IRONHORSE OIL & GAS INC.
MANAGEMENT'S DISCUSSION & ANALYSIS

This management's discussion and analysis ("MD&A") for Ironhorse Oil and Gas Inc. ("Ironhorse" or the "Company" or "we" or "our"), dated August 23, 2016 should be read in conjunction with the condensed financial statements for the three and six months ended June 30, 2016 and June 30, 2015 and the financial statements for the years ended December 31, 2015 and December 31, 2014.

The interim condensed financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP") which comprises International Financial Reporting Standards ("IFRS") as applicable for the interim financial statements, including International Accounting Standards ("IAS") 34, "Interim Financial Reporting".

This MD&A contains Non-GAAP measures and forward-looking statements. Readers are cautioned that the MD&A should be read in conjunction with Ironhorse's disclosure under the Advisory heading included at the end of this MD&A. Additional information relating to Ironhorse, can be found on SEDAR at www.sedar.com or on the Company's website at www.ihorse.ca.

2016 OVERVIEW

Ironhorse is engaged in the development and production of petroleum and natural gas reserves in western Canada. Ironhorse's shares are listed on the TSX Venture Exchange under the symbol IOG.

On January 19, 2016 the operator of the Nisku L2L Pool shut-in production from the Pembina wells because continued production was uneconomic under the commodity price environment. The Company believed that, with the downward pressure on commodity prices, the temporary shut-in of the Pembina production was a prudent decision to preserve the value of Ironhorse's oil and natural gas reserves. Subsequent to Q1 2016, benchmark Canadian light sweet oil prices ascended to average over $55/bbl for the three months of May to July.

The Company continues to have a positive working capital position which has decreased to $2.7 million at June 30, 2016 compared with $2.9 million at December 31, 2015. With the Pembina wells shut in since mid-January, production has been limited to 10 boe/d with operating netbacks of $3,000 for the current quarter as compared to a netback of $15,000 and 67 boe/d for the prior quarter ended March 31, 2016. Negative cash flows from operations improved 28% to $94,000 for Q2 2016 compared to negative cash flows of $131,000 for Q1 2016 which included $55,000 in take-over bid costs reported.

The Company realized a net loss of $69,000 for Q2 2016 compared to $144,000 for Q1 2016. The reduced loss for the current quarter is primarily a result of lower general and administrative and depletion costs recorded as total netbacks did not change significantly despite 85% lower production compared to Q1 2016.

OUTLOOK

On July 19, 2016 the Operator of the Pembina L2L pool (the "Pool") restarted Pool production with both the 09-05 and 14-05 wells brought back on stream by the end of July. Combined production from the Pool is currently averaging 1670 boe/d gross (261 boe/d net). August and September net production for Q3 2016 is projected to average in the range of 219 boe/d to 235 boe/d with no third party facility downtime or pipeline restrictions anticipated. Q3 2016 cash flows from operations should return to being positive.

Lawsuit – Statement of Claim Filed and Counter claim

On February 23, 2016, the Company and Grizzly Resources Ltd. ("GRL"), the operator of the Pembina wells, jointly filed a Statement of Claim in the Court of Queen's Bench of Alberta against Sinopec. The Company and GRL are seeking damages against Sinopec for misrepresentation and breach of contract.
On April 15 2016 Sinopec filed a Statement of Defense, as well as a Counterclaim, in response to the Company's and GRL's Statement of Claim. On May 24, 2016 Ironhorse and GRL filed a Statement of Defense to the Sinopec Counterclaim.

UNSOLICITED TAKE-OVER BID

On November 4, 2015, an unsolicited all cash take-over bid (the "Offer") was commenced by 1927297 Alberta Ltd. (the "Offeror"), a corporation wholly-owned by Timmerman Trust, to acquire the outstanding common shares of Ironhorse for $0.17 per share which expired on February 5, 2016. The Offeror did not take up any shares deposited under the Offer. The Company has incurred approximately $325,000 as at July 31, 2016 in total general and administrative costs related to the take-over-bid.

