Date - The following Management's Discussion and Analysis ("MD&A") of Edge Resources Inc. (the "Company" or "Edge") as at and for the years ended March 31, 2015 and 2014 has been prepared by management taking into consideration information available to June 29, 2015 and should be read in conjunction with the Company's audited financial statements as at and for the years ended March 31, 2015 and 2014 and the related notes.

Business Description – The Company is focused on the exploration, development and production of shallow oil and natural gas horizons. The Company is a junior oil and gas company that is listed under the symbol "EDE" on the TSX Venture Exchange ("TSXV") and "EDG" on the Alternative Investment Market of the London Stock Exchange ("AIM"). Additional information relating to Edge, including Edge's financial statements can be found on SEDAR at www.sedar.com or the Company's website at www.edgeres.com.

Basis of Presentation - The financial data presented herein has been prepared in accordance with International Financial Reporting Standards ("IFRS").The reporting and measurement currency is the Canadian dollar.

Non-GAAP Measures - Certain measures in this document do not have any standardized meaning as prescribed by IFRS such as "field netback", and "net debt", and therefore are considered non-GAAP measures. Field netback is calculated as the net of oil and natural gas sales, royalties, operating costs, and transportation costs and is calculated in the table on page 4. Field netback is presented in this report to assist users in determining the profitability of field level operations. Net debt is calculated as current assets minus current liabilities excluding derivative instruments (if any) and is presented in table at the end of the 'Liquidity and Capital Resources' section of the MD&A. Net debt is presented to allow users to understand the amount of revolving credit facility availability remaining to the Company.

Additional GAAP Measures - In addition, this MD&A contains the term "funds flow from operations" or "funds flow" which is based on cash flow from operating activities (as determined under IFRS) before changes in non-cash items and expenditures on decommissioning liabilities (if any). The Company also presents funds flow from operations per share whereby per share amounts are calculated using weighted average shares outstanding consistent with the calculation of earnings per share. Management uses funds flow from operations to analyze operating performance and considers funds flow from operations to be a key measure as it demonstrates the Company's ability to generate the cash necessary to fund future capital investment and to repay debt. Funds flow from operations is reconciled to its nearest GAAP equivalent, "net cash generated from (used in) operating activities" at the bottom of the table on page 4.

Readers are cautioned, however, that these non-GAAP and additional GAAP measures should not be construed as alternatives to other terms such as current or long-term debt, net income and cash flows from operating activities determined in accordance with IFRS as measures of performance. Edge's method of calculating these measures may differ from other companies, and accordingly, may not be comparable to similar measures used by other companies.

BOE Conversions - The calculation of barrels of oil equivalent ("boe") is based on a conversion ratio of 6,000 cubic feet of natural gas to 1 barrel of oil to estimate relative energy content and does not represent a value equivalency at the wellhead. Boe's may be misleading, particularly if used in isolation. A boe conversion is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. This conversion conforms to the Canadian Securities Regulator's National Instrument 51-101, *Standards of Disclosure for Oil and Gas Activities*. These terms are not defined by IFRS and are therefore referred to as non-GAAP measures.

OUTLOOK

Edge has remained true to its strategy of operating in a conventional, shallow arena with properties that offer exceptionally large economic returns at lower than average risk, regardless of the commodity type. With much industry attention now focused on lower and decreasing oil prices, our dedication to an excellent strategy and the assembly of exceptionally high quality assets will allow Edge to excel during a an industry downturn. Within the context of a tumultuous industry dynamic, Edge has acted very conservatively with respect to capital expenditures and cost management, and will continue to do so while commodity prices remain low and/or unstable.

Commodity price swings affect the top line; however, heavy oil producers should consider other important factors, such as managing costs. In the midst of falling WTI oil prices, Edge's received heavy oil price has had some reprieve, as the "heavy oil discount" to WTI has dramatically improved during the same period. Additionally, the Canadian dollar has weakened versus the US dollar during this time resulting in a lower oil pricing impact for Canadian producers. Both of these factors have lessened the impact of falling light oil prices on Canadian heavy oil producers.

The heavy oil wells continue to produce prolifically at rates near or over 100 bopd, more than one year later. Edge's geological and seismic models, updated with information from actual wells drilled, have uncovered additional previously undiscovered oil pools on the Company's 100%-owned land in the municipality of Eye Hill, Saskatchewan. The Company expects that it could drill dozens of additional developmental wells on this property. Corporate drilling plans will be focused on the low-risk, high-return opportunities offered on our Saskatchewan land-base. Building on Edge's past successful drilling in the area, management will continue to utilize the tactics that have led to the Company's success and apply the operational and technical expertise to the existing portfolio of oil properties. The Company is unlikely to employ a large drilling program in the near future, given the low oil price. Efforts will be focused more on the acquisition of additional, complimentary assets and/or corporations.

The Company has demonstrated a consistent record of highly successful and accretive acquisitions – especially for a junior E&P company in the midst of an illiquid equity market. While the bulk of value has traditionally been created with the drill bit, it is reasonable to expect that opportunities for additional acquisitions will present themselves in the future.

The Company has secured significant debt facilities, enjoyed successful drilling results that improved cash flows and has established a proven ability to raise equity from strong institutional relationships and partnerships, all of which should allow continual measured growth.

In any endeavor we pursue, whether through the drill bit or via acquisition; oil or gas; vertical or horizontal; deep or shallow, at the core of that pursuit will be maintaining the fundamentals that have brought us success in the past:

1. High capital efficiencies and recycle ratios (> 2.5x recycle ratio)
2. Fast payback on capital invested (< 12 months)

OPERATING AND FINANCIAL SUMMARY

For the year ended March 31, 2015:

- Sales volumes remained consistent at 565 boe/d compared to 555 boe/d in the prior year as increased oil production volumes were offset with decreased natural gas volumes.
- Major capital activity included
    - Downhole optimization of 3 gross (3 net) oil wells in Eye Hill
    - Installation of natural gas and water handling infrastructure in Eye Hill
- Due to continued low commodity prices the Company recorded an impairment loss (included as additional depletion expense) for its Willesden Green natural gas cash generating unit of $11.2 million.
- The Company changed its bank debt lender during the year, resulting in a more stable and economically enhanced lending situation.
- The Company decommissioned a natural gas rental compressor in the Willesden Green area in November 2014, which reduced and will continue to reduce natural gas operating costs.

