | $ 115,469 |

## Finance Expense

| | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| | **2017** | 2016 | **2017** | 2016 |
| Cash interest expense | **$ 165,368** | $ 136,115 | **$ 451,429** | $ 395,334 |
| Amortization of deferred charges | **13,800** | - | **13,800** | - |
| Accretion of debt issuance costs | **2,285** | - | **2,285** | - |
| Accretion of decommissioning liabilities | **26,932** | 35,791 | **80,795** | 107,374 |
| Total | **$ 208,386** | $ 171,907 | **$ 548,310** | $ 502,708 |
| $ per boe | **$ 3.33** | $ 3.61 | **$ 3.23** | $ 3.62 |

Finance expense for the three and nine months ended September 30, 2017 increased by 21% and 9%, respectively, from the comparable periods in 2016. This is due primarily to a higher average debt balance, including the replacement of the credit facility with a higher term loan balance and interest rate in September 2017 which includes the amortization and accretion of debt issuance costs.

Accretion of decommissioning liabilities represents the adjusted present value of the Company's decommissioning obligations which include the abandonment and reclamation costs associated with wells and facilities. In the three and nine months ended September 30, 2017, accretion of decommissioning liabilities decreased by 25% for both periods from the comparable periods in 2016 due to a decrease in the total estimated costs of abandonment and reclamation obligations year-over-year.

### Tax Pools

As at December 31, 2016, the Company had approximately $48 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 2017. Taxes payable beyond 2017 will primarily be a function of commodity prices, capital expenditures, and production volumes.

| | Deduction Rate | **December 31, 2016** | December 31, 2015 |
|---|---|---|---|
| Canadian exploration expense (CEE) | 100% | **$ 3,336,823** | $ 3,336,823 |
| Canadian development expense (CDE) | 30% | **14,879,326** | 19,220,505 |
| Canadian oil and gas property expense (COGPE) | 10% | **6,765,679** | 7,517,421 |
| Non-capital losses carry forwards (NCL) | 100% | **21,122,443** | 13,734,893 |
| Undepreciated capital cost (UCC) | 20-55% | **1,571,468** | 2,171,731 |
| Share issuance costs and other | Various | **581,463** | 797,356 |
| **Total** | | **$ 48,257,202** | $ 46,778,729 |

## Summary of Quarterly Results

| | **2017** | | | 2016 | | | | 2015 |
|---|---|---|---|---|---|---|---|---|
| | **Sep. 30 Q3(1)** | Jun. 30 Q2(1) | Mar. 31 Q1(2) | Dec. 31 Q4(3) | Sep. 30 Q3(4) | Jun. 30 Q2(5) | Mar. 31 Q1(6) | Sep. 30 Q3(7) |
| Average daily production (boe/d) | **681** | 600 | 583 | 590 | 518 | 492 | 508 | 678 |
| Petroleum and natural gas revenue | **2,733,656** | 2,419,666 | 2,292,746 | 2,206,835 | 1,630,105 | 1,448,722 | 935,834 | 2,043,781 |
| Petroleum and natural gas netback (excluding hedging) | **1,176,204** | 989,681 | 918,824 | 860,849 | 779,966 | 580,876 | 126,056 | 1,094,625 |
| Funds flow from/used in operations | **657,840** | 598,078 | 505,331 | 273,181 | 345,007 | 159,894 | (247,514) | 714,505 |
| Per share, basic and diluted | **0.01** | 0.01 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 |
| Net income (loss) | **(142,254)** | (206,724) | (138,678) | (620,027) | (413,340) | (580,725) | (1,066,556) | (4,755,531) |
| Per share, basic and diluted | **(0.00)** | (0.00) | (0.00) | (0.01) | (0.00) | (0.01) | (0.01) | (0.06) |
| Combined average realized price ($/boe) | **43.62** | 44.34 | 43.68 | 40.63 | 34.19 | 32.34 | 20.24 | 32.74 |
| Operating netback ($/boe) | **19.28** | 20.09 | 18.26 | 15.85 | 16.36 | 12.97 | 2.73 | 17.54 |

*Notes:*

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

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

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

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

(5) *The increases in revenue and netbacks, and the resulting reduced loss in this quarter over the previous quarter is due primarily to an improvement in commodity prices.*