SELECTED QUARTERLY INFORMATION	For the three months ended		
($ thousands except per share amounts)	**June 30 2016**	March 31 2016	June 30 2015
Petroleum and natural gas revenues(1)	**16**	162	1,262
Funds from operations(2)	**(94)**	(131)	401
Net loss	**(69)**	(144)	(634)
Net loss per share-basic & diluted	**-**	(0.01)	(0.02)
Capital expenditures(3)	**-**	(1)	3
Total assets	**14,010**	14,255	20,966
Net working capital (debt)	**2,696**	2,785	3,041

(1) Petroleum and natural gas revenues are before royalty expense.
(2) Funds from operations and net debt are non-GAAP measures as defined in the Advisory section of the MD&A.
(3) Capital expenditures are before acquisitions and dispositions.

FINANCIAL AND OPERATING REVIEW

Production

	Three Months Ended June 30			Six Months Ended June 30		
	2016	2015	% Change	**2016**	2015	% Change
Light oil & NGL(bbl/d)	**1**	215	(100)	**23**	134	(83)
Natural gas (mcf/d)	**56**	233	(76)	**96**	202	(52)
Total (boe/d)	**10**	254	(96)	**39**	168	(77)
Volumes by product						
Oil & NGL	**10%**	85%	(88)	**59%**	80%	(26)
Natural gas	**90%**	15%	500	**41%**	20%	105

For the three months and six months ended June 30, 2016, Ironhorse's average daily light oil and NGL sales volumes were 1 bbls/d and 23 bbls/d, respectively. This represents a decrease of 100% and 83% compared to an average sales volume of 215 bbls/d and 134 bbls/d for the same periods of 2015.

The Pembina Nisku light oil property produced for just 18 days during the current year six month period as the property was shut-in on January 19, 2016 to preserve the value of the reserves until commodity prices recover. The shut-in resulted in lower production compared to 2015 which produced at restricted rates in Q1 2015 due to Sinopec's facility upgrades at the 13-2 battery and pipeline curtailments imposed by Trans Canada Pipelines and significantly higher production rates in Q2 2015 as sales volumes from the 2 Pembina wells averaged 1,530 boe/d gross (239 boe/d net).

Natural gas sales volumes for the three and six months ended June 30, 2016, were 56 mcf/d and 96 mcf/d respectively representing a decrease of 76% and 52% compared to an average sales volume of 233 mcf/d and 202 mcf/d for the same periods of 2015. This three and six month to date variance is due to the Company's decreased Pembina production as discussed above, offset by reduced production from the natural gas well at Balsam, Alberta. 2016 gas production is comprised of 21% from Pembina and 79% from Balsam.

Commodity Prices

	Three Months Ended June 30			Six Months Ended June 30		
	2016	2015	% Change	**2016**	2015	% Change
Average benchmark prices:						
WTI (US$/bbl)	**45.59**	57.94	(21)	**39.52**	53.29	(26)
Canadian Light Sweet ($/bbl)	**55.01**	68.88	(20)	**48.11**	61.08	(21)
AECO natural gas ($/mcf)(1)	**1.42**	2.67	(47)	**1.62**	2.71	(40)
Realized prices:						
Light oil & NGL ($/bbl)	**47.39**	61.80	(23)	**35.69**	58.57	(39)
Natural gas ($/mcf)	**2.30**	2.57	(11)	**1.75**	2.51	(30)
Total ($/boe)	**16.91**	54.70	(69)	**25.23**	49.81	(49)

(1) Represents the AECO Monthly (7a) Index

Revenues

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands)	**2016**	2015	% Change	**2016**	2015	% Change
Light oil & NGL	**4**	1,207	(100)	**147**	1,418	(90)
Natural gas	**12**	55	(78)	**31**	92	(66)
Total	**16**	1,262	(99)	**178**	1,510	(88)

Revenues and Commodity Prices

The Company's realized light oil and NGL price/bbl for the three and six months ended June 30, 2016, was 23% and 39% lower respectively compared to the same periods in 2015 and on par with the benchmark Canadian Light Sweet price percentage decreases. The Canadian Light Sweet oil benchmark price averaged $55.01/bbl for Q2 2016 increasing 33% compared to the Q1 2016 average of $41.22/bbl.

