Management's Discussion & Analysis ("MD&A")

For the year ended December 31, 2017

Dated: March 20, 2018

Management's Discussion and Analysis

Management's discussion and analysis ("**MD&A**") is the explanation by the Management of Iron Bridge Resources Inc. (the "**Company**" or "**IBR**") of its consolidated financial performance for the years covered by the consolidated financial statements along with an analysis of IBR's financial position. The following commentary relates to and should be read in conjunction with the audited consolidated financial statements of the Company for the years ended December 31, 2017 and 2016. All figures provided herein are reported in Canadian dollars unless otherwise stated. Within this MD&A, consolidated financial and operating information for the year ended December 31, 2017 ("**Year 2017**") is compared to the prior year ended December 31, 2016 ("**Year 2016**") and for the three month periods then ended.

The Company's audited consolidated financial statements for the years ended December 31, 2017 and 2016, in addition to other disclosure documents, are available on the *System for Electronic Document Analysis and Retrieval* ("**SEDAR**") at www.sedar.com and IBR's company website at www.ironbridgeres.com.

This MD&A contains non-GAAP measures which are not prescribed by International Financial Reporting Standards ("**IFRS**") and therefore may not be comparable with the calculating of similar measures presented by other companies. Additionally, statements throughout this MD&A that are not historical facts may be considered "forward-looking statements". Readers should read the advisories under the headings "*Non-GAAP Measures*" and "*Forward-Looking Statements*" included at the end of the MD&A.

This MD&A includes information up to and including March 20, 2018.

Business Overview and Developments

Iron Bridge Resources Inc. is an independent, Alberta-based crude oil and natural gas company actively engaged in the exploration for, development and production of crude oil, natural gas and NGLs reserves from the Montney formation at Elmworth in West Central Alberta in the Western Canadian Sedimentary Basin. IBR is incorporated under the laws of Alberta and its common shares are publicly listed and traded on the Toronto Stock Exchange ("**TSX**") under the trading symbol "IBR". The Company's head office is located in Calgary, Alberta at 1200, 500 - 4th Avenue S.W., T2P 2V6. As of March 19, 2018, IBR's market capitalization was approximately $85.2 million. Market capitalization is calculated by applying a point-in-time closing share trading price to the number of common shares outstanding.

Strategic Asset Disposition

On October 17, 2017, the Company closed the strategic asset disposition (the "**Disposition Transaction**") to Tangle Creek Energy Ltd. ("**Tangle Creek**"), a private oil and gas company, pursuant to which Tangle Creek acquired all of the Company's crude oil and natural gas interests in the Waskahigan, Grizzly, Kaybob, Gilby and Pine Creek areas of West Central Alberta in addition to other minor Alberta properties (collectively, the "**Assets**"). Consideration received by the Company totaled approximately $77.0 million, net of closing adjustments and related costs, comprised of approximately $68.0 million in cash and approximately 13.85 million Tangle Creek common shares (having a value of $9.0 million based upon the issue price of Tangle Creek's most recent equity financing completed). The privately-traded Tangle Creek common shares have been classified as an *available-for-sale financial asset*. Prior to the closing of the Disposition Transaction, the Assets were classified as *assets held for sale* and measured at the lower of their carrying amount and fair value less costs to sell resulting in an impairment loss of $102.5 million. Upon the closing of the Disposition Transaction, the Company recognized a loss on disposition of $0.3 million. The effective date of the Transaction was June 1, 2017. The Disposition Transaction was approved by overwhelming majority (over 99%) by the holders of common shares of the Company at a special meeting of shareholders held on October 13, 2017.

The Company's reported fourth quarter 2017 and Year 2017 results include operational and financial contribution from the disposed Assets up to the date of closing of October 17, 2017, when control transferred.

The Disposition Transaction strategically transformed the Company to a geographically and geologically-focused Montney producer at Elmworth in West Central Alberta. IBR holds a large land base at Elmworth consisting of 84 (83.5 net) sections (53,440 net acres) of operated Montney acreage, with substantial resource potential. Delineation and development of the Company's Elmworth assets will focus on extended reach horizontals with increased frac and proppant intensity. These technical improvements coupled with operational efficiencies in spud-to-on-stream cycle times, emulsion management and infrastructure optimization is expected to provide the key to unlocking the vast potential of the Elmworth Montney fairway.

New Management Team and Private Placement

On July 26, 2017, the Company announced a series of appointments that resulted in the formation of a new executive management team. The new team consists of Rob Colcleugh as Chief Executive Officer, Tim Krysak as President and Chief Operating Officer, Jeremy Smith as Vice President Drilling Operations, Gregg Nixon as Vice President Completions and Production, Zoran Jankovic as Vice President Exploration and Dean Bernhard, who continues as the Company's Vice President Finance and Chief Financial Officer (collectively the "**New Management Team**"). The appointments of the new executive members were effective as of August 1, 2017. Each member of the New Management Team has demonstrated a historical track record of operational excellence and long-term shareholder value generation in highly successful Canadian energy companies.

The incoming new executive members of the appointed New Management Team and members of the Board of Directors participated in a private placement in the third quarter of 2017 resulting in the issuance of 5.35 million units of the Company ("**Units**") at a purchase price of $0.60 per Unit for gross proceeds of approximately $3.2 million. Each Unit is comprised of one (1) common share ("**Common Share**") and one (1) common share purchase warrant ("**Warrant**"). Each Warrant entitles the holder to purchase one (1) Common Share at a price of $0.75 per share for a period of four (4) years following the date of issuance. The Warrants vest and become exercisable in equal tranches of one-third each upon the 20-day weighted average trading price of the Common Shares equaling or exceeding $0.75, $0.90 and $1.05, respectively.

Corporate Name Change

Subsequent to the Disposition Transaction, on November 22, 2017, the Company announced its corporate name change to "**Iron Bridge Resources Inc.**". Ironbridge Gorge is located in Shropshire, England and is recognized as one of the birthplaces of the Industrial Revolution. It was here in 1709 that Abraham Darby perfected the technique of producing pig iron in a blast furnace fueled by coke rather than coal allowing for much cheaper production of iron. The name reflects the Company's focus on innovation and cost efficiency in the unconventional resource revolution. The Company's common shares started trading on the TSX under the stock symbol "**IBR**" on November 27, 2017. No action is required by shareholders with respect to the corporate name change. Each existing share certificate reflecting the former name will continue to be a valid share certificate of the Company until such certificate is transferred, re-registered or otherwise exchanged through the Company's transfer agent.

Ante Creek Disposition

During the comparative 2016 fiscal period, on November 15, 2016, the Company closed the strategic disposition of its crude oil and natural gas interests in the Ante Creek area of West Central Alberta for cash consideration of $108.6 million, net of closing adjustments and related costs (the "**Ante Creek Disposition**"). The net cash proceeds received at the closing of the Ante Creek Disposition were used to eliminate outstanding bank indebtedness. The assets sold under the Ante Creek Disposition included reserves, land acreage and infrastructure facility and pipeline interests. The effective date of the Ante Creek Disposition was September 1, 2016.

Iron Chain Technology Corp.

On January 22, 2018, the Company announced the formation and launch of a wholly-owned cryptocurrency mining and hosting operation called Iron Chain Technology Corp. ("**ICT**"). ICT expects to begin operating its pilot cryptocurrency mining facility at Elmworth, Alberta in the second quarter of 2018. ICT is already currently mining with equipment sourced and assembled by technology professionals who have been engaged by the Company. ICT is providing hosting services for a limited amount of equipment from third-parties.

ICT's pilot cryptocurrency mining project will involve a very modest initial capital investment as a result of its ability to leverage existing infrastructure and excess power generation from IBR's Elmworth hydrocarbon processing battery, fired by IBR's clean burning natural gas production, to provide power to the mining control center. The pilot project currently has access to approximately 700 kW of very low cost power with the ability to expand that power generation capability.

Financial Highlights

The following table summarizes the Company's key quarterly financial results for the past eight (8) quarters and annual results for the past three (3) years:

	Quarterly Comparison								Annual Comparison		
	Q417	**Q317**	**Q217**	**Q117**	**Q416**	**Q316**	**Q216**	**Q116**	**Year 2017**	**Year 2016**	**Year 2015**
Production											
Natural gas *(Mcf/d)*	**10,369**	16,700	14,572	12,179	17,110	29,163	28,779	35,443	**13,459**	27,599	38,606
Oil and NGLs *(Bbls/d)*	**688**	1,227	1,127	1,177	1,801	3,259	3,628	4,510	**1,054**	3,295	5,592
Average boe/d *(6:1)*	**2,416**	4,010	3,556	3,207	4,652	8,119	8,425	10,418	**3,297**	7,895	12,026
Commodity Prices (1)											
Natural gas *($/Mcf)*	**2.03**	1.87	3.03	2.98	2.79	2.64	1.60	2.09	**2.46**	2.22	3.32
Oil and NGLs *($/Bbl)*	**58.07**	46.34	53.93	58.47	54.21	49.78	48.86	36.25	**53.64**	45.53	56.25
Oil equivalent *($/boe)*	**25.24**	21.94	29.52	32.76	31.24	29.47	26.51	22.80	**27.18**	26.76	36.82

	Quarterly Comparison								Annual Comparison		
	Q417	**Q317**	**Q217**	**Q117**	**Q416**	**Q316**	**Q216**	**Q116**	**Year 2017**	**Year 2016**	**Year 2015**
($000s, except per share amounts)											
Financial Results											
P&NG sales (1)	**5,610**	8,095	9,552	9,458	13,371	22,015	20,325	21,611	**32,715**	77,322	161,633
Net loss	**(3,637)**	(151,799)	(2,854)	(2,758)	(65,508)	(4,469)	(7,779)	(8,263)	**(161,048)**	(86,019)	(84,795)
Per share – basic and diluted	**(0.02)**	(1.00)	(0.02)	(0.02)	(0.43)	(0.03)	(0.05)	(0.06)	**(1.05)**	(0.59)	(0.69)
Cash provided from (used in) operations	**4,534**	(2,659)	1,669	3,232	4,984	9,027	8,690	10,038	**6,776**	32,739	91,147
Per share – basic and diluted	**0.03**	(0.02)	0.01	0.02	0.03	0.06	0.06	0.08	**0.04**	0.23	0.74
Adjusted funds flow (2)	**(387)**	(3,293)	2,803	2,398	3,373	9,290	7,429	9,492	**1,521**	29,584	92,452
Per share – basic and diluted	**(0.00)**	(0.02)	0.02	0.02	0.02	0.06	0.05	0.07	**0.01**	0.20	0.75
Total assets	**100,157**	152,714	296,920	293,417	276,160	458,637	462,746	453,300	**100,157**	276,190	452,767
Total other long-term liabilities	**2,818**	2,607	45,040	35,834	14,230	124,732	136,472	122,901	**2,818**	14,230	140,919

(1) Commodity prices and petroleum and natural gas ("**P&NG**") sales include realized gains or losses from commodity contract settlements.
(2) See definition under the "Non-GAAP Measures" section contained within this MD&A.