For the three months ended March 31, 2015:

- Sales volumes were 612 boe/d compared to 569 boe/d in the third quarter of fiscal 2015 and 618 boe/d in the fourth quarter of fiscal 2014; the increase from the prior quarter is due primarily to the added gas volumes being sold on completion of the natural gas infrastructure in Eye Hill.
- Due to continued low commodity prices the Company recorded an impairment loss this quarter (included as additional depletion expense) for its Willesden Green natural gas cash generating unit of $6.8 million ($4.4 million was recorded in the previous quarter for a total of $11.2 million for the year).
- Due to the installation of natural gas and water handling facilities in Eye Hill in December 2014, the Company has significantly reduced operating costs during the quarter.

SUMMARY OF QUARTERLY AND YEAR-TO-DATE RESULTS:

	Three months ended March 31,		Twelve months ended March 31,	
	2015	2014	2015	2014
Financial *($000's except per share data)*				
Oil and natural gas sales	1,697	3,189	10,136	10,008
Funds flow from (used in) operations	132	293	1,418	815
Per share – basic and diluted	0.00	0.00	0.01	0.01
Net loss	(7,513)	(625)	(11,458)	(1,704)
Per share – basic and diluted	(0.05)	(0.00)	(0.07)	(0.01)
General & administrative	440	456	1,791	1,873
Property expenditures, net of dispositions*	678	143	2,798	3,686
Working capital deficit			(7,723)	(7,531)
Shareholders' equity			3,259	14,423
Total assets			31,491	39,370
Operating *(average daily production)*				
Oil and natural gas liquids (bbls/d)	401	350	354	291
Natural gas (mcf/d)	1,268	1,608	1,270	1,587
Equivalent barrels (boe/d)	612	618	565	555

* relates to expenditures on property and equipment, acquisitions and exploration and evaluation assets

OPERATIONAL AND FUNDS FLOW SUMMARY FOR THE QUARTER AND YEARS ENDED MARCH 31, 2015 AND 2014:

	Three months ended March 31,				Twelve months ended March 31,			
$000s	2015		2014		2015		2014	
Volumes								
Oil and natural gas liquids (bbls/d)		401		350		354		291
Natural gas (mcf/d)		1,268		1,608		1,270		1,587
Total (boe/d)		612		618		565		555
Natural gas field netback	$	$/mcf	$	$/mcf	$	$/mcf	$	$/mcf
Sales	168	2.51	806	5.50	1,649	3.98	2,409	3.91
Royalties	(32)	(0.47)	(128)	(0.87)	(172)	(0.42)	(356)	(0.58)
Operating costs	(205)	(3.07)	(413)	(2.82)	(1,271)	(3.07)	(1,488)	(2.41)
Transportation costs	(12)	(0.19)	(37)	(0.25)	(104)	(0.25)	(133)	(0.21)
Natural gas netback	(81)	(1.22)	228	1.56	102	0.24	432	0.71
Handling income	3	0.05	11	0.08	31	0.07	50	0.08
Gas field netback	(78)	(1.17)	239	1.64	133	0.31	482	0.79
Oil field netback	$	$/bbl	$	$/bbl	$	$/bbl	$	$/bbl
Sales	1,529	34.29	2,383	76.41	8,487	61.82	7,599	75.99
Royalties	(233)	(5.23)	(482)	(15.44)	(1,672)	(12.18)	(1,386)	(13.86)
Operating costs	(534)	(11.98)	(702)	(22.50)	(2,174)	(15.83)	(2,153)	(21.53)
Transportation costs	(94)	(2.10)	(83)	(2.68)	(321)	(2.34)	(242)	(2.42)
Oil field netback	668	14.97	1,116	35.79	4,320	31.47	3,818	38.18
Total field netback	$	$/boe	$	$/boe	$	$/boe	$	$/boe
Oil and natural gas sales	1,697	30.46	3,189	57.34	10,136	49.13	10,008	49.37
Royalties	(265)	(4.75)	(610)	(10.96)	(1,844)	(8.94)	(1,742)	(8.59)
Operating costs	(739)	(13.26)	(1,115)	(20.05)	(3,445)	(16.70)	(3,641)	(17.96)
Transportation costs	(106)	(1.91)	(120)	(2.15)	(425)	(2.06)	(375)	(1.85)
Total field netback	587	10.54	1,344	24.18	4,422	21.43	4,250	20.97
Handling income	3	0.06	11	0.20	31	0.15	50	0.25
Total field netback	590	10.60	1,355	24.38	4,453	21.58	4,300	21.22
General and administrative	(440)	(7.89)	(455)	(8.17)	(1,791)	(8.68)	(1,873)	(9.25)
Finance (cash only)	(262)	(4.71)	(281)	(5.06)	(1,149)	(5.57)	(1,143)	(5.64)
Realized gain (loss) on derivatives	264	4.74	(291)	(5.24)	19	0.09	(431)	(2.13)
Capital taxes	(20)	(0.36)	(35)	(0.62)	(114)	(0.55)	(38)	(0.19)
Funds flow from (used in) operations	132	2.38	293	5.29	1,418	6.87	815	4.01
Decommissioning expenditures	-	-	-	-	(291)	(1.41)	-	-
Change in non-cash items	281	5.04	93	1.66	1,091	5.29	472	2.33
Cash generated from operating activities	413	7.42	386	6.95	2,218	10.75	1,287	6.34

OIL AND NATURAL GAS SALES

Oil and natural gas sales for the three month period ended March 31, 2015 as compared to the comparable period last year have decreased due to decreased pricing for both oil and natural gas in the current period.

Oil and natural gas sales for the year ended March 31, 2015 have remained consistent with last year because both production and pricing on a per boe basis remained consistent in each year.