The Company's realized natural gas price/mcf for the three months and six months ended June 30, 2016 was 11% and 30% lower respectively compared to the same periods in 2015. The benchmark natural gas price decreased 47% and 40% for the three months and six months ended June 30, 2016 compared to the same periods in 2015. The Q1 2016 realized price of $2.30/mcf is significantly higher than the current quarter benchmark price due to prior period price and volume adjustments recorded during the quarter. The Company's realized natural gas and oil prices vary from benchmark prices due to transportation and location differentials.

Total sales revenue for the three months ended June 30, 2016 was $16,000 a 99% decrease from the $1,262,000 for the three months ended June 30, 2015. Revenues for the six months ended June 30, 2016 decreased by 88% from $1,510,000 to $178,000. This decrease in sales revenue for both the three months and six months ended

June 30, 2016 was a result of decreased sales volumes for both oil and natural gas, mainly attributable to the shut-in of the Pembina production in January 2016, and the downward trending commodity prices since late 2014.

Despite higher Q2 2016 oil and NGL benchmark pricing, realized revenues on a boe basis declined 36% to $16.91/boe during the quarter compared to $26.50/boe for Q1 2016. This quarter over quarter decline is a result of having a 90% gas sales production weighting as benchmark gas prices trended 23% lower during the current quarter and had a higher impact on revenues compared to Q1 2016.

Royalties

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands except per boe)	**2016**	2015	% Change	**2016**	2015	% Change
Oil & NGL	**3**	360	(99)	**65**	448	(85)
Natural gas	**(57)**	11	(618)	**(50)**	24	(308)
Royalties	**(54)**	371	(115)	**15**	472	(97)
Royalties %	**(338)**	29	(1266)	**8**	31	(74)
Royalties per boe	**(57.30)**	16.07	(457)	**2.20**	15.56	(86)

Royalties represent charges against production or revenue by governments and mineral right owners. From period to period royalties vary due to changes in the production mix, production rates and sales prices; the components of which are subject to different royalty rates.

For the three months ended June 30, 2016, royalties decreased 115% from $371,000 in the comparable period in 2015 to $54,000. The recovery in 2016 is related to $59,000 of gas cost allowance ("GCA") and custom processing fee credits received related to natural gas crown royalties previously paid. Royalties as a percentage of revenues decreased to (338%) for the three months ended June 30, 2016 compared to 29% in the comparable period in 2015.

Royalties as a percentage of revenues decreased 74% to 8% for the six months ended June 30, 2016 compared to the same period in 2015. This significant 2016 decrease in royalties incurred and on a percentage basis is due to the recovery discussed above and the Pembina area being shut-in for most of the current year.

Operating Expenses

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands except per boe)	**2016**	2015	% Change	**2016**	2015	% Change
Operating expenses	**67**	380	(82)	**145**	502	(71)
Operating expenses ($/boe)	**71.51**	16.44	335	**20.53**	16.55	24

Operating expenses were $67,000 or $71.51/boe, for the three months ended June 30, 2016 compared to $380,000 or $16.44/boe for the comparable period in 2015 representing a decrease of 82% and 335% increase respectively. For the six months ended June 30, 2016 operating costs decreased by 71% to $145,000 or $20.53/boe compared to $502,000 or $16.55/boe compared to the same period in 2015.

The decrease in 2016 operating expenses incurred is due to lower Pembina production levels in 2016 compared to 2015. The significant increase in Q2 2016 operating costs of over 300% on a boe basis is mainly attributed to recently invoiced and approved retroactive third party 2014 and 2015 handling fees related to the Pembina area.