(6) *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.*

(7) *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.*

## Outstanding Share Capital

| | November 23, 2017 | **September 30, 2017** | December 31, 2016 |
|---|---|---|---|
| Fully diluted share capital | | | |
| Common shares issued and outstanding | 89,793,302 | **89,793,302** | 85,745,102 |
| Stock options | 8,169,000 | **8,019,000** | 4,385,000 |
| Warrants | 13,750,000 | **13,750,000** | - |
| Total fully diluted shares | 111,562,302 | **111,562,302** | 90,130,102 |

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

The Company has the following stock options that are outstanding and exercisable as at November 23, 2017:

| Exercise Price | Grant Date | Expiry Date | Balance Outstanding November 23, 2017 | Balance Exercisable November 23, 2017 |
|---|---|---|---|---|
| $0.24 | January 29, 2015 | January 29, 2020 | 1,075,000 | 1,075,000 |
| $0.39 | March 1, 2015 | March 1, 2020 | 100,000 | 100,000 |
| $0.08 | February 11, 2016 | February 11, 2021 | 1,685,000 | 1,685,000 |
| $0.08 | February 12, 2016 | February 12, 2021 | 125,000 | 125,000 |
| $0.25 | September 21, 2017 | September 21, 2022 | 5,034,000 | 1,678,000 |
| $0.28 | October 2, 2017 | October 2, 2022 | 150,000 | 50,000 |
| | | | 8,169,000 | 4,713,000 |
| Weighted-average exercise price | | | $0.21 | $0.18 |

Stock options granted on September 21, 2017 and October 2, 2017 are subject to a vesting schedule whereby one-third vested immediately, one-third vests on the first anniversary, and one-third vests on the second anniversary of the grant date.

Subsequent to the end of the third quarter, on October 2, 2017, the Company granted an employee 150,000 stock options at an exercise price of $0.28 per share of which one-third vested immediately, one-third vests on the first anniversary, and one-third vests on the second anniversary of the grant date.

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

## Liquidity and Capital Management

The Company's net debt as at September 30, 2017 and December 31, 2016 were $14,426,091 and $11,827,170, respectively, representing an 22% increase in net debt since year-end 2016.

a) Financing

The Company's cash provided by financing activities during the nine months ended September 30, 2017 and 2016 were $888,093 and $1,653,398, respectively. This includes the proceeds of $11,087,883, net of debt issuance costs, which the Company received from the initial draw on the new term loan on September 15, 2017 (as further disclosed in Note 10 of the Company's interim condensed financial statements for the three and nine months ended September 30, 2017). This initial draw was primarily used to payout the balance of the Company's bank credit facility in full.

On April 27, 2017, 4,048,200 flow-through shares were issued at a price of $0.28/share through a non-brokered private placement offering for a gross proceeds of $1,133,496.

b) Credit Facility

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

c) Term Loan

On September 15, 2017, the Company entered into a first lien senior secured credit agreement (the "Credit Agreement") with a third-party lender (the "Lender") providing for a multi-draw, non-revolving term loan facility of a maximum aggregate principal amount of up to USD$35.0 million. An initial commitment amount of USD$15.0 million (the "Term Loan") was granted at inception, of which USD$10.0 million was drawn at September 30, 2017. The Company's ability to access additional commitments in excess of USD$15.0 million is subject to approval of the Lender based on review and approval of the Company's future development plans.

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

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

1. Interest coverage ratio for the quarter ended June 30, 2018 shall not be less than 2.00 to 1.00; quarter ended September 30, 2018 shall not be less than 2.25 to 1.00; quarter ended December 31, 2018 shall not be less than 2.50 to 1.00; quarter ended March 31, 2019 and each quarter thereafter shall not be less than 3.00 to 1.00.

Interest coverage ratio, as defined in the Credit Agreement, means the ratio as of the last day of any fiscal quarter of (a) Consolidated Adjusted EBITDAX as defined below for the applicable fiscal quarter to (b) Consolidated Interest Expense for such fiscal quarter.

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

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

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

4. Proved developed producing coverage ratio for the quarter ended June 30, 2018 and each quarter thereafter shall not be less than 1.00 to 1.00.