Oil pricing subsequent to March 31, 2015 has increased marginally and therefore the Company is expecting that sales may increase subject to actual production volumes.

ROYALTIES

	Three months ended March 31,		Twelve months ended March 31,	
$000s	2015	2014	2015	2014
Royalty breakdown				
Natural gas	32	128	172	356
Oil	233	482	1,672	1,386
Total royalties	265	610	1,844	1,742
% of revenue	16%	19%	18%	17%

Natural gas and oil royalties on an absolute basis and percentage of revenue basis for the three month period ended March 31, 2015 have decreased from the comparable prior period due to significantly lower commodity prices in the current period.

Natural gas royalties on absolute basis for the year ended March 31, 2015 have decreased from the prior year due to decreased in production volumes in the current period.

Oil royalties on absolute basis for the year ended March 31, 2015 have increased from last year due to an increase in production volumes in the current year.

Royalties for the year ended March 31, 2015 as a percentage of revenue have remained consistent with the prior year because production rates and pricing were consistent in each year.

The Company expects future royalty rates may increase slightly due to the moderate increase in world oil pricing subsequent to March 31, 2015 however that is subject to actual production rates.

OPERATING AND TRANSPORTATION EXPENSES

	Three months ended March 31,				Twelve months ended March 31,			
$000s	2015		2014		2015		2014	
Natural gas costs	$	$/mcf	$	$/mcf	$	$/mcf	$	$/mcf
Operating costs	205	3.07	413	2.82	1,271	3.07	1,488	2.41
Transportation costs	12	0.19	37	0.25	104	0.25	133	0.21
Total	217	3.26	450	3.07	1,375	3.32	1,621	2.62
Oil costs	$	$/boe	$	$/boe	$	$/boe	$	$/boe
Operating costs	534	11.98	702	22.50	2,174	15.83	2,153	21.53
Transportation costs	94	2.10	83	2.68	321	2.34	242	2.42
Total	628	14.08	785	25.18	2,495	18.17	2,395	23.95
Total costs	$	$/boe	$	$/boe	$	$/boe	$	$/boe
Operating costs	739	13.26	1,115	20.05	3,445	16.70	3,641	17.96
Transportation costs	106	1.91	120	2.15	425	2.06	375	1.85
Total	845	15.17	1,235	22.20	3,870	18.76	4,016	19.81

Operating and transportation costs on an absolute and per boe basis for the three month period and year ended March 31, 2015 have decreased compared to the prior periods mainly because the Company has offset increasing per boe natural gas costs (due to declining natural gas production volumes subject to relatively high fixed costs) with decreasing per boe oil costs (due to increased production volumes per oil well and reduced water handling costs as a result of the commencement of operation of its water injection facility in Eye Hill).

Future operating costs on a per barrel basis are expected to be consistent with the current quarter.

OTHER INCOME

Other income results from revenues generated from third parties using the Company's wholly owned gas transportation infrastructure in the Willesden Green area. For the three month period and year ended March 31, 2015, the revenues decreased compared to the comparable prior periods due to lower third party volumes using the Company's infrastructure.

FIELD NETBACKS

Natural gas netbacks on a per boe and absolute basis and for the three month period and year ended March 31, 2015 have decreased from the comparable prior periods due mainly to decreased production volumes and higher fixed costs on a per boe basis in the current periods.

Despite having increased oil production volumes for the three month period ended March 31, 2015, absolute and per boe netbacks decreased from the comparable prior period mainly due to significantly lower oil prices. Oil netbacks on an absolute basis for the year ended March 31, 2015 have increased from the prior year mainly due to increased production volumes; however the netback on a per boe basis has declined due to lower oil prices in the current year.

The Company expects future corporate near-term netbacks to improve slightly from the current quarter due to an improvement in world oil prices subsequent to March 31, 2015.

GENERAL AND ADMINISTRATIVE ("G&A") EXPENSES

	Three months ended March 31,				Twelve months ended March 31,			
$000s	2015		2014		2015		2014	
	$	$/boe	$	$/boe	$	$/boe	$	$/boe
Regular G&A expenses	440	7.89	463	8.32	1,810	8.77	1,902	9.39
Recoveries	-	-	(8)	(0.15)	(19)	(0.09)	(29)	(0.14)
Total G&A expenses	440	7.89	455	8.17	1,791	8.68	1,873	9.25

Regular G&A expenses on an absolute basis for the three month period and year ended March 31, 2015 have decreased with the comparable prior periods due to continued efforts by the Company to reduce costs during the oil price downturn.

Near term future G&A costs on an absolute basis are expected to be slightly lower than the current quarter due to slightly reduced staffing levels. The Company is actively considering and may implement various strategies to reduce future G&A costs even further if world oil pricing remains at current low levels.

FINANCE EXPENSES (CASH COSTS)

For the three month period and year ended March 31, 2015 compared to the comparable prior periods, finance costs have remained consistent because although the interest rate was lower on its bank debt (as a result of changing lenders during the year) and loans payable, debt balances were slightly higher during the current periods.

Finance costs are expected to increase slightly in the future due to slightly increased expected debt levels.

REALIZED GAIN (LOSS) ON DERIVATIVES

Lower actual product pricing compared to contracted rates resulted in a gain during the three month period and year ended March 31, 2015 as opposed to a loss during the comparable prior periods.

CAPITAL TAXES

The capital tax expense results from a 1.7% provincial government charge on the Company's Saskatchewan gross revenues. Capital taxes for the three month period ended March 31, 2015 are lower compared to the comparable prior period due to lower overall gross revenue in Saskatchewan during the current period. Capital taxes for the year ended March 31, 2015, have increased from the prior year due to; increased gross revenue in the current year in Saskatchewan, and the previous year includes a recovery related to overpayments made for the previous year.

DECOMMISSIONING EXPENDITURES

The Company decommissioned its underutilized natural gas rental compressor in its Willesden Green area, resulting in a $290,000 expenditure during the year ended March 31, 2015. There were no decommissioning expenditures during the comparable prior period.