Operating Netbacks

	Three Months Ended June 30			Six Months Ended June 30		
	2016	2015	% Change	**2016**	2015	% Change
Oil & NGL ($/bbl)	**47.39**	61.80	(23)	**35.69**	58.57	(39)
Natural gas ($/mcf)	**2.30**	2.57	(11)	**1.75**	2.51	(30)
Revenues ($/boe)	**16.91**	54.70	(69)	**25.23**	49.81	(49)
Royalties ($/boe)	**57.30**	(16.07)	(457)	**(2.20)**	(15.56)	(86)
Operating expenses ($/boe)	**(71.51)**	(16.44)	335	**(20.53)**	(16.55)	24
Operating netback ($/boe)	**2.70**	22.19	(88)	**2.50**	17.70	(86)

Ironhorse's operating netback per boe for the three months ended June 30, 2016 decreased by 88% from the three months ended June 30, 2015. For the six months ended June 30, 2016, operating netback was $2.50/boe compared to $17.70/boe in the same period in 2015 representing an 86% decrease. Realized oil and liquids prices decreased 23% and 39% for the three and six months ended June 30, 2016 respectively as a result of commodity price declines.

The decreased netback in 2016 compared to 2015 is the result of continued lower oil and gas prices, higher operating costs reported at Pembina during Q2 and partially offset by lower royalties attributed to GCA credits recorded and lower royalties resulting from Pembina being shut-in for 90% of the first half of the year.

General and Administrative (G&A) Expense and Share-based Compensation

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands except per boe)	**2016**	2015	% Change	**2016**	2015	% Change
G&A expense	**102**	114	(11)	**252**	211	19
G&A expense ($/boe)	**109.36**	4.94	2114	**35.83**	6.96	415

G&A expense for the three months ended June 30, 2016 decreased 11% to $102,000 from $114,000 for the three months ended June 30, 2015. The decrease was primarily due to Q1 and Q2 director and special committee fees being recorded in the Q2 2015 period versus only directors fees in 2016, partially offset by higher legal costs incurred in Q2 2016 related to the Sinopec lawsuit.

G&A expenses for the six months ended June 30, 2016 increased 19% to $252,000 from $211,000 for the same period in 2015. The increase is attributed to $55,000 in costs incurred during Q1 related to the unsolicited take-over bid offer as previously disclosed during Q4 2015. The Company has incurred $325,000 in total G&A costs related to the take-over bid as at July 31, 2016

G&A expense per boe for the three and six months ended June 30, 2016 increased 2114% to $109.36/boe and 415% to $35.83/boe compared to $4.94/boe and $6.96/boe for the 2015 comparable periods. The substantial increase based on a barrel equivalent basis is due to lower production in 2016 compared to 2015.

Share-based compensation was $nil for the three and six months ended June 30, 2016 and comparable 2015 periods as a result of no stock options being granted in the past two years and the expiration and forfeiture of options during 2014 and 2015.

Finance (income) and Expense

($ thousands except per boe)	Three Months Ended June 30			Six Months Ended June 30		
	2016	2015	% Change	**2016**	2015	% Change
Interest (income)	**(5)**	(4)	25	**(9)**	(8)	13
Accretion	**-**	1	(100)	**1**	2	(50)
Finance (income)	**(5)**	(3)	67	**(8)**	(6)	33
Finance (income) ($/boe)	**(4.73)**	(0.14)	3279	**(1.02)**	(0.20)	410

For the three and six months ended June 30, 2016 the Company received $5,000 and $9,000 in interest income compared to $4,000 and $8,000 in the comparative 2015 periods. Interest income is dependent on the level of funds held on deposit. During the first six months in both 2016 and 2015, the Company did not have bank debt and received interest on its cash balance and deposits.

Accretion is the increase or decrease, in the reporting period, in the present value of the Company's decommissioning liabilities that are estimated based on current costs, inflated at a rate of 2% and discounted using a risk free interest factor of between 0.6% and 1.7%.

Depletion and amortization

($ thousands except per boe)	Three Months Ended June 30			Six Months Ended June 30		
	2016	2015	% Change	**2016**	2015	% Change
Depletion and amortization	**-**	521	(100)	**66**	663	(90)
Depletion and amortization ($/boe)	**-**	22.59	(100)	**9.37**	21.88	(57)

Depletion and amortization expense was $nil for the three months ended June 30, 2016 as compared to $521,000 or $22.59/boe in the same period in 2015 and $66,000 or $9.37/boe for the six months ended June 30, 2016 compared to $663,000 or $21.88/boe for the same period in 2015. In both cases, the decrease in depletion is due to lower production as the Pembina wells were shut-in January 19, 2016 onward and the depletion base is $nil for the Balsam area minor CGU resulting from the impairment recorded in Q4 2015.