   Proved developed producing coverage ratio, as defined in the Credit Agreement, means as of any date of determination, the ratio of (a) PV10 of proved developed producing reserves to (b) the sum of (i) Consolidated Total Debt and (ii) without duplication of clause (a) above, all obligations (after giving effect to any netting requirements) under any swap agreement that such person would be required to pay if the swap agreement was terminated at such time, in each case, as of such date. Notwithstanding anything to the contrary contained herein, after giving effect to the netting contemplated by clause (ii) above, in no event shall amounts owing to the Company under any swap agreement result in a reduction of the obligations referred to in clause (b).

5. Total proved reserves coverage ratio for the quarter ended June 30, 2018 and each quarter thereafter shall not be less than 1.50 to 1.00.

   Total proved reserves coverage ratio, as defined in the Credit Agreement, means as of any date of determination, the ratio of (a) the Total Proved PV10 Value to (b) the sum of (i) Consolidated Total Debt and (ii) without duplication of clause (a) above, all obligations (after giving effect to any netting requirements) under any swap agreement that such person would be required to pay if the swap agreement were terminated at such time, in each case, as of such date. Notwithstanding anything to the contrary contained herein, after giving effect to the netting contemplated by clause (ii) above, in no event shall amounts owing to the Company under any swap agreement result in a reduction of the obligations referred to in clause (b).

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

the amounts for such period of Consolidated Net Income,

plus

the sum, without duplication, of the amounts for such period of the following expenses (or charges) to the extent deducted from Consolidated Net Income during such period:

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

minus

the sum, without duplication of the amounts for such period of the following items to the extent increasing Consolidated Net Income during such period:

i) Other non-Cash items increasing Consolidated Net Income for such period (excluding any such non-Cash item to the extent it represents the reversal of an accrual or reserve for potential Cash item in any prior period), plus
ii) Interest income, plus
iii) Non-cash gains resulting from the mark-to-market exposure of outstanding swaps and unrealized foreign exchange exposure.

The Company also has a financial covenant for its General and Administrative costs ("G&A costs") that it shall not exceed 105% of the G&A costs cap of $2.0 million per annum as at December 31, 2017, and escalating to $2.5 million per annum in 2018 for each year thereafter.

There are no financial covenants in effect for the period ended September 30, 2017.

d) Capital Management

The Company manages its capital with the following objectives:

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

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

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

## Commitments

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

On April 27, 2017, the Company issued 4,048,200 Canadian Development Expense flow-through shares at $0.28 per share for gross proceeds of $1,133,496 which has a commitment to be expended, pursuant to the provisions of the *Income Tax Act* (Canada), by December 31, 2017. As at September 30, 2017, the Company has fully expended its commitment.

As at September 30, 2017, the gross balance of the Term Loan was $12,470,000 (USD$10,000,000), exclusive of the debt issuance costs. The Term Loan matures on September 15, 2022.

| | **2017** | 2018 | 2019 | 2020 | 2021 | Thereafter | Total |
|---|---|---|---|---|---|---|---|
| Office Rental | $ **48,365** | $ 80,609 | $ - | $ - | $ - | $ - | $ 128,974 |
| Term Loan | **-** | - | - | - | - | 12,470,000 | 12,470,000 |
| | $ **48,365** | $ 80,609 | $ - | $ - | $ - | $ 12,470,000 | $ 12,598,974 |

## 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, 2016 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, 2016.

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

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

## Newly Adopted Accounting Standards

At the date of these financial statements the standards and interpretations listed below were issued but not yet effective. The adoption of these standards may result in future changes to existing accounting policies and disclosures. The Company is currently evaluating the impact that these standards will have on results of operations and financial position.

a) In May 2014, the IASB issued IFRS 15 "Revenue from Contracts with Customers," which replaces IAS 18 "Revenue," IAS 11 "Construction Contracts," and related interpretations. The standard is required to be adopted either retrospectively or using a modified transition approach for fiscal years beginning on or after January 1, 2018, with earlier adoption permitted. The Company has commenced the process of identifying and reviewing sales contracts with customers to determine the extent of the impact, if any, that this standard will have on the consolidated financial statements.

b) In July 2014, the IASB finalized the remaining elements of IFRS 9 – Financial Instruments, which includes new requirements for the classification and measurement of financial assets, amends the impairment model and outlines a new general hedge accounting standard. The mandatory effective date of IFRS 9 is for annual periods on or after January 1, 2018 and must be applied retrospectively with some exemptions. Early adoption is permitted. The Company is evaluating the impact of this standard on the consolidated financial statements and does not anticipate material changes to the valuation of its financial assets.