As indicated in the Financial Highlights tables above, the Company's quarterly average daily production decreased to 8,425 boe/d in the second quarter of 2016 as a result of an unscheduled outage of a mid-stream-operated gas plant in the Kaybob area due to a mechanical failure of its sulphur-handling infrastructure, pared-back drilling activity and natural field declines. Quarterly average daily production of 8,119 boe/d in the third quarter of 2016 reflects reduced drilling activity and natural field declines. The decrease of quarterly average daily production to 4,652 boe/d in the fourth quarter of 2016 reflects the Ante Creek Disposition closing on November 15, 2016 and both crude oil and natural gas sales pipelines restrictions in October 2016. Quarterly average daily production of 3,207 boe/d in the first quarter of 2017 declined from the previous quarter as a result of the Ante Creek Disposition (no volume from the Ante Creek field is reflected in the first quarter 2017 production figure). The increase in production in the second quarter of 2017 as compared to the preceding first quarter of 2017 is attributable to the start-up and commissioning of the 2-23 Facility (as defined herein) in Elmworth in June 2017. The increase in production to

4,010 boe/d in the third quarter of 2017 is due to production from the Elmworth field being reflected for the entire quarter. Quarterly production decreased to 2,416 boe/d in the fourth quarter of 2017 due to the aforementioned Disposition Transaction closing on October 17, 2017.

IBR's petroleum and natural gas sales fluctuate from quarter-to-quarter as a result of changes in commodity prices and/or production volumes. Please refer to the "*Petroleum and Natural Gas Sales and Commodity Pricing"* section for additional information.

Quarterly net income is impacted by the fluctuations in petroleum and natural gas sales, non-cash impairment charges, gains recognized on the disposition of assets, and unrealized gains and losses on risk management contracts. Specifically, the significant decrease in commodity market prices has resulted in the Company recording non-cash impairment charges of $115.6 million in the fourth quarter of 2016 and $102.5 million in the third quarter of 2017, respectively, which has affected the Company's reported amount of earnings.

The Company's total assets have decreased primarily as a result of the above mentioned non-cash impairment charges to property, plant and equipment, the Ante Creek Disposition in November 2016 and the Disposition Transaction in October 2017. The decrease in total other long-term liabilities in the first quarter of 2016 is primarily due to decreased bank debt drawdowns on the Company's bank credit facility as a result of a pared-back level of capital expenditures. The significant decrease in other long-term liabilities in the fourth quarter of 2016 is due to the Company paying off its entire outstanding bank debt balance in that quarter with the proceeds from the Ante Creek Disposition. The decline in other long-term liabilities in the third quarter of 2017 is a result of the classification of the Company's bank debt as current as at September 30, 2017 due to the demand nature of the Credit Facility (as defined herein) and due to $11.9 million of decommissioning obligations being transferred to a current liability position under *liabilities related to assets held for sale* and subsequently sold.

Petroleum and Natural Gas Production

Year 2017: For the fiscal year ended December 31, 2017, IBR's average daily production was 3,297 boe/d, with light crude oil and NGLs production accounting for 32% of the Company's volumes. Fiscal 2017 production represents a 58% decrease from the comparative fiscal 2016 production level of 7,895 boe/d (weighted 42% light oil and NGLs). Production for fiscal 2017 was comprised of 13,459 Mcf/d of natural gas, 793 Bbls/d of crude oil and 261 Bbls/d of NGLs. The decline in production levels year-over-year is a result of the Ante Creek Disposition and the Disposition Transaction. The comparative fiscal 2016 production figure includes production contribution from the Assets disposed of in the Disposition Transaction and Ante Creek field production up to the disposition closing date of November 15, 2016. Fiscal 2017 production does not include any Ante Creek field volumes and includes production from the Assets disposed of in the Disposition Transaction up to the date of closing, October 17, 2017.

Fourth Quarter 2017: IBR's fourth quarter 2017 production was 2,416 boe/d, comprised of crude oil and NGLs production averaging 688 Bbls/d and natural gas production averaging 10,369 Mcf/d. Fourth quarter 2017 production was lower than the preceding third quarter of 2017 production of 4,010 boe/d as a result of the Disposition Transaction. The Company's fourth quarter 2017 production reflects production from the disposed Assets from October 1 through to October 17 while the third quarter of 2017 included production from the disposed Assets for the entire three month period. Average daily production contribution from IBR's Elmworth Montney field and the disposed Assets was 1,946 boe/d and 470 boe/d, respectively, over the fourth quarter of 2017.

	2017 Quarterly Comparison					
	Q417	**Q317**	**Q217**	**Q117**	**Year 2017**	**Year 2016**
Crude oil (*Bbls/d*)	**440**	869	902	964	**793**	2,983
Natural gas (*Mcf/d*)	**10,369**	16,700	14,572	12,179	**13,459**	27,599
NGLs (*Bbls/d*)	**248**	358	225	214	**261**	312
Oil equivalent (*boe/d*)	**2,416**	4,010	3,556	3,207	**3,297**	7,895
Crude oil and NGLs weighting	**28%**	31%	32%	37%	**32%**	42%

Petroleum and Natural Gas Sales and Commodity Pricing

The Company's petroleum and natural gas ("**P&NG**") sales may fluctuate significantly from period-to-period as a result of changes in realized commodity prices and/or IBR's production volumes. Revenue from the sale of the Company's petroleum (crude oil and natural gas liquids) and natural gas is recognized when the risks and rewards of ownership of the commodity is transferred to the purchaser, based on volumes delivered to purchasers' contractual delivery points and when collection is reasonably assured by the Company. In 2017, IBR took greater than 95% of its working interest production "in-kind" and it was marketed and sold through three (3) primary commodity purchasers.

Year 2017: Primarily the result of lower production levels due to the strategic dispositions, total P&NG sales (including realized risk management commodity contract settlements) decreased substantially year-over-year with $32.7 million of revenue being realized in 2017, as compared to $77.3 million in fiscal 2016. A realized gain on risk management commodity contracts of $0.8 million was recognized for the year ended December 31, 2017 (December 31, 2016: realized loss of $1.2 million), with details of such discussed hereafter within the section "*Commodity Price Risk Management*".

With regards to industry commodity pricing, the West Texas Intermediate ("**WTI**") at Cushing, Oklahoma is the benchmark reference price for North American crude oil prices. Canadian oil prices, including IBR's crude oil, are based on price postings, which is WTI-adjusted for transportation, quality and the U.S./Canadian dollar currency conversion rates. During the year ended December 31, 2017 crude oil market prices increased 17%, as the WTI crude oil price benchmark averaged US$50.85 per Bbl as compared to US$43.47 per Bbl for the year ended December 31, 2016.

In a trend similar to that of industry crude oil prices, North American natural gas prices increased year-over-year. The Nymex Henry Hub natural gas benchmark price averaged US$3.02 per MMbtu, an 18% increase from the fiscal year 2016 average of US$2.55 per MMbtu. In fiscal 2017, IBR's natural gas sales were priced and indexed to the Alberta AECO-5A market reference price. Alberta AECO natural gas pricing increased 2% to $2.23 per Mcf from $2.18 per Mcf in fiscal 2016. However, notwithstanding a favorable start to fiscal 2017 with increased AECO gas prices, this Canadian benchmark gas price began to decline in the third quarter of 2017. AECO natural gas prices averaged $1.66 per Mcf in the second half of 2017 after averaging $2.74 per Mcf during the first six months of 2017. AECO basis differentials to Nymex Henry Hub significantly widened in the back half of 2017 and continue to be wide thus far in 2018.

Fourth Quarter 2017: The Company's quarterly P&NG sales for the three month period ended December 31, 2017, net of the realized gain on commodity contracts of $0.2 million, amounted to $5.6 million as compared to the prior third quarter of 2017 amount of $8.1 million (net of the realized gain on commodity contracts of $0.4 million) and the $13.4 million (net of the realized loss on commodity contracts of $1.1 million) recognized in the fourth quarter of 2016.

IBR's realized crude oil price for the three month period ended December 31, 2017 averaged $67.93 per Bbl, an increase of 26% from the $53.93 per Bbl realized in the third quarter of 2017. The Company's fourth quarter 2017 natural gas price of $2.03 per Mcf was approximately 9% higher than the third quarter 2017 natural gas price of $1.87 per Mcf. The Company's Elmworth natural gas price benefits from the high heat content of its Montney natural gas. Fourth quarter 2017 WTI benchmark crude oil pricing of US$55.30 per Bbl increased 15% over the preceding third quarter 2017 average of US$48.20 per Bbl and increased 12% from the comparative fourth quarter 2016 price of $49.29 per Bbl. The fourth quarter 2017 Nymex Henry Hub natural gas price averaged US$2.93 per MMbtu, a 1% decrease over the third quarter 2017 average of US$2.95 per MMbtu. The Alberta AECO natural gas price averaged $1.67 per Mcf for the quarter ended December 31, 2017, a 1% increase over the third quarter 2017 average of $1.65 per Mcf, and a 46% decrease from the comparative fourth quarter 2016 price of $3.11 per Mcf.