Impairment

($ thousands except per boe)	Three Months Ended June 30			Six Months Ended June 30		
	2016	2015	% Change	**2016**	2015	% Change
Impairment	**-**	608	(100)	**-**	609	(100)
Impairment ($/boe)	**-**	26.37	(100)	**-**	20.09	(100)

An impairment expense is recognized for the amount by which the carrying amount exceeds the recoverable amount. Impairment expense is reversed when there has been a subsequent increase in the recoverable amount, but only to the extent of what the carrying amount would have been, had no impairment been recognized.

During the three month period ended June 30, 2015, the Company recognized an impairment charge of $609,000 to its Pembina area CGU as a result of higher than anticipated operating costs, lower realized sales revenues and lower production as compared to the 2014 yearend reserve report forecast. The higher operating costs were mainly attributed to the blending fees and handling costs related to the high H_2S content of the solution gas produced.

Income Taxes

During the second quarter of 2015, the Alberta government enacted legislation increasing the provincial corporate income tax rate from 10% to 12% effective July 1, 2015. As a result of this income tax rate increase, the Company's deferred income tax liability was increased by $87,000 in second quarter of 2015.

Capital Expenditures

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands)	**2016**	2015	% Change	**2016**	2015	% Change
Drilling and completions	**-**	3	(100)	**-**	18	(100)
Facilities	**-**	-	-	**(1)**	5	(120)
Capital expenditures	**-**	3	(100)	**(1)**	23	(104)

Capital expenditures were nominal with a credit of $1,000 recorded for the six months ended June 30, 2016 compared to $23,000 for six months ended June 30, 2015. Capital expenditures for the current year are related to minor facility cost adjustments at Pembina.

Capital Commitments

The Company has commenced abandonment work on the Company's operated Dawson, Alberta property and expects to incur expenditures during the remainder of 2016.

Financial Resources and Liquidity

Ironhorse's strategy is to maintain a capital structure which will sustain the Company while determining strategic alternatives available to maximize value for the shareholders. This strategy may consider future investments and acquisition opportunities, the amount of credit that may be obtainable from a lender, the availability of other sources of debt, the sale of assets, adjustments to the current capital expenditures program, and issuance of new shareholder capital. The Company's approach to managing liquidity risk is by preparing and monitoring capital and operating budgets, coordinating and authorizing project expenditures and updating when required as conditions change. The Company plans to meet its obligations when due through its available cash resources and may seek potential credit facilities in the future.

The Company's shareholders' capital is not subject to external restrictions and it does not have any credit facilities. The approach to capital management during the period has not changed from the prior reporting period and the Company's net working capital is as follows:

($ thousands) **As at**	**June 30, 2016**	December 31, 2015
Current assets	**2,791**	4,026
Current liabilities	**(95)**	(1,111)
Net working capital	**2,696**	2,915

Shareholders' Equity

At June 30, 2016 the number of common shares issued and outstanding was 27,885,824 (December 31, 2015 - 27,885,824). As at August 23, 2016 the Company had 27,885,824 common shares and 105,000 stock options issued and outstanding under its stock option plan.

During the six months ended June 30, 2016 there were no option grants and 20,000 options that were forfeited.

Transactions with Related Parties

The Company, Grizzly Resources Ltd. (“GRL”) and Copper Island Resources Ltd. (“CIRL”) are considered related by virtue of common management. The Company and GRL are also significant joint venture partners in Ironhorse’s operating areas. The Company has entered into a management contract with GRL to provide technical and administrative services.

The Directors of the Company approved director fees and special committee fee compensation for non-management board members commencing in 2015. One of the board members is also a board member of GRL and was paid director fee compensation in 2015 and in 2016.