c) In January 2016, the IASB issued IFRS 16 Leases, which replaces IAS 17 Leases. For lessees applying IFRS 16, a single recognition and measurement model for leases would apply, with required recognition of assets and liabilities for most leases. The standard will come into effect for annual periods beginning on or after January 1, 2019, with earlier adoption permitted if the entity is also applying IFRS 15 Revenue from Contracts with Customers. The Company is currently identifying contracts that will be identified as leases and evaluating the impact of the standard on the consolidated financial statements.

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

## 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 September 30, 2017, the Company's financial instruments include accounts receivable, reclamation deposits, Term Loan, 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 | |
|---|---|---|
| | **September 30, 2017** | December 31, 2016 |
| Accounts receivable | | |
| Trade receivables | **$ 830,772** | $ 863,115 |
| Receivables from joint venture | **22,859** | 45,088 |
| Reclamation deposits | **115,535** | 115,535 |
| Total | **$ 969,166** | $ 1,023,738 |

The Company sells its oil production to two oil marketers 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 marketers.

**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 September 30, 2017, the Company had net debt of $14,426,091 (December 31, 2016 - $11,827,170), which includes its Term Loan of $12,470,000 (December 31, 2016 - $11,247,537 bank indebtedness). Effective September 15, 2017, the Company repaid and terminated its $12.5 million credit facility with with Alberta Treasury Branches. The Company funds its operations through production revenue and its Term Loan.

**Market risk**

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

*Interest rate risk*

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. Borrowings under the Company's Term Loan are subject to variable interest rates. A one percent change in interest rates would have a $150,000 annual effect on net income (loss) and comprehensive income (loss).

*Foreign currency risk*

The Company's functional and reporting currency is Canadian dollars. The Company does not sell or transact in any foreign currency; except i) the Company's commodity prices are largely denominated in USD, and as a result the prices that the Company receives are affected by fluctuations in the exchange rates between the USD and the Canadian dollar. The exchange rate effect cannot be quantified, but generally an increase in the value of the Canadian dollar compared to the USD will reduce the prices received by the Company for its crude oil and natural gas sales. The Company does have foreign exchange rate swaps in place as further disclosed within this MD&A and the interim condensed financial statements for the three and nine months ended September 30, 2017; and ii) the Company's Term Loan is denominated in USD and, as a result, the amount that the Company will be obligated to repay at the term of the loan will be affected by fluctuations in the exchange rate between the USD and the Canadian dollar at that time. A 100 basis points change in the foreign exchange rate would have a $100,000 effect on net loss and comprehensive loss.

*Commodity price risk*

Commodity prices for petroleum and natural gas are impacted by global economic events that dictate the levels of supply and demand, as well as the relationship between the Canadian dollar and the USD. Significant changes in commodity prices may materially impact the Company's funds flow from operations, and ability to raise capital. The Company has derivative commodity contracts in place as further disclosed within this MD&A and the interim condensed financial statements for the three and nine months ended September 30, 2017.

*Other price risk*

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

## Non-IFRS Measures

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

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

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

| | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| | **2017** | 2016 | **2017** | 2016 |
| Cash provided by operating activities | **$ 955,786** | $ 244,550 | **$ 1,748,849** | $ (168,637) |
| Less: Change in non-cash working capital | **297,947** | (100,457) | **(12,399)** | (426,024) |
| Funds flow from operations | **$ 657,840** | $ 345,007 | **$ 1,761,249** | $ 257,387 |
| Per share, basic and diluted | **$ 0.01** | $ 0.00 | **$ 0.02** | $ 0.00 |

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

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

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

The following table outlines the Company calculation of net debt:

| | As at | |
|---|---|---|
| | **September 30, 2017** | December 31, 2016 |
| Current assets[1] | **$ 1,602,550** | $ 1,078,020 |
| Current liabilities[2] | **(3,558,641)** | (1,657,652) |
| Bank indebtedness | **-** | (11,247,537) |
| Term Loan[3] | **(12,470,000)** | - |
| Net debt | **$ (14,426,091)** | $ (11,827,170) |

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

## Boe Conversion

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

## Forward-Looking Statements

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

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

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

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