The following table highlights IBR's realized commodity prices and industry benchmark prices:

	2017 Quarterly Comparison					
	Q417	**Q317**	**Q217**	**Q117**	**Year 2017**	**Year 2016**
IBR prices (net of realized commodity contract settlements)						
Natural gas ($/Mcf)	**2.03**	1.87	3.03	2.98	**2.46**	2.22
Crude oil ($/Bbl)	**67.93**	53.93	56.72	61.39	**58.92**	47.80
NGLs ($/Bbl)	**40.60**	27.91	42.74	45.31	**37.63**	23.86
Oil equivalent ($/boe)	**25.24**	21.94	29.52	32.76	**27.18**	26.76
Industry benchmark prices						
WTI Cushing oil (US$/Bbl)	**55.30**	48.20	48.15	51.78	**50.85**	43.47
Nymex gas (US$/MMbtu)	**2.93**	2.95	3.14	3.06	**3.02**	2.55
AECO gas ($/Mcf)	**1.67**	1.65	2.78	2.69	**2.23**	2.18
Exchange rate (US$/C$)	**0.7870**	0.7980	0.7439	0.7554	**0.7711**	0.7555

The following table provides the composition of P&NG sales by commodity type:

(net of realized commodity contract settlements)	2017 Quarterly Comparison					
($000s)	**Q417**	**Q317**	**Q217**	**Q117**	**Year 2017**	**Year 2016**
Crude oil sales	**2,750**	4,311	4,656	5,326	**17,043**	52,193
Natural gas sales	**1,933**	2,866	4,021	3,261	**12,081**	22,405
NGLs sales	**927**	918	875	871	**3,591**	2,724
Petroleum and natural gas sales	**5,610**	8,095	9,552	9,458	**32,715**	77,322
Crude oil and NGLs weighting	**66%**	65%	58%	66%	**63%**	71%

Commodity Price Risk Management

As a means of managing commodity price volatility and its impact on IBR's cash provided by operating activities and adjusted funds flow, from time-to-time the Company may enter into various derivative financial instruments and physical delivery commodity contract arrangements, primarily commodity price contracts, to manage fluctuations in crude oil and natural gas market prices. Any such contracts are entered into with investment grade counter-parties that IBR believes present minimal credit risk. The Company does not utilize derivative financial instruments for speculative trading purposes.

IBR did not have any outstanding derivative contracts as at December 31, 2017 and March 20, 2018.

The following natural gas derivative contract was outstanding in fiscal 2017:

Term	Contract Type	Volume (GJs/d)	Reference Point	Contract price per GJ
April 1, 2017 - October 31, 2017	Swap	3,000	AECO 5A	Cdn. $ 3.00

IBR recognized a realized gain of $0.8 million for the year ended December 31, 2017 as a result of the natural gas risk management commodity contract which was settled during the year (December 31, 2016: realized loss of $1.2 million). Unsettled derivative financial contracts are recorded at the date of the financial statements based on the fair value of the respective contracts. Changes in fair value result from volatility in forward commodity prices and changes in the balance of unsettled contracts between periods. The change in fair value is recognized as an unrealized gain or loss on the statement of loss. For the year ended December 31, 2017, the Company recorded a $0.1 million unrealized gain (December 31, 2016: $0.1 million unrealized loss).

Other Income

The Company's other income is comprised of the following:

	2017 Quarterly Comparison					
($000s)	**Q417**	Q317	Q217	Q117	**Year 2017**	Year 2016
Transportation income	**161**	604	382	593	**1,740**	950
Gathering, compression, road use and other income	**40**	189	261	260	**750**	1,128
Other income	**201**	793	643	853	**2,490**	2,078

Transportation income relates to the Company's commercial efforts to mitigate its unutilized capacity attributable to its gas transportation firm receipt service obligations through natural gas supply transactions with other producers in the market to meet the shortfall contract quantities. Gathering, compression, road use and other income relates to revenue earned through third party usage of the Company's access roads and other income earned by the Company primarily relating to gas gathering and compression income and pipeline transportation income.

The Company's other income for the year ended December 31, 2017 amounted to $2.5 million. The 20% increase from fiscal 2016 other income of $2.1 million is primarily due to the aforementioned Ante Creek Disposition which closed on November 15, 2016, and resulted in additional unutilized capacity after the disposition in respect to the Company's contracted firm service gas transportation quantities.

Petroleum and Natural Gas Royalties

Year 2017: Petroleum and natural gas royalties for the year ended December 31, 2017 amounted to $2.4 million, resulting in a corporate effective royalty rate of 7.5%, as compared to the fiscal 2016 royalty encumbrances of $11.2 million with an effective royalty rate of 14.2%. The decline in the corporate royalty rate year-over-year is primarily attributable to royalties from the Ante Creek field not being reflected in fiscal 2017 as a result of the Ante Creek Disposition. The Ante Creek field had a higher average royalty rate in comparison to the Company's other producing fields. Thus, upon the removal of the Ante Creek field, the Company's average royalty rate was lowered.

Fourth Quarter 2017: For the three month period ended December 31, 2017, the Company's P&NG royalties were $0.3 million with an effective corporate royalty rate of 6.4% (three months ended December 31, 2016: $1.7 million and an effective corporate royalty rate of 12.0%). The corporate royalty rate for the fourth quarter of 2017 was lower than the preceding third quarter 2017 rate of 10.4% due to the Disposition Transaction, which closed on October 17, 2017. The disposed Assets had a higher average royalty rate than the Company's remaining Elmworth field. The fourth quarter 2017 royalty rate for the Company's Elmworth field was approximately 3.2%.

	2017 Quarterly Comparison					
($000s)	**Q417**	Q317	Q217	Q117	**Year 2017**	Year 2016
Crown	**310**	676	300	707	**1,993**	10,718
Freehold and overrides	**36**	123	140	94	**393**	445
Total royalties	**346**	799	440	801	**2,386**	11,163
Corporate royalty rate (1)	**6.4%**	10.4%	4.7%	8.5%	**7.5%**	14.2%

(1) Royalty rate is based on P&NG sales, excluding any realized gains or losses from risk management commodity contract settlements.

On January 1, 2017, the Alberta Government's new royalty framework for the province's oil and gas industry, the Modernized Royalty Framework ("**MRF**") became effective. Wells drilled prior to January 1, 2017 will continue to be governed by the previous "Alberta Royalty Framework" for a period of 10 years until January 1, 2027. The MRF is structured in three phases: (i) Pre-Payout, (ii) Mid-Life, and (iii) Mature. During the Pre-Payout phase, a fixed 5% royalty will apply until the well reaches payout. Well payout occurs when the cumulative revenue from a well is equal to the Drilling and Completion Cost Allowance (determined by a formula that approximates drilling and completion costs for wells based on depth, length and historical costs). Post-payout, the Mid-Life phase applies a higher royalty rate than the Pre-Payout phase. Mid-life phase royalty rates are determined by resource and commodity market prices. In the Mature phase, once a well reaches the tail end of its cycle and production falls below a Maturity Threshold of 40 boe/d, the royalty rate will move to a sliding scale (based on volume and price) with a minimum royalty rate of 5%. The downward adjustment of the royalty rate in the Mature phase is intended to account for the higher per-unit fixed cost involved in operating an older well.

Net Operating Expenses

Year 2017: For the year ended December 31, 2017, the Company's net operating expenses, which are costs to operate and maintain oil and gas wells and related field infrastructure, were $14.0 million (year ended December 31, 2016: $17.1 million) or $11.67 on an oil-equivalent per unit basis, which represents a 97% increase from the field production per-unit cost of $5.92 per boe in fiscal 2016. Per-unit net operating expenses for the year ended December 31, 2017 increased primarily due to the reduced production volumes covering the fixed operating cost component, coupled with the Ante Creek Disposition resulting in the sale and removal of the Ante Creek field that had a lower operating cost per unit profile than the remainder of the Company's producing fields.

Fourth Quarter 2017: On an oil-equivalent per unit basis, fourth quarter 2017 field production net operating costs of $10.43 per boe were 21% lower when compared with the preceding third quarter 2017 per-unit expense of $13.25 per boe. Net operating expenses for the three months ended December 31, 2017 were lower on a boe basis from the preceding third quarter of 2017 due to a higher level of well workovers, pump replacement activity and compressor maintenance at Waskahigan and Kaybob in the third quarter, in addition to prior period third-party gas plant adjustments at Kaybob also being reflected in the third quarter. Additionally, the Assets disposed of in the Disposition Transaction had a higher average per-unit net operating cost than the Company's remaining Elmworth field. In the fourth quarter, the disposed Assets net operating costs recognized, excluding the Elmworth field, were approximately $14.40 per boe. The Company's transition to a geographically concentrated, Montney-focused play with its associated lower operating cost structure is expected to result in lower reported net operating expenses prospectively.

	2017 Quarterly Comparison					
($000s)	**Q417**	**Q317**	**Q217**	**Q117**	**Year 2017**	**Year 2016**
Operating expenses	**2,359**	5,078	3,792	3,564	**14,793**	18,235
Less: Gathering, compression, road use and other income	**(40)**	(189)	(261)	(260)	**(750)**	(1,128)
Net operating expenses (1)	**2,319**	4,889	3,531	3,304	**14,043**	17,107
Per unit ($/boe)	**10.43**	13.25	10.91	11.45	**11.67**	5.92

(1) See definition under the "*Non-GAAP Measures*" section contained within this MD&A.

Net Transportation Expenses

Year 2017: IBR incurs transportation costs on the crude oil and natural gas it produces once the respective commodity enters a feeder or main pipeline at the first point of sale or title transfer point. In fiscal 2017, these costs primarily encompassed oil sales pipeline tariffs, pipeline fuel surcharges and transportation costs associated with the capacity usage of mid-stream natural gas sales pipelines. The net cost of transporting and distributing natural gas and crude oil production to market delivery points during the year ended December 31, 2017 amounted to $5.9 million (year ended December 31, 2016: $9.4 million) or $4.93 on an oil-equivalent per unit basis (year ended December 31, 2016: $3.27 per boe).

Fourth Quarter 2017: The Company's net transportation expense for the fourth quarter of 2017 was $6.65 per boe, representing a 10% increase from the preceding third quarter 2017 cost of $6.03 per boe.