Joint venture transactions

The nature of the joint venture transactions between GRL and Ironhorse are governed by industry standard joint operating agreements. GRL provides monthly joint interest billings to the Company which include capital expenditures, operating costs, revenues and royalty costs related to joint venture lands. Throughout the year, GRL provides the Company’s Board of Directors with information related to upcoming issues related to these joint properties to seek approval for any significant capital requirements or approval for major funding requirements that would be required by Ironhorse. The common joint venture property between the two companies is the Pembina area of Alberta.

Management fee transactions

GRL charges Ironhorse a monthly management fee for services required to manage the Company’s day to day operations. The fee is based on an estimate of accounting services, senior management services, information technology costs, reception, office rent and other general office administration. The monthly management fee for the six months ended June 30, 2016 was $15,000 per month (June 30, 2015 - $15,000). The management agreement is reviewed annually to account for any changes in the Company’s operating assets.

For a more detailed discussion on related party transactions see note 8 of the accompanying condensed interim financial statements.

RISK FACTORS

General

Many risks are discussed below, but these risk factors should not be construed as exhaustive. There are numerous factors, both known and unknown, that could cause actual results or events to differ materially from expected results.

Depletion of reserves

Oil and natural gas operations involve many risks that, even with a combination of experience, knowledge and careful evaluation, the Company may not be able to overcome. The long-term commercial success of the Company depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves the Company may have at any particular time and the production there from will decline over time as such existing reserves are exploited. A future increase in the Company's reserves will depend not only on the Company’s ability to explore and develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. No assurance can be given that further commercial quantities of oil and natural gas will be discovered or acquired by the Company.

Financing and capital requirement

The Company's principal risks include finding and developing economic hydrocarbon reserves efficiently and being able to fund the capital program. The Corporation's need for capital is both short-term and long-term in nature. Short-term working capital will be required to finance accounts receivable, drilling deposits and other similar short-term assets, while the acquisition and development of oil and natural gas properties requires large amounts of long-term capital. The Company anticipates that future capital requirements will be funded through a combination of funds from operations, sale of existing assets and issuance of debt and/or equity financing. There is no assurance that debt and equity financing will be available on terms acceptable to the Company to meet its capital requirements. If any components of the Company's business plan are missing, the Company may not be able to execute the entire business plan.

Changes in Government Royalty Legislation

Provincial programs related to the oil and natural gas industry may change in a manner that adversely impacts shareholders. Ironhorse currently operates in Alberta and future amendments to royalty programs could result in a reduction of cash flows.

Regulatory Approval Risks

Before proceeding with most major development projects, Ironhorse must obtain regulatory approvals and maintain these approvals through to project completion. The regulatory approval process involves stakeholder consultation, environmental impact assessments and public hearings, among other factors. Failure to obtain regulatory approvals, or failure to obtain them on a timely basis, could result in delays, abandonment, or restructuring of projects and increased costs, all of which could negatively impact future earnings and cash flow. Failure to maintain approvals, licenses, permits and authorizations in good standing could result in the imposition of fines, production limitations or suspension orders.

Reliance on Partners

Ironhorse is dependent on other working interest partners to fund their contractual share of the capital expenditures. If these partners are unable to fund their contractual share of, or do not approve the capital expenditures, the partners may seek to defer programs, resulting in delays of portion of development of Ironhorse's programs, or the partners may default such that projects may be delayed and/or Ironhorse may be partially or totally liable for their share.

Environmental

The oil and natural gas industry is subject to environmental regulation pursuant to local, provincial and federal legislation. A breach of such legislation may result in the imposition of fines or issuance of clean up orders in respect to Ironhorse or its working interests. Such legislation may be changed to impose higher standards and potentially more costly obligations on Ironhorse. Furthermore, management believes that the federal political parties appear to favour new programs for environmental laws and regulations, particularly in relation to the reduction of emissions, and there is no assurance that any such programs, laws or regulations, if proposed an enacted, will not contain emission reduction targets which the Company cannot meet.