CASH GENERATED FROM OPERATING ACTIVITIES

	Three months ended March 31,		Twelve months ended March 31,	
$000s	2015	2014	2015	2014
Funds flow from operations	132	293	1,418	815
Decommissioning expenditures	-	-	(291)	-
Change in non-cash items	281	93	1,091	472
Cash generated from operating activities	413	386	2,218	1,287
Funds flow from operations per share				
- basic and diluted	0.00	0.00	0.01	0.01
Cash generated from operating activities per share				
- basic and diluted	0.00	0.00	0.01	0.01

Funds flow from operations decreased during the three month period ended March 31, 2015 compared to the comparable prior period due mainly to a significant decrease in product pricing in the current quarter.

Funds flow from operations increased during the year ended ended March 31, 2015 compared to the prior year due mainly to decreased derivatives losses in the current year.

The Company expects near term future funds flows from operations to be consistent with the current quarter subject to actual production levels.

DEPLETION AND DEPRECIATION

	Three months ended March 31,				Twelve months ended March 31,			
	2015		2014		2015		2014	
$000s	$	$/boe	$	$/boe	$	$/boe	$	$/boe
Depletion and depreciation	495	8.89	472	8.49	1,860	9.01	1,972	9.73
Impairment	6,800	122.07	-	-	11,200	54.29	-	-
Total depletion and depreciation	7,295	130.96	472	8.49	13,060	63.30	1,972	9.73

For the three month period and year ended March 31, 2015 as compared to the comparable prior periods, depletion and depreciation on an absolute basis and per boe basis has remained consistent due to relatively similar production rates and per boe carrying costs in all the periods.

The Company recorded an impairment loss of $11.2 million on its Willesden Green natural gas cost-generating unit during the year-ended March 31, 2015 ($4.4 million as at December 31, 2014 and $6.8 million as at March 31, 2015). The impairment was due to a significant decrease in the forecast natural gas prices at December 31, 2014 and March 31, 2015 as compared to March 31, 2014.

Subject to the Company's future drilling results (if any), management expects depletion and depreciation on a per boe and an absolute basis to remain consistent with the current quarter.

STOCK-BASED COMPENSATION

	Three months ended March 31,		Twelve months ended March 31,	
$000s	2015	2014	2015	2014
Stock-based compensation	57	70	283	327

Stock-based compensation represents the non-cash expense associated with issuing stock options, and is generally recognized over the vesting period of the options.

Stock-based compensation expense for the three month period and year ended March 31, 2015 decreased from the comparable prior periods because fewer options with lower calculated values vested during the current periods.

EXPLORATION AND EVALUATION EXPENDITURES

These amounts represent previously capitalized costs for certain expired lands and discontinued projects and are expected to continue to be relatively insignificant for the Company.

UNREALIZED GAIN ON FINANCIAL DERIVATIVES

	Three months ended March 31,		Twelve months ended March 31,	
$000s	2015	2014	2015	2014
Unrealized gain (loss)	(247)	(330)	667	(354)

The unrealized gains (losses) in the above periods represents; a) the reversal of previously recorded unrealized fair value of derivative instruments for the period that becomes realized, b) the revaluation of the estimated fair value of the remaining contracts as at the period end, and c) the recognition of a fair value for any new contracts that may have been entered into during the period.

For the three month period ended March 31, 2015, the loss decreased from the comparable prior period mainly because there were fewer volumes under contract at the end of the current period. For the year ended March 31, 2015 there is a gain as opposed to a loss in the prior year mainly because there were fewer volumes under contract at the end of the current year.

The actual amounts realized under these derivative contracts is subject to how the actual future pricing of the applicable commodities moves in relation to the price established by the Company under the derivative contracts.

GAIN ON DISPOSITION OF OIL AND NATURAL GAS INTERESTS

On May 15, 2013, the Company completed an asset swap transaction with an unrelated third party such that $200,000 of oil and natural gas interests were swapped for $200,000 of undeveloped lands. The carrying amount of the oil and natural gas interests was $15,000, including a decommissioning provision of $40,000, resulting in a gain on sale of $185,000 for the year ended March 31, 2014.

LOSS ON SETTLEMENT OF DECOMMISSIONING PROVISION

During the year ended March 31, 2015, the Company decommissioned its underutilized natural gas compressor in the Willesden Green area for a total of $290k, which had a decommissioning provision of $262k at the time, resulting in a $28k loss.

FINANCE EXPENSES (NON-CASH)

	Three months ended March 31,		Twelve months ended March 31,	
$000s	2015	2014	2015	2014
Accretion	46	45	172	156

Included in finance expenses is the non-cash amount to accrete the Company's currently recognized decommissioning liability up to the estimated future amount. The current amounts have remained relatively consistent with prior periods because the Company had similar amounts of wells and facilities in each period.

INCOME TAXES

	Three months ended March 31,		Twelve months ended March 31,	
$000s	2015	2014	2015	2014
Deferred tax recovery	-	-	-	116

The non-cash recovery in the previous year results from the Company spending amounts related to flow-through shares issued and will vary based on both the amount of flow-through equity raised and the timing of spending on qualified projects.

The Company has approximately $7.1 million in deferred tax assets as at March 31, 2015, which have not been recognized in the financial statements.

The Company has existing tax losses and resource tax pools of approximately $49 million as of March 31, 2015.

LOSS

	Three months ended March 31,		Twelve months ended March 31,	
$000s	2015	2014	2015	2014
Loss and comprehensive loss	(7,513)	(625)	(11,458)	(1,704)
Loss and comprehensive loss per share - basic and diluted	(0.05)	(0.00)	(0.07)	(0.01)

The loss for the three month period and year ended March 31, 2015 has increased compared to the comparable previous periods because of the impairment charges recorded during the current periods.

The Company expects losses to continue in the near term given the continued weakness in world oil prices subsequent to March 31, 2015.