The increase in the Company's per unit net transportation cost for both the three and twelve months ended December 31, 2017 versus the comparable 2016 periods is primarily the result of additional oil transportation take-or-pay financial commitments commencing July 1, 2017, upon the completion and in-service of the Pembina Peace Pipeline Phase III Expansion. The take-or-pay commitments, for both Alliance and Pembina firm service arrangements, were partially mitigated upon the closing of the aforementioned Disposition Transaction wherein fifty percent (50%) of these commitments were permanently assigned to the purchaser. Additionally, for all reporting periods, the Company partially mitigated its unutilized Alliance take-or-pay gas transportation obligations through third party arrangements as disclosed in the table hereafter.

	2017 Quarterly Comparison					
($000s)	**Q417**	Q317	Q217	Q117	**Year 2017**	Year 2016
Transportation expenses	**1,639**	2,830	1,609	1,596	**7,674**	10,397
Less: Transportation income	**(161)**	(604)	(382)	(593)	**(1,740)**	(950)
Net transportation expenses [(1)]	**1,478**	2,226	1,227	1,003	**5,934**	9,447
Per unit ($/boe)	**6.65**	6.03	3.79	3.47	**4.93**	3.27

(1) See definition under the "*Non-GAAP Measures*" section contained within this MD&A.

General and Administrative Expenses

Year 2017: General and administrative ("**G&A**") expenses during the year ended December 31, 2017 were higher than the prior year, amounting to $8.2 million or $6.79 on an oil-equivalent per unit basis (year ended December 31, 2016: $6.9 million or $2.38 per boe). Gross cash G&A before recoveries and capitalization increased by $0.8 million year-over-year, due primarily to costs in the aggregate amount of approximately $2.2 million incurred in connection with the Company's executive management restructuring undertaken in July 2017 and associated financial advisory and legal fees. This increase was offset by cost savings achieved in fiscal 2017 in respect to audit and independent engineering fees, consultancy fees and corporate insurance due to the reduced operating size of the Company year-over-year.

Fourth Quarter 2017: In the fourth quarter of 2017, expensed G&A amounted to $1.7 million, a 47% decrease from the $3.3 million in the third quarter of 2017 and a 23% decrease from the $2.2 million expensed in the fourth quarter of 2016. Gross G&A decreased by $1.6 million over the preceding third quarter primarily as a result of the aforementioned executive management restructuring undertaken in the prior quarter. Fourth quarter 2017 gross G&A included annual year-end costs associated with IBR's independent engineering reserves report and the fiscal 2017 financial statement audit. The quarter also included employee termination severance costs of $386 thousand disbursed in connection with the Company's head office staff count reductions. At year end 2017, IBR employed 15 head office personnel, as compared to the 20 employees prior to staff reductions, and engaged the services of three (3) consultants on a part-time basis. Adjusting for the employee termination costs in the fourth quarter, "normalized" G&A expense for the quarter would have been $1.3 million or $6.02 per boe.

	2017 Quarterly Comparison					
($000s)	**Q417**	Q317	Q217	Q117	**Year 2017**	Year 2016
Gross	**1,981**	3,568	1,622	2,158	**9,329**	8,485
Recoveries and capitalized	**(256)**	(292)	(328)	(287)	**(1,163)**	(1,608)
Expensed	**1,725**	3,276	1,294	1,871	**8,166**	6,877
Per unit ($/boe)	**7.76**	8.88	4.00	6.48	**6.79**	2.38

Share-Based Compensation

Share-based compensation costs ("**SBC**") are non-cash charges that reflect the estimated value of stock options and incentive awards issued to directors, officers and employees of IBR. The value of the award is recognized as an expense over the period from the grant date to the date of final vesting of the award. The Company capitalizes a portion of share-based compensation expense which is directly attributable to personnel involved in exploration and development capital investment activities. IBR utilizes the fair value method for measuring share-based compensation expenses. Compensation cost is measured at the grant date based on the fair value of the option using a Black-Scholes option pricing model and is recognized over the option vesting period. Some of the inputs to the option valuation model are subjective, including assumptions regarding expected stock price volatility, forfeiture rates, interest rates and tenure to exercise. This compensation expense may not represent actual cash compensation realized by the recipients of the awards upon future exercise.

As of December 31, 2017, total unrecognized SBC of $1.9 million, related to 8.6 million unvested stock options, is expected to be recognized in future periods over the remaining vesting terms. As of the date of this MD&A, 10,121,000 stock options with a weighted average exercise price of $0.76 per option were outstanding and exercisable at various dates through to February 1, 2023. During the year ended December 31, 2017, 7.6 million stock options were granted at a weighted average exercise price of $0.65 per option and 6.6 million options were forfeit as a resulting of the restructuring and management change. On April 17, 2017, a total of 4.5 million options with a weighted average exercise price of $7.18 per option were surrendered for cancellation.

On September 7, 2017, the Company closed the aforementioned private placement resulting in the issuance of 5.35 million Warrants. A portion of the private placement gross proceeds was allocated to the Warrants based upon the difference in the Unit offering price and the closing value of the Company's common shares on the date of closing of the private placement. The fair value of the Warrants was calculated using the Black-Scholes pricing model using the following assumptions: an expected life of four (4) years, a volatility rate of 65.21% and a risk-free interest rate of 1.60%. The difference between the fair value of the Warrants and the value allocated on initial grant will be recognized as stock-based compensation over the vesting term of the Warrants with a corresponding increase to the Warrants carrying value. For the year ended December 31, 2017, the Company recorded a net SBC expense of $51 thousand in respect to the Warrants.

The Company has a long-term incentive plan (the "**Plan**") whereby the Company can issue incentive awards to employees, officers, directors and other service providers of the Company in the form of common shares of IBR. The awards granted vest as to one-third on each of the first, second and third anniversaries from the date of grant and have an expiry date of December 15th of the tenth year following the year in which the award was granted. As at December 31, 2017, a total of 777,167 restricted common share awards were outstanding and exercisable at various dates through to December 15, 2027. A service cost recovery (net of capitalization) of $249 thousand related to the restricted common share awards has been recognized and recorded in share-based compensation expense for the year ended December 31, 2017 as a result of forfeitures in the period (year ended December 31, 2016: net service cost expense of $569 thousand). As of December 31, 2017, total unrecognized SBC of $0.3 million, related to 0.7 million unvested restricted common share awards, is expected to be recognized in future periods over the remaining vesting terms.

The Company's share-based compensation expense for the year ended December 31, 2017, net of capitalization, was $0.7 million as compared to $3.2 million for the year ended December 31, 2016. The decrease in SBC expense for the year ended December 31, 2017 is primarily attributable to the forfeiture of both unvested options and unvested restricted common share awards during the year resulting in the reversal of the previously recognized SBC related to the unvested options and unvested restricted common share awards.

	2017 Quarterly Comparison						
($000s)	**Q417**	**Q317**	**Q217**	**Q117**		**Year 2017**	**Year 2016**
SBC (pre-capitalization)	**190**	(251)	608	653		**1,200**	4,685
SBC (capitalized)	**(98)**	58	(223)	(201)		**(464)**	(1,456)
SBC (net)	**92**	(193)	385	452		**736**	3,229

Finance Expenses

The Company's finance expenses comprise interest expense and standby fees on bank debt and accretion of the discount on decommissioning obligations.

	2017 Quarterly Comparison						
($000s)	**Q417**	**Q317**	**Q217**	**Q117**		**Year 2017**	**Year 2016**
Interest expense and standby fees on bank debt	**129**	198	257	81		**665**	3,144
Accretion of decommissioning obligations	**16**	83	86	81		**266**	384
Total finance expense	**145**	281	343	162		**931**	3,528
Average bank debt level (1)	**-**	31,592	27,729	11,467		**17,697**	92,104
Average bank debt interest rate (%)	**5.2**	4.3	3.4	4.3		**4.1**	3.3
Average bank Prime lending rate (%)	**3.2**	3.0	2.7	2.7		**2.9**	2.7

(1) Average bank debt based on simple average within respective periods.

Interest Expense

During the year ended December 31, 2017, the Company incurred $0.7 million in interest charges related to its outstanding bank debt, as compared to $3.1 million for the comparative 2016 fiscal period. This decrease is attributable to a lower average bank debt level throughout fiscal 2017 as compared to the average outstanding bank debt level in 2016. IBR's outstanding bank debt balance was reduced to zero upon the receipt of funds received from the closing of the Disposition Transaction on October 17, 2017. The Company's weighted-average effective interest rate approximated 4.1% during 2017.

Interest Rate Risk Management

IBR has a floating interest rate on any bank debt outstanding, which subjects the Company to interest rate risk. From time-to-time, IBR may mitigate the risk of increasing market interest rates by entering into financial derivative contracts to fix interest rates. Borrowings under the Company's Credit Facility bear interest at a rate equal to the Lender's prime rate plus 2.0% per annum.

Accretion Expense

Accretion expense represents the change in the time value of the decommissioning and restoration obligations. Accretion expense for the year ended December 31, 2017 was $0.3 million. Please refer to the "*Decommissioning Obligations"* section hereafter.

The total decommissioning obligation liability may increase over a period based on new decommissioning obligations incurred from drilling wells, constructing facilities or acquiring operations. Similarly, this total obligation can be reduced as a result of liabilities released upon dispositions or due to abandonment work undertaken which reduces future obligations. Adjusting the underlying assumptions used in the decommissioning obligation calculation, such as abandonment timing, cost estimates, the inflation rate or the discount rate, may increase or decrease the total decommissioning obligation liability.

Depletion and Depreciation

Depletion and depreciation expense is calculated on a unit-of-production basis. This provision, on an oil equivalent per-unit basis, fluctuates period-to-period primarily as a result of changes in the underlying proved plus probable crude oil and natural gas reserve base and in the amount of costs subject to depletion and depreciation. These costs are segregated and depleted on an area-by-area or field component basis relative to the respective underlying proved plus probable reserves base. The carrying value of undeveloped land in exploration and evaluation assets, which has no proved and/or probable reserves assigned to it, is depreciated over its term to expiry which is also charged to depletion and depreciation expense.