ACCOUNTING POLICIES AND ESTIMATES

Critical Accounting Estimates

We make judgements, estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Although these estimates are based on management's best knowledge of the amount, event or actions, actual results ultimately may differ from those estimates. The Company's financial and operating results incorporate estimates including:

- Estimated revenues, royalties, operating expenses on production;
- Estimated capital expenditures on projects that are in progress;
- Estimated depletion, depreciation, amortization expenses that are based on estimates of oil and gas proved and probable reserves that the Company expects to recover in the future;
- Estimated value of decommissioning liabilities that are dependent on estimates of future costs and timing of expenditures;
- Estimated future recoverable value of development and production assets within PP&E and exploration and evaluation assets;
- Estimated deferred income tax assets and liabilities based on current tax interpretations, regulations and legislation that is subject to change;
- Estimated loss probable based on judgement and interpretation of laws and regulations.

The recoverable amounts of PP&E asset by area have been determined as the greater of the asset by area's value-in-use and fair value less costs to sell. These calculations require the use of estimates and assumptions and are subject to changes as new information becomes available including information on future commodity prices, expected production volumes, quantity of reserves and discount rates, as well as, future development and operating costs. Changes in the following assumptions used in determining the recoverable amount could affect the carrying value of the related asset.

- Reserves: Assumptions that are valid at the time of reserve estimation may change significantly when new information becomes available. Changes in forward price estimates, production costs or recovery rates may change the economic status of reserves and may ultimately result in reserves being restated.

- Oil and natural gas prices: Forward price estimates of the oil and natural gas prices are used in the cash flow model. Commodity prices have fluctuated widely in recent years due to global and regional factors including supply and demand fundamentals, inventory levels, exchange rates, weather, economic and geopolitical factors.

- Discount rate: The discount rate used to calculate the net present value of cash flows is based on estimates of an approximate industry peer group weighted average cost of capital. Changes in the general economic environment could result in significant changes to this estimate.

New and Future Accounting Pronouncements

IFRS 9- Financial Instruments

The IASB is replacing International Accounting Standards ("IAS") 39, "Financial Instruments: Recognition and Measurement" with IFRS 9, "Financial Instruments". For financial assets, IFRS 9 uses a single approach to determine whether a financial asset is measured at amortized cost or fair value, and replaces the multiple rules in IAS 39. IFRS 9 is effective for annual periods beginning on or after January 1, 2018.

IFRS 11- Joint Arrangements

IFRS 11 Joint arrangements has been amended to require that the relevant principles from IFRS 3 Business combinations be applied when an organization acquires an initial or additional interest in a joint operation and the activities of the joint operation constitute a business as defined in IFRS 3. IFRS 1 is effective for annual periods beginning on or after January 1, 2016.

Amendment of IFRS 15 - Revenue Recognition

The IASB has issued IFRS 15 Revenue from contracts with customers which will replace the current revenue guidance on revenue and construction contracts. The expectation is that IFRS 15 provides a recognition standard that can be applied consistently across various transactions, industries and capital markets. The standard specifies the five steps that an organization would apply to recognize revenue; identifying the contract with the customer, identifying the performance obligations to transfer distinct goods or services within the contract, determining the transaction price, allocating the transaction price to each separate performance obligation on the basis of relative stand-alone selling prices, and recognizing revenue when or as the performance obligation is satisfied. An organization will be considered to have satisfied a performance obligation by transferring a promised good or service to a customer with a transfer being defined in terms of when the customer obtains control of the promised good or service. IFRS 15 is effective for annual periods beginning on or after January 1, 2018.

ADVISORY SECTION

Non-GAAP Measures

The MD&A contains terms commonly used in the oil and gas industry, such as operating netbacks ("netbacks"), funds from operations and net debt. These terms are not defined by the financial measures used by the Company to prepare its financial statements and are referred to herein as non-GAAP measures. These non-GAAP measures should not be considered an alternative to, or more meaningful than, other measures of financial performance calculated in accordance with GAAP. Management believes that in addition to net earnings (loss), netbacks, funds from operations and net debt are useful financial measurement which assist in demonstrating the Company's ability to make interest payments, fund capital expenditures necessary for future growth or repay debt. The non-GAAP measures presented may not be comparable to that report by other companies.

Netback

Ironhorse uses netback as a key performance indicator. Netback does not have a standardized meaning prescribed by Canadian GAAP and therefore may not be comparable with the calculation of similar measures by other companies. Netback is calculated by deducting royalties and operating expenses from petroleum and natural gas revenues.