SELECTED QUARTERLY INFORMATION

The following table sets forth certain quarterly financial information of the Company's previous quarters:

$000s	Q4 2015	Q3 2015	Q2 2015	Q1 2015	Q4 2014	Q3 2014	Q2 2014	Q1 2014
Average production (boe/d)	612	569	474	613	618	491	538	577
Oil and natural gas sales	1,697	2,608	2,357	3,474	3,189	1,932	2,566	2,321
Operating netback ($/boe)	10.60	21.21	22.68	32.04	24.18	15.50	24.75	19.46
Funds flow from (used in) operations	132	413	73	799	293	(109)	493	136
Per share – basic and diluted	0.00	0.00	0.00	0.00	0.00	(0.00)	0.00	0.00
Net income (loss)	(7,513)	(4,115)	(118)	288	(625)	(833)	(215)	(31)
Per share – basic and diluted	(0.05)	(0.03)	(0.00)	0.00	(0.00)	(0.01)	(0.00)	(0.00)
Property expenditures, net of dispositions	678	1,566	191	363	143	2,949	135	459
Working capital deficit	(7,723)	(7,127)	(6,337)	(6,723)	(7,531)	(7,477)	(7,968)	(17,679)
Total assets	31,491	37,284	39,473	39,442	39,370	38,758	36,769	36,146
Weighted Average Shares - basic	163,852	163,852	163,852	163,815	163,802	144,020	128,802	128,802

The Company currently continues to generate positive funds flow from operations, while keeping its working capital deficit relatively unchanged, indicating moderate success despite the current challenging world commodity pricing environment. All other significant items have been discussed elsewhere in this report.

SELECTED ANNUAL INFORMATION

The following table sets forth selected annual financial information of the Company for the three most recently completed years ending March 31:

	Twelve months ended March 31		
	2015	2014	2013
Financial *($000's except per share data)*			
Oil and natural gas revenue	10,136	10,008	8,416
Funds flow from (used in) operations	1,418	815	(1,501)
Per share – basic and diluted	0.01	0.01	(0.01)
Loss	(11,458)	(1,704)	(6,702)
Per share – basic and diluted	(0.07)	(0.01)	(0.06)
General & administrative	1,791	1,873	2,682
Property expenditures, net of dispositions (if any)*	2,798	3,686	5,340
Working capital deficit	(7,723)	(7,531)	(17,574)
Shareholders' equity	3,259	14,423	12,395
Total assets	31,491	39,370	37,254
Operating *(average daily production)*			
Oil and natural gas liquids (bbls/d)	354	291	282
Natural gas (mcf/d)	1,270	1,587	2,390
Equivalent barrels (boe/d)	565	555	681

* relates to expenditures on property and equipment, acquisitions and exploration and evaluation assets

During the year ended March 31, 2013, the natural gas pricing environment continued to be poor, and as such the Company focused its efforts on oil related projects. The Company's financial performance during the year was negatively impacted due to: lower commodity prices for both natural gas and oil; an unusual, acute period of downtime on main producers in Eye Hill resulting in lower production and revenues; and higher operating costs associated with alleviating the downtime. In late January 2013, the Company successfully alleviated the down-time issues with its Primate producers, restoring production rates and operating costs to a normalized level.

During the year-ended March 31, 2014, the Company continued its focus on oil production given its superior netbacks and as a result significantly improved its financial position and performance. Improved oil production volumes, increased netbacks for both oil and gas production, and reduced G&A all combined to materially improve the Company`s overall funds flows.

During the year-ended March 31, 2015, the Company continued to focus on its oil operations given the superior netbacks, and maintained its production levels and improved corporate funds flow from operations despite relatively low capital spending. The Company's capital spending focused on reducing operating costs and improving production on currently existing wells. Unfortunately, the large decrease in world oil pricing significantly affected funds flow from operations during the third and fourth quarter of the year.

Currently, the main risks and trends that may affect the Company are those associated with the pricing of its oil and natural gas production, and the uncertainty with maintaining production volumes commonly experienced with conventional heavy oil producers.

LIQUIDITY AND CAPITAL RESOURCES

In July 2014, the Company replaced its bank debt lender with another Canadian chartered bank. In conjunction with this replacement, the previous bank debt lender was repaid in full and those lending facilities cancelled.

As at March 31, 2015, the Company had lending facilities with a Canadian chartered bank, consisting of a $17 million revolving demand operating credit facility of which $6.4 million was drawn ($0.1 million on the prime-based facility and $6.3 million drawn under guaranteed notes). The revolving facility is a borrowing base facility that is determined based on, among other things, the Company's current reserve report, the results of operations, current and forecasted commodity prices and the current economic environment. The revolving credit facility contains standard commercial covenants for facilities of this nature. The Company also has available a risk management facility which allows the Company to conduct certain financial risk management options. The interest rate on the facility is bank prime plus 1.75% per annum. Guaranteed notes are subject to a 2.75% acceptance fee plus an applicable market interest rate. The facilities are secured by a general security agreement covering all assets of the Company including a subordination agreement with the lender of the 'loans payable', and repayments are interest only, subject to the bank's right of demand. The revolving credit facility provides that advances may be made by way of direct advances, guaranteed notes, or standby letters of credit/guarantee.

The revolving facility has the following financial covenant requirements:

- The working capital ratio must be maintained above 1.0 to 1. The working capital ratio is defined as current assets (excluding derivative assets if any) plus the undrawn availability of the revolving facility to current liabilities (excluding the current portion of bank debt and derivative liabilities if any).
- The senior debt to cash flow ratio must not exceed 3.0 to 1. The senior debt to cash flow ratio is defined as the amount drawn under the bank facility to net income for the trailing one year period from the balance sheet date adjusted for non-cash items and interest accrued on subordinated debt, and less dividends declared and repayments of shareholder loans.

At March 31, 2015 both the above financial covenants were met.

In addition, the Company may not enter into any risk management agreements with a term greater than two years or for a volume greater than 60% of its forecasted production from proved producing reserves.

The facilities may be reviewed at any time; however the next review date is scheduled for July 31, 2015.