Year 2017: Depletion and depreciation expense for the year ended December 31, 2017 amounted to $19.0 million or $15.77 on a per boe basis (December 31, 2016: $61.2 million or $21.17 per boe). The 26% decrease in rate on a per-unit basis from the prior year is primarily a result of the Disposition Transaction. The Company reclassified its Assets disposed of in the disposition to Tangle Creek as *assets held for sale* commencing on August 31, 2017, the date in which the purchase and sale agreement was signed. *Assets held for sale* are not subject to depletion or depreciation. Thus, all assets related to Waskahigan, Grizzly, Kaybob, Gilby, Pine Creek and other minor Alberta properties ceased being depleted on August 31, 2017. Furthermore, the Company's sole remaining field, Elmworth, has a lower depletion and depreciation rate than the disposed Assets.

Fourth Quarter 2017: IBR's depletion and depreciation expense for the fourth quarter ended December 31, 2017 amounted to $2.0 million. On a combined unit-of-production basis, the depletion and depreciation provision for the fourth quarter of 2017 was $9.15 per boe, as compared to $12.92 per boe in the previous third quarter of 2017 and $26.30 per boe in the comparative fourth quarter of 2016. The decrease in the depletion rate from both the third quarter of 2017 and the fourth quarter of 2016 is due to the Disposition Transaction. The fourth quarter of 2017 does not include any depletion or depreciation related to the disposed Assets.

The depletion and depreciation provision for the fourth quarter of 2017 excluded salvage value of $0.5 million (December 31, 2016: $4.4 million).

	2017 Quarterly Comparison					
	Q417	**Q317**	**Q217**	**Q117**	**Year 2017**	**Year 2016**
Depletion and depreciation ($000s) (1)	**2,034**	4,768	5,852	6,326	**18,980**	61,171
Per unit ($/boe)	**9.15**	12.92	18.09	21.92	**15.77**	21.17

(1) Includes depletion of the capitalized portion of the decommissioning obligation which was capitalized to the property, plant and equipment balance and is being depleted over the life of the Company's proved plus probable reserves.

Impairment of Property, Plant and Equipment

At December 31, 2017, the Company assessed its sole remaining Greater Elmworth CGU for indicators of impairment. Due to the decline in the natural gas commodity price environment resulting in a macro impairment indicator, the Company tested its CGU (as defined herein) for impairment.

The recoverable amount of the CGU was estimated based on the higher of the *value in use* and the *fair value less costs to sell*. The recoverable amount for the year-ended December 31, 2017 was determined using *fair value less costs to sell*, based on discounted before tax cash flows of proved plus probable crude oil and natural gas reserves estimated by the Company's independent qualified reserves evaluators using forecasted prices and costs and a discount rate of 15% and the fair value of undeveloped land as evaluated by the Company's independent land appraiser. The values assigned to the key assumptions represent IBR management's assessment of future trends in the oil and natural gas industry and are based upon both external and internal sources.

The Company determined that there was no impairment to the Greater Elmworth CGU as at December 31, 2017.

For the prior comparative year 2016, the Company's CGUs were assessed for indicators of impairment. Due to the transformational nature of the Ante Creek Disposition on the Company's operations, the Company tested the remaining assets in the oil-weighted Greater Waskahigan CGU for impairment. This CGU prior to the Ante Creek Disposition encompassed the Ante Creek, Waskahigan and Grizzly fields. The Company also determined that impairment indicators existed for the Company's gas-weighted Greater Kaybob CGU, West Central Alberta CGU and Central Alberta CGU. The impairment tests indicated that the recoverable amounts for both the Greater Waskahigan CGU and the West Central Alberta CGU were less than their carrying values and as such, an aggregate non-cash impairment charge to property, plant and equipment of $115.6 million of which $114.3 million related to the Greater Waskahigan CGU and $1.3 million related to the West Central Alberta CGU was recognized in fiscal 2016. The Company did not identify any impairment triggers on its Greater Elmworth CGU.

Deferred Taxes

Deferred income taxes arise from differences between the accounting and tax basis of assets and liabilities. The estimate of deferred income taxes is based on the current tax status of the Company, enacted legislation and management's best estimates of future events. For the year ended December 31, 2017, the Company recorded a deferred tax expense of $39.8 million, as compared to a $28.2 million deferred tax reduction recognized in the same period of 2016. In the third quarter of 2017, the Company derecognized the previously recorded deferred tax asset due to uncertainty of the future realization of the deferred tax asset. The derecognition was a result of the restructuring of the Company's asset base due to the aforementioned Disposition Transaction.

	2017 Quarterly Comparison						
($000s)	**Q417**	**Q317**	**Q217**	**Q117**		**Year 2017**	**Year 2016**
Deferred tax expense (reduction)	**-**	41,305	(642)	(865)		**39,798**	(28,242)

During the year IBR was not subject to any corporate cash income tax due to significant tax pool balances, which as at December 31, 2017 aggregate to approximately $325.3 million (December 31, 2016: $357.6 million) and estimates sufficient tax pools available to shelter estimated income until 2028. The following table outlines the Company's estimated tax pools as at December 31, 2017 and 2016:

Tax Pool Category (1)	Deduction Rate	**December 31, 2017**	December 31, 2016
		(millions)	(millions)
Canadian exploration expense (CEE)	100%	**$ 11.4**	$ 7.1
Canadian development expense (CDE)	30%	**69.1**	125.9
Canadian oil and gas property expense (COGPE)	10%	**-**	4.3
Non-capital losses (NCL)	100%	**146.6**	101.9
Undepreciated capital cost (UCC)	25%	**94.9**	112.9
Share issue costs and other	Various	**3.3**	5.5
Total		**$ 325.3**	$ 357.6

(1) Actual tax pool amounts may vary as corporate tax returns are finalized and filed.

Operating Netback per Boe and Net Loss per Boe

The following table highlights the Company's operating netback, adjusted funds flow and net loss on a per boe basis for both the years ended December 31, 2017 and 2016 and the three months ended December 31, 2017 and 2016. The Company's operating netback was $8.60 per boe for the 2017 year, representing a 37% decrease from 2016. The operating netback decreased 52% to $6.60 per boe in the fourth quarter of 2017 from the comparable fourth quarter of 2016. The relatively lower netback production associated with the disposed Assets, in comparison to the Elmworth assets, tempered the Company's recorded fourth quarter 2017 overall operating netback. In the fourth quarter, the disposed Assets negative operating netback was ($3.49) per boe, significantly lower than IBR's Elmworth positive operating netback for the quarter of $10.67 per boe.

Columns may not add due to rounding	Fourth Quarter (2)			Year Ended December 31 (2)		
($/boe)	**2017**	2016	% Change	**2017**	2016	% Change
Petroleum and natural gas sales	**24.27**	33.80	(28)	**26.55**	27.19	(2)
Realized gain (loss) on risk management contracts	**0.96**	(2.57)	(137)	**0.63**	(0.43)	(247)
Royalties	**(1.56)**	(4.05)	(61)	**(1.98)**	(3.86)	(49)
Net operating expenses (1)	**(10.43)**	(9.67)	8	**(11.67)**	(5.92)	97
Net transportation expenses (1)	**(6.65)**	(3.64)	83	**(4.93)**	(3.27)	51
Operating netback (1)	**6.60**	13.88	(52)	**8.60**	13.71	(37)
General and administrative expense	**(7.76)**	(5.21)	49	**(6.79)**	(2.38)	185
Interest expense	**(0.58)**	(0.79)	(27)	**(0.55)**	(1.09)	(50)
Adjusted funds flow (1)	**(1.74)**	7.88	(122)	**1.26**	10.24	(88)
Depletion and depreciation	**(9.15)**	(26.30)	(65)	**(15.77)**	(21.17)	(26)
Accretion	**(0.07)**	(0.20)	(65)	**(0.22)**	(0.13)	69
Share-based compensation expense	**(0.41)**	(1.52)	(73)	**(0.61)**	(1.12)	(46)
Impairment of property, plant and equipment	**-**	(269.99)	(100)	**(85.15)**	(39.99)	113
Gain on non-monetary property exchange	**-**	-	-	**0.42**	0.13	223
Gain (loss) on property disposition	**(4.12)**	83.04	(105)	**(0.76)**	12.53	(106)
Unrealized gain (loss) on risk management contracts	**(0.87)**	1.52	(157)	**0.08**	(0.03)	(367)
Deferred tax reduction (expense)	**-**	52.54	(100)	**(33.07)**	9.77	(438)
Net loss	**(16.36)**	(153.05)	(89)	**(133.82)**	(29.77)	350

(1) See definition under the "*Non-GAAP Measures*" section contained within this MD&A.

(2) **The Company's reported fourth quarter 2017 and Year 2017 results include operational and financial contribution from the disposed Assets up to the date of closing of October 17, 2017, when control transferred**.

Cash Provided from Operating Activities, Adjusted Funds Flow and Net Loss

IBR's profit and cash flow generating capability is primarily a function of commodity prices, the cost to add proved and probable crude oil and natural gas reserves through drilling and acquisitions and the cost to produce its reserves. In the year ended December 31, 2017, the Company recorded cash provided from operating activities of $6.8 million and adjusted funds flow of $1.5 million and generated a net loss of $161.0 million.

	2017 Quarterly Comparison					
($000s, except share data)	**Q417**	Q317	Q217	Q117	**Year 2017**	Year 2016
Cash provided from operating activities	**4,534**	(2,659)	1,669	3,232	**6,776**	32,739
Per share – basic and diluted	**0.03**	(0.02)	0.01	0.02	**0.04**	0.23
Adjusted funds flow (1)	**(387)**	(3,293)	2,803	2,398	**1,521**	29,584
Per share – basic and diluted	**(0.00)**	(0.02)	0.02	0.02	**0.01**	0.20
Net loss	**(3,637)**	(151,799)	(2,854)	(2,758)	**(161,048)**	(86,019)
Per share – basic and diluted	**(0.02)**	(1.00)	(0.02)	(0.02)	**(1.05)**	(0.59)

(1) See definition under the "*Non-GAAP Measures*" section contained within this MD&A.