Funds from Operations

Funds from Operations is not a recognized performance measure under GAAP and does not have a standardized meaning prescribed by GAAP. Funds from operations include cash flow from operating activities and is calculated before changes in non-cash working capital and decommissioning liabilities settled. The most comparable measure calculated in accordance with GAAP is cash flow from operating activities. The Company considers it a key measure as it demonstrates the ability of the Company to generate the funds necessary to finance future capital investments and repay debt.

The following table reconciles cash flow from operating activities to funds from operations which is used in the MD&A:

($ thousands)	**Q2 2016**	Q1 2016	Q2 2015
Cash flow from operating activities	**(332)**	(761)	200
Decommissioning expenditures (recovery)	**(5)**	-	-
Changes in non-cash working capital	**243**	630	201
Funds from operations	**(94)**	(131)	401

Net Debt

Net debt is not a recognized performance measure under GAAP and does not have a standardized meaning prescribed by GAAP. Net debt is calculated as debt and current liabilities less current assets as they appear on the balance sheet and excludes current unrealized amounts pertaining to risk management contracts and assets held for sale and associated liabilities held for sale.

Forward-Looking Information

Certain information regarding Ironhorse set forth in this document, including management's assessment of the Company's future plans and operations, contains forward-looking statements that involve substantial known and unknown risks and uncertainties. These forward-looking statements are subject to numerous risks and uncertainties, some of which are beyond Ironhorse's control. These risks include, but are not limited to, operational risks in development, exploration, production and start-up activities; delays and changes in plans with respect to exploration or development projects or capital expenditures; the uncertainty of reserve estimates; the uncertainly of estimates and projections relating to production, costs and expenses, and environmental risks, risks associated with the impact of industry conditions, volatility of commodity prices, currency fluctuations, competition from other producers, ability to access capital from internal and external sources. Ironhorse's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do so, what impact it would have on Ironhorse. Words such as “may”, “will”, “should”, “could”, “anticipate”, “believe”, “expect”, “intend”, “plan”, “potential”, “continue”, and similar expressions have been used to identify these forward-looking statements.
The forward-looking information contained in this MD&A are as of the date of the MD&A and Ironhorse assumes no obligation to update or revise any forward-looking information to reflect new events or circumstances, except as required by applicable laws.

BOE Conversion

In this document, certain natural gas volumes have been converted to barrels of oil equivalent ("boe") on the basis of one barrel (“bbl”) to six thousand cubic feet (“mcf”), unless otherwise stated. A conversion ratio of one bbl to six mcf is based on an energy equivalent conversion applicable at the burner tip and does not represent a value equivalency at the wellhead. Additionally, given the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion ratio of 6:1 may be misleading as an indication of value.

QUARTERLY FINANCIAL INFORMATION

The Company’s operating results over the past eight quarters reflect the ongoing shift in focus as Ironhorse increases the oil weighting of its reserves and restructures its balance sheet.

($ thousands except per unit and share data)	Q2 2016	Q1 2016	Q4 2015	Q3 2015	Q2 2015	Q1 2015	Q4 2014	Q3 2014
Volumes								
Natural gas (mcf/d)	56	137	202	162	233	171	150	130
Oil & NGL (bbl/d)	1	44	197	189	215	52	77	64
Total (boe/d)	10	67	231	216	254	81	102	86
Revenues (1)	16	162	892	941	1,262	248	545	593
Funds from operations(2)	(94)	(131)	(144)	39	401	(68)	123	358
Per share-basic and diluted	-	(0.01)	(0.01)	-	0.01	-	0.01	0.01
Net income (loss)	(69)	(144)	(2,076)	(2,850)	(634)	(159)	(331)	141
Per share-basic and diluted	-	(0.01)	(0.07)	(0.10)	(0.02)	(0.01)	(0.01)	0.01
Weighted average shares								
Basic and diluted	27,886	27,886	27,886	27,886	27,886	27,886	27,886	27,886

(1) Revenues are before royalties
(2) Non-GAAP measures are defined in the Advisory section within this MD&A.