The Company's credit facility is a demand loan and as such the bank could demand repayment at any time. However, management is not aware of any indications that the bank would demand repayment in the next 12 months. Indicators considered include the Company has not had any breach or default of bank covenants during the three month periods ended December 31, 2014 and March 31, 2015, and on-going discussion with its bank. During the three month period ended September 31, 2014, the "senior debt to cash flow" ratio was not met. However subsequent to September 30, 2014 the Company's bank provided a waiver of the ratio and also increased the same ratio to 3.5 to 1.0 from 3.0 to 1.0 for the three month period ended December 31, 2014 only. The Company further ensures that it will have sufficient cash on hand to meet immediate obligations by actively monitoring its credit facilities through coordinating payment cycles with revenue cycles on the 25th of each month and an active hedging program to mitigate commodity price risk and secure cash flows.

As noted above, the Company has a revolving demand operating credit facility with a $17.0 million limit, and as of March 31, 2015, there was $10.6 million available for use. However, given the amount available for use under the facility is also limited by the "senior debt to cash flow" ratio, the actual limit will vary on a period by period basis. The calculations of the applicable ratios as of March 31, 2015 are presented below. Management actively forecasts applicable cash flows and will conduct an appropriate capital program based on estimated future credit facility availability. Management believes with its current credit facility and positive expected operating cash flows in the near future given the recent increase in world oil prices that the Company will generate sufficient cash flows to meet its foreseeable obligations in the normal course of operations. Management has significantly delayed the Company's capital programs until the pricing environment improves and has and continues to work on strategies to reduce general and administrative and operating costs subsequent to March 31, 2015. Management has been and continues to be active in seeking alternative sources of funding to help accelerate its planned capital expenditure program, and to ultimately reduce its total debt. The Company cannot provide any assurance that sufficient cash flows will be generated from operating activities to reduce its working capital deficiency and to carry out its planned capital expenditure program.

Subsequent to March 31, 2015 the Company entered into various financial swap transactions which will provide security for future funds flows and low-cost credit availability.

The Company's capital management policy is to maintain a strong capital base that optimizes the Company's ability to grow, maintain investor and creditor confidence and to provide a platform to create value for its shareholders. The Company maintains a flexible capital structure to maximize its ability to pursue oil and natural gas acquisition, exploration and development opportunities and the requirement to sustain future development of the business. The Company monitors the level of risk associated for each capital project to balance the proportion of debt and equity in its capital structure. The Company monitors capital based on its current working capital, available bank line of credit, projected cash flow from operating activities and anticipated capital expenditures. The Company's officers are responsible for managing the Company's capital and do so through quarterly meetings and regular reviews of financial information, including budgets and forecasts. The Company's directors are responsible for overseeing this process. The Company considers its capital structure to include shareholders' equity, bank debt and loans payable.

There have been no changes to the Company's management of capital during the year ended March 31, 2015, except for management is now monitoring its "senior debt" to cash flow" ratio which is a new bank financial covenant of the credit facility the Company obtained in July 2014. Senior debt to cash flow provides a measure of the Company's ability to manage its debt levels under current operating conditions.

The Company monitors capital based on three financial ratios: net debt to amount of available credit facility, working capital ratio, and senior debt to cash flow ratio.

Net debt to amount of available credit facility

	March 31, 2015	March 31, 2014
Net debt [(1)]		
Current assets	914,588	1,527,575
Current liabilities	(8,637,799)	(8,391,482)
Total net debt	(7,723,211)	(6,863,907)
Revolving credit facility available	17,000,000	8,000,000
% of credit facility utilized	45%	86%

(1) Net debt is defined as current assets minus current liabilities excluding derivative instruments.

Overall the ratio of credit facility utilized decreased from the March 31, 2014 due to the increased limit of the credit facility.

Working capital ratio

Under the Company's revolving credit facility, the Company is required to maintain a working capital ratio of greater than 1.0 to 1.0. The working capital ratio is defined as "the ratio of current assets (including undrawn available credit under the revolving demand facility and excluding derivative instruments) divided by current liabilities (less the current portion of bank debt and derivative instruments)". At March 31, 2015, the working capital ratio was 5.2 to 1.0 (March 31, 2014 – 1.6 to 1.0). Overall the ratio has increased due to the increased limit of the credit facility.

Senior debt to cash flow ratio

Under the Company's credit facility obtained in July 2014, the Company is required to maintain a senior debt to cash flow ratio of less than 3.0 to 1.0. The senior debt to cash flow ratio is defined as the amount drawn under the bank facility to net income for the trailing one year period from the balance sheet date adjusted for non-cash items and interest accrued on subordinated debt, and less dividends declared and repayments of shareholder loans. The ratio as of March 31, 2015 was 2.9 to 1.0. During the three month period ended September 31, 2014, the "senior debt to cash flow" ratio was not met. However subsequent to September 30, 2014 the Company's bank provided a waiver of the ratio and also increased the same ratio to 3.5 to 1.0 from 3.0 to 1.0 for the three month period ended December 31, 2014 only.

CAPITAL EXPENDITURES

The following table summarizes property and equipment expenditures (expenditures on both exploration and evaluation and developed properties are included) for the years ended March 31, 2015 and 2014:

$000s	Year ended March 31, 2015	Year ended March 31, 2014
Land acquisitions	-	6
Geological and geophysical	73	55
Drilling and completions	845	2,061
Equipping and facilities	1,872	1,538
Other	8	26
Total net property expenditures	2,798	3,686

Capital Expenditure Highlights

During the year ended March 31, 2015, cash capital expenditures consisted of the following significant items:

- Optimization of the downhole equipment/set-up on 3 gross (3.0 net) wells in Eye Hill
- Deepening of 1 gross (1.0 net) well in Eye Hill for water disposal purposes
- Installation of water and natural gas handling infrastructure in Eye Hill
- Optimization of the downhole equipment in 2 gross (1.9 net) wells in Grand Forks

During the three month period ended March 31, 2015, cash capital expenditures consisted of the following significant items:

- Completion of a water injection facility in Eye Hill
- Optimization of the downhole equipment in 1 gross (1.0 net) wells in Eye Hill

SHARE CAPITAL

During the year ended March 31, 2015, the Company granted 2,550,000 stock options to certain employees, consultants, and directors at a weighted average exercise price of $0.07 per share, whereby; 2,350,000 vested as to one-quarter immediately and one-quarter in each of the following three years, and expire in five years and; 200,000 vested immediately.