Available-for-Sale Financial Asset

In conjunction with the Disposition Transaction, the Company received 13,846,153 common shares of Tangle Creek as part of the consideration. The privately-traded common shares have been classified as an *available-for-sale financial asset*. *Available-for-sale financial assets* are non-derivative financial assets that are not classified as loans or receivables, held-to-maturity investments or financial assets at fair value through profit or loss. *Available-for-sale financial assets* are initially measured at fair value net of attributable transaction costs and subsequently measured at fair value with changes in fair value recognized in other comprehensive income ("**OCI**"). The fair value of the asset is determined using current or recent quoted prices for the privately-traded common shares, which comprises the financial asset. The Tangle Creek shares were valued at approximately $0.65 per share at the date of acquisition and as at December 31, 2017 based upon the issue price of Tangle Creek's most recent equity financing completed in conjunction with the Disposition Transaction resulting in a fair value of $9.0 million.

Decommissioning Obligations

As at December 31, 2017, the Company recorded decommissioning obligations of $2.8 million, as compared to $14.2 million at December 31, 2016. During the year, IBR's decommissioning obligation liability decreased by approximately $11.4 million, which is comprised of: i) $1.0 million of liabilities incurred as a result of the Company's 2017 drilling program, ii) $11.9 million of liabilities released upon disposition, iii) $0.2 million decrease related to changes in expected abandonment dates, iv) $0.6 million decrease due to changes in discount rate, v) $0.3 million of accretion and vi) $60 thousand of actual decommissioning cash expenditures incurred.

Decommissioning liabilities are established using the present value of best estimate future costs that are required to settle present obligations related to future activities to plug and abandon its crude oil and natural gas wells and to dismantle and remove associated production facilities. IBR is progressive with its decommissioning liability management program; it conducts such in accordance and compliance with the framework and parameters required by the Alberta Energy Regulator (the "**AER**") for its Alberta-based operations, primarily the AER's *Directive 006: License Liability Rating (LLR) Program* and their *Directive 013: Suspension Requirement for Wells*.

Capital Expenditures

Year 2017: In fiscal 2017, the Company incurred approximately $46.0 million on exploration and development expenditures. In 2017, a total of six (6.0 net) Montney horizontal crude oil wells were drilled, as compared to a drilling program in fiscal 2016 of eight (8.0 net) horizontal wells. IBR's 2017 drilling program amounted to $25.4 million and focused upon the successful drilling of five (5.0 net) wells at Elmworth and one (1.0 net) well in Waskahigan in the first quarter of 2017.

IBR's fiscal 2017 facilities and well equipment costs were $19.3 million, which includes $13.7 million of initial capital related to the construction of the Company's Elmworth 2-23-68-3W6 oil battery and gas handling facility ("**2-23 Facility**"). On June 22, 2017, the Company announced the successful commissioning and start-up of its 100% owned and operated 2-23 Facility. Fiscal 2017 capital invested in facilities and well equipment also includes the wellsite equipping and tie-in costs related to four (4.0 net) of the wells drilled in fiscal 2017.

As previously mentioned, on October 17, 2017, IBR closed the disposition of the Company's crude oil and natural gas assets in the Waskahigan, Grizzly, Kaybob, Gilby and Pine Creek areas, in addition to other minor Alberta properties, for total consideration of $77.0 million, net of closing adjustments (the "**Disposition Transaction**"). Assets sold in the Disposition Transaction included reserves, land acreage, infrastructure facility and pipeline interests. The Disposition Transaction resulted in the recognition of an impairment loss of $102.5 million when the disposed assets were classified as *assets held for sale* as at September 30, 2017. A loss on disposition of $0.3 million related to the sale was recognized in the fourth quarter of 2017.

On March 15, 2017, the Company exchanged undeveloped land assets in the Waskahigan area with an arm's-length party on a non-monetary basis. The lands disposed of by the Company had a nil net book value as the lands had been fully depreciated. The acquired lands were measured at fair value. The exchange resulted in the recognition of a $0.5 million gain.

Fourth Quarter 2017: In the fourth quarter of 2017, the Company's exploration and development capital program was approximately $7.5 million. Drilling and completion costs for the quarter were approximately $6.1 million and include the horizontal drilling cost of a 100% working interest development infill Elmworth Montney well, initial drilling costs for a second infill horizontal Montney well and drilling and completion costs for an Elmworth water disposal well. Fourth quarter 2017 facilities and well equipment costs were $1.3 million, which primarily relates to costs incurred in respect to the 2-23 Facility for gas compression installation, additional power generation and water disposal well pump gear.

The Company will remain disciplined and flexible with its remaining 2018 capital spending as it monitors business conditions and commodity prices. Capital spending may vary due to a variety of factors, including drilling results, natural gas and crude oil prices, economic conditions, prevailing debt and/or equity markets, equipment availability, permitting and any future acquisitions. The timing of most capital expenditures is discretionary. Consequently, the Company has a significant degree of flexibility to adjust the level of its capital investments as circumstances warrant. Additionally, to enhance flexibility of the Company's capital program, IBR typically does not enter into material long-term obligations with any of its drilling contractors or service providers with respect to its operated natural gas and crude oil properties.

The composition of IBR's capital investment program is outlined as follows:

	2017 Quarterly Comparison					
($000s)	Q417	Q317	Q217	Q117	Year 2017	Year 2016
Land	50	758	71	446	1,325	6,108
Seismic	-	-	-	-	-	31
Drilling and completions	6,114	4,115	1,117	14,071	25,417	28,159
Facilities and well equipment	1,327	2,820	5,058	10,070	19,275	5,545
Total exploration and development	7,491	7,693	6,246	24,587	46,017	39,843
Other (1)	149	137	270	27	583	922
Property acquisitions	-	-	-	-	-	10,020
Property dispositions (2)	(76,342)	-	-	-	(76,342)	(109,982)
Total capital expenditures	(68,702)	7,830	6,516	24,614	(29,742)	(59,197)

(1) Year 2017 includes capitalized G&A of $0.5 million (Year 2016: $0.9 million) and excludes non-cash capitalized stock-based compensation of $0.5 million (Year 2016: $1.5 million).

(2) Year 2017 property dispositions reflects the total consideration received from the Disposition Transaction , net of closing adjustments and costs to sell, comprised of $68.0 million in cash and approximately 13.85 million common shares in Tangle Creek having a value of $9.0 million. Year 2017 also includes a $0.6 million adjustment charge related to the final closing adjustments recorded in 2017 for the Ante Creek Disposition.

Liquidity and Capital Resources

IBR's primary sources of cash in 2017 were the funds received from the Disposition Transaction, net proceeds from the private placement closed on September 7, 2017 and internally-generated cash flow from operating activities. The Company's net debt levels are directly related to its adjusted funds flow, capital expenditures, common share financings and acquisition and disposition activity. IBR ended the year with a working capital surplus of $21.7 million and no outstanding bank debt as compared to net debt of $0.9 million as at December 31, 2016.

	Quarter End Comparison				
($000s)	Dec. 31, 2017	Sep. 30, 2017	Jun. 30, 2017	Mar. 31, 2017	Dec. 31, 2016
Bank debt	-	33,179	29,181	20,868	-
Working capital (surplus) deficit (1)	(21,691)	3,613	(2,367)	2,233	885
Net debt (surplus)	(21,691)	36,792	26,814	23,101	885
Available-for-sale financial asset	9,000	-	-	-	-
Credit facility borrowing limit	5,000	35,000	40,000	40,000	40,000
Book capitalization (2)	333,950	334,684	333,714	333,714	333,646
Market capitalization (3)	111,861	100,172	93,632	108,734	114,737

(1) Reflects current assets (excluding non-cash risk management) plus deferred charge less current liabilities (excluding non-cash risk management).

(2) Reflects the book value of share capital, as reported on the Company's statements of financial position.

(3) Based on the market closing price of IBR's stock and the outstanding number of common shares at period-end.

On September 7, 2017, the Company closed a private placement to the directors and the new management team resulting in the issuance of 5.35 million units of the Company ("**Units**") at a purchase price of $0.60 per Unit for gross proceeds of approximately $3.2 million. Each Unit is comprised of one (1) common share and one (1) common share purchase warrant ("**Warrant**"). Each whole Warrant entitles the holder to purchase one (1) common share at a price of $0.75 per share for a period of four (4) years following the date of issuance. The Warrants vest and become exercisable in equal tranches of one-third each upon the 20-day weighted average trading price of the common shares on the TSX equalling or exceeding $0.75, $0.90 and $1.05, respectively.

As at December 31, 2017, the Company had an uncommitted demand revolving credit facility (the "**Credit Facility**") with a Canadian bank (the "**Lender**"). The maximum borrowing base limit of the Credit Facility provided by the Lender is set at $5.0 million. The Credit Facility is payable on demand and provides that advances may be made in the way of prime rate loans and letters of credit/guarantees. Prime rate loans bear interest at a rate equal to the Lender's prime rate plus 2.0% per annum.

The Credit Facility is secured by a demand debenture in the principal amount of $75.0 million with a floating charge over all assets of the Company and contains one financial covenant, an adjusted working capital ratio of at least 1:1. The adjusted working capital ratio is calculated by: dividing the summation of current assets less unrealized hedging gains plus any undrawn availability under the Credit Facility by the summation of current liabilities less unrealized hedging losses and less any current portion of bank debt. The Company was in compliance with this covenant as at December 31, 2017.

At December 31, 2017, the Company had not made any draws on the Credit Facility, but had an outstanding letter of credit of $678 thousand, as secured by the Lender, which reduced the available credit to $4.3 million. As of the date of this MD&A, the Company did not have any bank debt drawn.

Adjusted working capital bank financial covenant:

($000s)	
	December 31, 2017
Current assets	
Current assets	**29,309**
Less: unrealized hedging gains	**-**
Add: undrawn availability under the Credit Facility	**4,322**
Total current assets	**33,631**
Current liabilities	
Current liabilities	**7,618**
Less: unrealized hedging losses	**-**
Less: current portion of bank debt	**-**
Total current liabilities	**7,618**
Adjusted working capital ratio	**4.4**

LIQUIDITY ($000s)	**Year 2017**	**Year 2016**
Cash and cash equivalents, beginning of year	**404**	-
Net cash from (used in):		
Operating activities	**6,776**	32,739
Financing activities	**2,339**	(88,899)
Investing activities	**16,165**	56,564
Change in cash and cash equivalents	**25,280**	404
Cash and cash equivalents, end of year	**25,684**	404

The Company's capital resources consist primarily of cash provided from operations, available bank lines of credit and the issuance of equity. IBR's Management believes the Company will have the necessary capital resources to fund its planned 2018 capital spending program and meet working capital requirements.

The Company's objectives when managing its capital structure are to maintain an optimal capital structure in order to reduce its cost of capital, safeguard the business as a going concern, maintain financial flexibility to preserve its access to capital markets and its ability to meet financial obligations, and to finance internally-generated growth in addition to potential acquisitions. IBR manages its capital structure and makes adjustments to it in light of changes in economic conditions and the risk characteristics of its underlying assets. The Company considers its capital structure to include shareholders' equity, debt and working capital. To maintain or adjust the capital structure, IBR may from time-to-time, issue common shares, dispose of non-core assets, raise debt and/or adjust its capital spending to manage its current and projected debt levels.

Common Share and Securities Information

IBR's authorized capital consists of an unlimited number of voting common shares.

The number of common shares of the Company outstanding as at December 31, 2017 was 155.4 million, an increase of 4.4 million common shares from the balance at December 31, 2016. The increase is attributable to the private placement net of the shares cancelled pursuant to the Company's normal course issuer bid discussed hereafter.

		2017 Quarterly Comparison						
		Q417	**Q317**	**Q217**	**Q117**		**Year 2017**	**Year 2016**
TSX Share Price:	High	**$ 0.80**	$ 0.68	$ 0.84	$ 0.90		**$ 0.90**	$ 1.97
	Low	**$ 0.54**	$ 0.42	$ 0.52	$ 0.63		**$ 0.42**	$ 0.62
	Close	**$ 0.72**	$ 0.64	$ 0.62	$ 0.72		**$ 0.72**	$ 0.76
Average daily trading volume		**357,079**	251,548	291,171	452,749		**338,260**	1,562,703
Shares outstanding - period end		**155,361,864**	156,518,232	151,019,234	151,019,234		**155,361,864**	150,970,068
Weighted average basic and diluted		**156,279,364**	152,455,375	151,019,234	150,987,836		**152,699,319**	145,415,191

	TSX Trading Price Range		
2017 Monthly	**High ($)**	**Low ($)**	**Total Period Volume**
January	0.90	0.69	13,656,000
February	0.86	0.73	6,664,000
March	0.81	0.63	8,203,200
April	0.84	0.70	9,033,700
May	0.83	0.68	5,831,600
June	0.70	0.52	3,478,500
July	0.66	0.54	2,341,600
August	0.62	0.42	5,552,900
September	0.68	0.44	7,701,500
October	0.75	0.59	7,184,000
November	0.80	0.64	8,741,400
December	0.74	0.54	6,213,500

On September 7, 2017, the Company closed the aforementioned private placement, wherein a total of 5.35 million common shares of the Company were issued.

On November 20, 2017, the Company commenced a normal course issuer bid (the "**NCIB**") under which the Company may purchase for cancellation up to a maximum of 12,000,000 common shares of the Company. The NCIB will terminate on November 19, 2018 or such earlier time as the NCIB is completed or terminated at the option of the Company. For the year ended December 31, 2017, the Company purchased 1,224,702 shares for cancellation for $0.8 million. The cancelled shares have been removed from share capital. Year-to-date fiscal 2018, the Company has purchased 545,172 shares for cancellation for $0.4 million.

The following table summarizes the common shares, stock options, restricted share awards and warrants outstanding at the indicated dates:

	March 20, 2018	**December 31, 2017**	**December 31, 2016**
Common shares	**154,820,692**	**155,361,864**	150,970,068
Stock options	**10,121,000**	**9,480,500**	13,958,367
Restricted share awards	**846,167**	**777,167**	1,077,500
Warrants	**5,349,999**	**5,349,999**	-

Commitments and Contingencies

In the normal course of business, the Company has entered into various commitments that will have an impact on its future operations. These commitments primarily relate to the operating lease relating to IBR's corporate head office space, firm transportation capacity arrangements on crude oil, natural gas and NGLs sales pipeline systems and field equipment operating leases. All such commitments and obligations reflect market conditions prevailing at the time of the respective contracts and none are with related parties. IBR believes it has sufficient sources of capital to fund all commitments and obligations as they may come due.

The following table summarizes the Company's various contractual obligations and commitments as at December 31, 2017:

($000s)	2018	2019	2020	2021	2022	Thereafter	Total
Head office operating lease (1)	234	403	426	439	445	-	1,947
Oil transportation	2,032	1,220	558	165	60	132	4,167
Gas transportation	2,168	2,168	2,168	1,807	-	-	8,311
NGLs transportation	44	36	28	23	19	59	209
Field equipment	612	566	29	-	-	-	1,207
Total	5,090	4,393	3,209	2,434	524	191	15,841

(1) Pertains to lease payments associated with the Company's Calgary, Alberta head office lease, including an estimate of the Company's share of operating, utilities, property taxes and parking for the duration of the office lease.

Although the Company believes that it has title to its crude oil and natural gas properties, it cannot control or completely protect itself against the risk of title disputes or challenges.

Off-Balance Sheet Arrangements

The Company has no off-balance sheet arrangements, special purpose entities, financing partnerships or guarantees, other than as disclosed in this section. IBR has certain lease agreements, as disclosed in the aforementioned "*Commitments and Contingencies"* table, which were entered into in the normal course of business operations. All leases have been treated as operating leases or rental arrangements whereby the lease payments are included in operating expenses or G&A expenses depending on the nature of the lease. No asset or liability value has been assigned to these leases on the statement of financial position as at December 31, 2017.

Disclosure Controls and Procedures and Internal Controls Over Financial Reporting

IBR's disclosure controls and procedures ("**DC&P**"), as defined in National Instrument ("**NI**") 52-109 "*Certification of Disclosure in Issuers' Annual and Interim Filings*", have been designed by the Company's Chief Executive Officer ("**CEO**") and Chief Financial Officer ("**CFO**"), or caused to be designed under their supervision, to provide reasonable assurance that information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in the securities legislation and include controls and procedures designed to ensure that information required to be disclosed by IBR in its annual filings, interim filings or other reports filed or submitted under securities legislation is accumulated and communicated to the Company's management, including its certifying officers, as appropriate to allow timely decisions regarding required disclosure. Such certifying officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Company's disclosure controls and procedures at the financial year end of the Company and have concluded that the Company's disclosure controls and procedures are effective at the financial year end of the Company for the foregoing purposes.

Additionally, pursuant to NI 52-109, the Company's CEO and CFO are responsible for designing and evaluating the internal controls over financial reporting ("**ICOFR**") or causing them to be designed or evaluated under their supervision. ICOFR is a process designed to provide reasonable assurance that all assets are safeguarded, transactions are appropriately authorized and to facilitate the preparation of relevant, reliable and timely information resulting in the preparation of financial statements for external purposes which are in accordance with IFRS. Utilizing the Committee of Sponsoring Organizations of the Treadway Commission ("**COSO**") Internal Control – Integrated Framework (2013), such certifying officers have evaluated, or caused to be evaluated under their supervision, the design and operating effectiveness of the Company's internal controls over financial reporting at the financial year end of the Company and concluded that the Company's internal controls over financial reporting are designed property and operating effectively, at the financial year end of the Company, for the foregoing purpose. The Company is required to disclose herein any change in the Company's internal controls over financial reporting that occurred during the period beginning on October 1, 2017 and ended on December 31, 2017 that has materially affected, or is reasonably likely to materially affect, the Company's internal controls over financial reporting. No material changes in the Company's internal controls over financial reporting were identified during such period that have materially affected, or are reasonably like to materially affect, the Company's internal controls over financial reporting.

Control systems, no matter how well designed, have inherent limitations. Moreover, any control system, no matter how well conceived or operated, can provide only reasonable, not absolute assurance, that the objectives of the control system are met and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud.

Use of Estimates and Judgments

The preparation of consolidated financial statements in conformity with IFRS requires IBR's management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amount of assets, liabilities, income and expenses. Actual results may differ materially from these estimates.

Estimates and their underlying assumptions are reviewed on an ongoing basis and are based on the Company's management's experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances. Revisions to accounting estimates are recognized in the year in which the estimates are revised and for any future years affected.

Critical Judgments in Applying Accounting Policies

The following are critical judgments that management has made in the process of applying accounting policies and that have the most significant effect on the amounts recognized in the consolidated financial statements.

The Company's assets are aggregated into cash generating units for the purpose of calculating impairment. Cash generating units ("**CGU**" or "**CGUs**") are based on an assessment of the unit's ability to generate independent cash inflows. The determination of these CGUs was based on management's judgment in regards to geographical proximity, geological and production profile, shared infrastructure and similar exposure to market risk and materiality. Based on this assessment, the Company's CGUs are generally composed of significant development areas. The Company reviews the composition of its CGUs at each reporting date to assess whether any changes are required in light of new facts and circumstances.

Judgments are required to assess when impairment indicators exist and impairment testing is required. In determining the recoverable amount of assets, in the absence of quoted market prices, impairment tests are based on estimates of proved and/or probable reserves, production rates, future crude oil and natural gas prices, future costs, discount rates, market value of land and other relevant assumptions.

The application of the Company's accounting policy for exploration and evaluation assets requires management to make certain judgments as to future events and circumstances as to whether economic quantities of reserves have been found.

Judgments are made by management to determine the likelihood of whether deferred tax assets at the end of the reporting period will be realized from future taxable earnings.

Key Sources of Estimation Uncertainty

The following are key estimates and their assumptions made by management affecting the measurement of balances and transactions in these consolidated financial statements.