Please refer to notes 12 and 13 of the audited financial statements for the years ended March 31, 2015 and 2014, for more details of equity changes during the years.

As at March 31, 2015 and the date of the MD&A, the Company had 163,852,246 common shares, and 13,325,000 stock options outstanding.

CONTRACTUAL OBLIGATIONS

The Company has the following commitments:

(a) Office lease

The Company has an office lease agreement which expires in August 2015. The lease requires future payments inclusive of estimated operating costs of $56,000 for fiscal 2016.

(b) On April 15, 2015, the Company received an invoice from a third party for approximately $535,000 (a revision to the original invoice received in March 2014 of $456,000) related to production volume discrepancies. The amount has not been recognized in the Company's accounts as the legitimacy of the invoice or any amounts owing cannot be ascertained at this time.

RELATED PARTY TRANSACTIONS

(a) For the year ended March 31, 2015, the Company incurred $179,000 in management and engineering consulting fees from a private company in which a director and officer of the Company is the private company's principal shareholder.

(b) For the year ended March 31, 2015, the Company incurred $33,626 in legal fees from a law firm in which a director of the Company is a principal. The fees have been recorded as follows:

$9,899 as finance expense, with the remaining $23,727 being included in general and administrative expenses.

SUBSEQUENT EVENT

In April 2015, the Company entered into the following fixed price contracts as part of its risk management program:

Term	Notional Amount	Fixed Price/Rate	Settlement Index
Apr. 1, 2015 - Mar. 31, 2016	200 to 240 bbl/d	($14.75) USD/bbl	WCS differential to WTI
Apr. 1, 2016 - Mar. 31, 2017	160 to 190 bbl/d	($15.70) USD/bbl	WCS differential to WTI
May 2015 - April 2017	$240,000 to $280,000 USD/month	$1.25 CDN/USD	Bank of Canada rate

OFF-BALANCE SHEET ARRANGEMENTS

The Company does not have any arrangements that would be excluded from the balance sheet as at March 31, 2015, nor are any such arrangements outstanding as of the date of this MD&A.

CRITICAL ACCOUNTING ESTIMATES

The timely preparation of financial statements requires management to make judgments, estimates and assumptions based on currently available information that affect the application of accounting policies and the reported amounts of assets, liabilities and contingent liabilities at the date of the financial statements and reported amounts of revenues and expense during the reporting period. Estimates and underlying assumptions and judgments are reviewed on an ongoing basis and are based on management's experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances. Accordingly, actual results may differ from these estimates. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected.

<u>Significant judgments in applying accounting policies</u>

In the process of applying the Company's accounting policies, management has made the following significant judgments which have the most significant effect on the amounts recorded in the financial statements:

(i) CGU identification

Oil and natural gas interests, exploration and evaluation assets and other corporate assets of the Company are aggregated into CGUs based on their ability to generate largely independent cash flows and are used for impairment testing. The classification of assets into CGUs requires significant judgment and interpretations with respect to the integration between assets, the existence of active markets, external users, shared infrastructures and the way in which management monitors the Company's operations. The Company has identified Willesden Green, Eyehill and Grand Forks as its core CGUs.

(ii) Valuation of oil and natural gas assets

Judgments are required to assess when impairment indicators, or reversal indicators, exist and impairment testing is required. The Company monitors internal and external indicators of impairment relating to its oil and natural gas interests. These indicators include changes in commodity prices, reserve volumes and discount rates.

(iii) Componentization

For the purposes of depletion, the Company allocates its oil and natural gas interests to components with similar lives and depletion methods. The groupings of assets is subject to management's judgment and is performed on the basis of geographical proximity and similar reserve life. The Company's oil and natural gas assets are depleted on a unit of production basis.

(iv) Exploration and evaluation assets

The application of the Company's accounting policy for exploration and evaluation assets requires management to make certain judgments of an area's technical feasibility and commercial viability based on proved and probable reserves as well as related future cash flows and management's intention for future development.

(v) Deferred tax

The Company follows the liability method for calculating deferred taxes. Judgment is required in applying tax laws and regulations and estimating the realizability of deferred tax assets. Assessing the recoverability of deferred tax assets requires the Company to make estimates related to the expectations of future cash flows from operations.

(vi) Contingencies

Contingencies will only be resolved when one or more future events occur or fail to occur. The assessment of contingencies inherently involves the exercise of significant judgment and estimates of the outcome of future events.

Key sources of estimation uncertainty

The following are the key estimates and related assumptions concerning the sources of estimation uncertainty at the end of the reporting period, that have a significant risk of causing adjustments to the carrying amounts of assets and liabilities:

(i) Reserves

The assessment of reported recoverable quantities of proved and probable reserves include estimates regarding production volumes, commodity prices, exchange rates, remediation costs, timing and amount of future development costs, and production, transportation and marketing costs for future cash flows. The process of estimating reserves is complex. It requires significant estimates and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and natural gas prices and costs change. The reserve estimates are based on current production forecasts, prices and economic conditions. Future development costs are estimated using assumptions as to the number of wells required to produce commercial reserves, the cost of such wells and associated production facilities and other capital costs.

As circumstances change and additional data becomes available, reserve estimates also change. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and governmental incentives/restrictions. Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. As a result, subjective decisions, new geological or production information and changing environment may impact these estimates. Revisions to reserve estimates can arise from changes in forecast oil and natural gas prices and reservoir performance. Such revisions can be either negative or positive.

Changes in reported reserves can impact the carrying value of the Company's oil and natural gas interests, the calculation of depletion and depreciation, the provision for decommissioning provisions, and the recognition of deferred tax assets due to changes in expected future cash flows. The Company's oil and natural gas reserves are independently evaluated by reserve engineers at least annually and are determined pursuant to National Instrument 51-101, Standard of Disclosures for Oil and Gas Activities.