Estimation of recoverable quantities of proved and probable reserves include estimates and assumptions regarding future commodity prices, foreign currency exchange rates, discount rates and operating and transportation costs for future cash flows. It also requires the interpretation of complex geological and geophysical models in order to make an assessment of the size, shape, depth and quality of reservoirs, and their anticipated recoveries of reserves. The economic, geological and geophysical, and other technical factors used to estimate proved plus probable reserves may change from period to period. Changes in reported reserves can affect the non-cash impairment of assets, the provision for decommissioning obligations, the economic feasibility of exploration and evaluation assets, the recognition of deferred tax assets and the amounts reported for depletion and depreciation of property, plant and equipment. These reserve estimates are prepared in accordance with the *Canadian Oil and Gas Evaluation Handbook* by independent qualified reserves engineers, who work with information provided by the Company to establish reserve determinations based on the guidance stipulated by National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities.*

The Company estimates the decommissioning obligations for crude oil and natural gas wells and their associated production facilities. In most instances, removal of assets and remediation occurs many years into the future. Amounts recorded for the decommissioning obligations and related accretion expense require assumptions regarding removal date, future environmental legislation, the extent of reclamation activities required, the engineering methodology for estimating cost, inflation estimates, future removal technologies in determining the removal cost, and the estimate of the liability specific discount rates to determine the present value of these cash flows.

In a business combination, management makes estimates of the fair value of assets acquired and liabilities assumed which includes assessing the value of crude oil and natural gas properties based upon the estimation of recoverable quantities of proved and probable reserves being acquired.

The Company's estimate of the depletion and depreciation of property, plant and equipment is based on estimates of proved and probable reserves and the associated future development costs.

The Company's estimate of non-cash share-based compensation is dependent upon estimates of historic stock price trading volatility, interest rates, expected terms to exercise and forfeiture rates.

The Company's estimate of the fair value of derivative financial instruments is dependent on estimated forward crude oil and natural gas prices, expected interest rates, expected future foreign currency exchange rates and expected volatility in these variables.

The deferred tax asset or liability is based on estimates as to the timing of the reversal of temporary differences, substantively enacted tax rates and the likelihood of assets being realized.

Accounting Pronouncements

The following pronouncements from the International Accounting Standards Board ("**IASB**") will become effective for financial reporting periods beginning on or after January 1, 2018 and have not yet been adopted by the Company. These new or revised standards permit early adoption with transitional arrangements depending upon the date of initial application:

- IFRS 15 – "*Revenue from Contracts with Customers*" contains a single model that applies to contracts with customers and two approaches to recognizing revenue: at a point in time or over time. The model features a contract-based five-step analysis of transactions to determine whether, how much and when revenue is recognized. New estimates and judgmental thresholds have been introduced, which may affect the amount and/or timing of revenue recognized. The new standard is effective for annual periods beginning on or after January 1, 2018.

  The Company will adopt IFRS 15 on January 1, 2018 using the modified retrospective approach. The Company is still in the process of reviewing its contracts with customers and completing its assessment of various revenue; however, at this time, the Company does not foresee the standard having a material impact on net loss and financial position. The Company will expand its disclosures in the notes to the financial statements as prescribed by IFRS 15, including disclosing the disaggregated revenue streams by product type.

- IFRS 9 – "*Financial Instruments"* addresses the classification and measurement of financial assets, and is the first step to replace IAS 39 – *"Financial Instruments: Recognition and Measurement."* IFRS 9 uses a single approach to determine whether a financial asset is measured at amortized cost or fair value, replacing the multiple rules in IAS 39. The single approach in IFRS 9 is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. IFRS 9 also requires a single impairment method to be used, replacing the multiple methods in IAS 39. The mandatory effective date of IFRS 9 is for annual periods beginning on or after January 1, 2018 and must be applied retrospectively with some exemptions.

The Company does not apply hedge accounting nor does it intend to apply hedge accounting to any of its risk management contracts, if outstanding, upon the adoption of IFRS 9. The Company is still in the process of reviewing its financial instruments and completing its assessment of the impact of IFRS 9; however, at this time, the Company does not foresee the standard having a material impact on net loss and financial position.

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

  The Company is in the early stages of assessing the impact of IFRS 16, including identifying and examining the contracts affected by the new standard. The extent of the impact upon the Company's financial statements has not yet been determined.

Other Information

Oil Equivalent Conversions

In this MD&A, production and reserves data is commonly stated in barrels of oil equivalent using a six (6) to one (1) conversion ratio when converting thousands of cubic feet of natural gas to barrels of oil and a one-to-one conversion ratio for natural gas liquids. Such conversion may be misleading, particularly if used in isolation. An oil equivalent conversion ratio of six (6) Mcf: one (1) Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Forward-Looking Statements

Certain information regarding the Company contained herein may constitute forward-looking statements within the meaning of applicable securities laws. Forward-looking statements may include estimates, plans, expectations, intentions, opinions, forecasts, projections, anticipates, guidance or other similar statements that are not statements of fact. Although IBR believes that the expectations reflected in such forward-looking statements are reasonable, it can give no assurance that such expectations will prove to be correct. These statements are subject to certain risks and uncertainties and may be based on assumptions that could cause actual results to differ materially from those anticipated or implied in the forward-looking statements. The Company's forward-looking statements are expressly qualified in their entirety by this cautionary statement.

These forward-looking statements are subject to numerous risks and uncertainties, certain of which are beyond IBR's control, including but not limited to the following: the impact of general economic conditions; volatility in market prices for crude oil, natural gas and NGLs; general industry and broader market conditions; foreign exchange currency fluctuation; imprecision of proved and/or probable reserve estimates; liabilities inherent in crude oil and natural gas operations; environmental risks; incorrect assessments of the value of acquisitions and exploration and development programs; competition from other crude oil and natural gas producers; the lack of availability of qualified personnel or management; changes in income tax laws or changes in tax laws and incentive programs relating to the crude oil and natural gas industry; hazards such as fire, explosion, blowouts and spills, each of which could result in substantial damage to wells, production facilities, other property and the environment or in personal injury; stock market volatility; ability to access sufficient capital from internal and external sources; greenhouse gas emissions and carbon tax levy legislation, and the other risks and uncertainties outlined in IBR's Annual Information Form for the year ended December 31, 2017.

Non-GAAP Measures

Throughout this MD&A, the Company uses non-GAAP measures as an indicator of the Company's performance. These non-GAAP measures are not prescribed by IFRS and do not have standardized meanings or methods of calculation and therefore, such measures may not be comparable to similar measures presented by other companies.

Adjusted Funds Flow

As an indicator of the Company's performance, the term *adjusted funds flow* contained within the MD&A should not be considered as an alternative to, or more meaningful than, cash provided from (used in) operating, financing or investing activities, as determined in accordance with IFRS. *Adjusted funds flow* is widely accepted as a financial indicator of an exploration and production company's ability to generate cash which is used to internally fund exploration and development capital activities and to service debt. This measure is widely used by shareholders and investors in the valuation, comparison and investment recommendations of companies within the upstream oil and gas exploration and production industry.

Adjusted funds flow, as disclosed within this MD&A, represents cash provided from (used in) operating activities before: decommissioning obligation cash expenditures, changes in non-cash working capital from operating activities and non-cash changes in deferred charge. The Company presents cash provided from operating activities per share and *adjusted funds flow* per share whereby per share amounts are calculated consistent with the calculation of net income per share.

The following table reconciles IBR's cash provided from operating activities to *adjusted funds flow*:

($000s)	Quarterly Comparison						
	Q417	**Q317**	**Q217**	**Q117**	**Q416**	**Year 2017**	**Year 2016**
Cash provided from (used in) operating activities	**4,534**	(2,659)	1, 669	3,232	4,984	**6,776**	32,739
Decommissioning expenditures	**-**	60	-	-	2	**60**	186
Change in non-cash working capital from operating activities and deferred charge	**(4,921)**	(694)	1,134	(834)	(1,613)	**(5,315)**	(3,341)
Adjusted funds flow	**(387)**	(3,293)	2,803	2,398	3,373	**1,521**	29,584

Net Operating Expenses

Net operating expenses are calculated as operating expenses less the component of other income pertaining to gathering, compression, road use and other income. This metric is expressed on a total and per boe basis. Management uses this metric to determine the net cash cost related to operating expenses and to provide supplemental information to analyze operating performance.

Net Transportation Expenses

Net transportation expenses are calculated as transportation expenses less the component of other income pertaining to transportation income. This metric is expressed on a total and per boe basis. Management uses this metric to determine the net cash cost related to transportation expenses and to provide supplemental information to analyze operating performance.

Operating Netback

Operating netback refers to realized revenue (including realized gains or losses on commodity risk management contracts) less royalties, *net operating expenses* and *net transportation expenses* on a total and per boe basis. The Company believes this financial netback measure is useful supplemental information to analyze operating performance and to provide an indication of the results generated by the Company's principal business activities.

Total Net Debt-to-Annualized Adjusted Funds Flow

The Company monitors its capital structure based on a non-IFRS financial metric consisting of the ratio of *total net debt*-to-annualized *adjusted funds flow*. *Total net debt* and/or *net debt* as disclosed within the MD&A, represents outstanding bank debt less deferred charge plus working capital deficiency (or minus working capital surplus) excluding unrealized amounts pertaining to risk management contracts.

Abbreviations

The following are abbreviations that are contained within this MD&A commentary:

Crude Oil and Natural Gas Liquids		**Natural Gas**	
Bbl	barrel	Mcf	thousand cubic feet
boe	barrels of oil equivalent	Mcf/d	thousand cubic feet per day
Mboe	thousand barrels of oil equivalent	MMbtu	million British Thermal Units
Bbls/d	barrels per day	GJ	gigajoule
boe/d	barrels of oil equivalent per day	GJs/d	gigajoules per day
NGLs	natural gas liquids	kW	kilowatt

Business Risks and Uncertainties

The Company's exploration and development activities are focused in the Western Canada Sedimentary Basin within the province of Alberta, which is characterized as being highly competitive with competitors varying in size from small junior producers to significantly larger and fully-integrated energy companies possessing greater financial and personnel resources. In the normal course of business, IBR is exposed to a variety of business risks and uncertainties that can have an effect on its financial condition.

The Company recognizes certain risks inherent in the oil and gas industry, such as access to oil and gas services, weather-related delays with drilling and operational plans, finding and developing crude oil and natural gas reserves at economic costs, drilling risks, producing crude oil and natural gas in commercial quantities, environmental and safety risks, and commodity price and political risks and uncertainties. IBR has engaged professional senior management and seasoned technical personnel, possessing many years of experience in the oil and gas business and intellectual capacity, to address, prudently manage and mitigate these risks. Please see the Company's website to reference the backgrounds and qualifications of IBR's senior leadership team, which can be sourced at www.ironbridgeres.com.