(ii) Valuation of oil and natural gas interests

The recoverable amount of CGUs and individual assets are based on the higher of their value-in-use and fair value less costs of disposal. These calculations require the use of estimates and assumptions. Unless indicated otherwise, the recoverable amount used in assessing impairment losses is fair value less costs of disposal. The Company estimates fair value less costs of disposal using a before tax discounted cash flow model which has a number of assumptions. The model uses expected cash flows from proved plus probable reserves as estimated by the Company's third party reserve evaluators. Reserve estimates and expected future cash flows from production of reserves are subject to estimation uncertainty as discussed above and subject to variability to changes in forecasted commodity prices. The discount rate applied to the cash flows is also subject to management's estimate of fair value less costs of disposal and will affect the recoverable amount calculated. The Company utilized a 10% discount rate for oil interests and a 20% discount rate for natural gas interests in its CGU impairment testing. Commodity price changes impact the expected future cash flows which may require a material adjustment to the carrying value of oil and natural gas interests.

(iii) Decommissioning and restoration costs

The calculation of decommissioning provisions includes estimates of the future costs to settle the liability, the timing of the cash flows to settle the liability, the current risk-free interest rate and future inflation rates. Decommissioning and restoration costs are uncertain and cost estimates can vary in response to many factors including change to relevant legal and regulatory requirements, the emergence of new restoration techniques, or experience at other production sites. The expected timing and amount of expenditure can also change in response to changes in reserves and or changes in laws and regulations or their interpretations. In most instances, removal of assets occurs many years in the future. The decommissioning provisions on the balance sheet represents management's best estimate of the present value of the future decommissioning costs required at that reporting date.

(iv) Income taxes

The amounts recorded for deferred tax expense (recovery) and deferred tax assets/liabilities are based on management's estimates as to the timing of the reversal of temporary differences and tax rates currently substantively enacted and the likelihood of tax assets being recognized. The availability of tax pools and other deductions are subject to audit and interpretation by taxation authorities.

(v) Share-based payments

The Company uses the Black-Scholes pricing model when determining fair value of share-based payments because management has determined this is the most appropriate valuation model. The Black-Scholes pricing model requires the Company to determine the most appropriate inputs including the expected life of the option (based on historical experience and general holder behaviour), volatility, expected forfeitures, risk-free rate (based on government bonds) and market prices surrounding the issuance of stock options. These estimates impact stock-based compensation expense, contributed surplus, and share capital.

(vi) Derivative instruments

The amounts recorded for the fair value of derivative instruments are based on estimates of future commodity prices, foreign exchange rates and the volatility in those prices.

(vii) Joint operations

The Company is party to various joint operating and other agreements in conjunction with its oil and natural gas activities. The revenues and expenses allocated between partners are governed by the terms of these agreements and are subject to interpretation and audit by the appropriate parties.

New accounting policies

- On April 1, 2014, the Company adopted IFRS Interpretations Committee (IFRIC) 21, "Levies" which provides guidance on accounting for levies in accordance with the requirements of IAS 37, "Provisions, Contingent Liabilities and Contingent Assets". The interpretation clarifies that an entity is to recognize a liability for a levy when the activity that triggers the payment occurs. The interpretation also clarifies that a levy liability is to be accrued progressively only if the activity that triggers payment occurs over a period of time, in accordance with the relevant legislation. The adoption of this interpretation had no impact on the Company's financial statements.

- On April 1, 2014, the Company adopted the amended IAS 36, "Impairment of Assets". The amendments reduce the circumstances in which the recoverable amount of cash generating units ("CGUs") is required to be disclosed and clarifies the disclosures required when an impairment loss has been recognized or reversed in the period. The additional disclosures required as a result of adoption of this standard have been included in the Company's disclosures in the notes to the financial statements.

- On April 1, 2014, the Company adopted several narrow-scope amendments to a total of nine standards issued by the IASB in December 2013. The adoption of these amendments had no impact on the financial statements.

The Company will be required to adopt each of these new standards in future years:

Financial Instruments

- IFRS 9, "Financial Instruments" provides a comprehensive new standard for accounting for all aspects of financial instruments. It includes a logical model for classification and measurement, a single, forward-looking 'expected-loss' impairment model and a substantially reformed approach to hedge accounting. The new standard is effective for years beginning on or after January 1, 2018. The Company has not determined the impact of the new standard on its financial statements.

Revenue Recognition

- IFRS 15, "Revenue from Contracts with Customers" provides a comprehensive new standard for recognition, measurement and disclosure of revenue from contracts with customers, excluding contracts within scope of the standards on leases, insurance contracts and financial instruments. It specifies how and when to recognize revenue as well as requiring entities to provide more informative and relevant disclosure. The new standard is effective for years beginning on or after January 1, 2017. The Company has not determined the impact of the new standard on its financial statements.

ASSESSMENT OF BUSINESS RISKS

Although it was incorporated in 1968, the Company began operating under the current business model in 2009. It does not have a history of earnings, nor has it paid any dividends and currently there is no plan to pay any dividends in the future. The Company's ability to continue as a going concern is dependent upon the Company achieving profitable results on an ongoing basis, however, there is no assurance that this will occur and that the Company will be able to continue operations in the future.

The following are the primary risks associated with the business of Edge. These risks are similar to those affecting other companies competing in the conventional oil and natural gas sector. Edge's financial position and results of operations are directly impacted by these factors and include:

- Operational risk associated with the production of oil and natural gas;
- Reserve risk in respect to the quantity and quality of recoverable reserves;
- Exploration and development risk of being able to add new reserves economically;
- Market risk relating to the availability of transportation systems to move the product to market;
- Commodity risk as oil and natural gas prices fluctuate due to market forces;
- Financial risk such as volatility of the Canadian/US dollar exchange rate, interest rates and debt service obligations;
- Human resource risk in respect of maintaining access to expertise;
- Environmental and safety risk associated with well operations and production facilities;
- Changing government regulations relating to royalty legislation, income tax laws, incentive programs, operating practices and environmental protection relating to the oil and natural gas industry; and
- Continued participation of Edge's lenders.

The Company seeks to mitigate these risks by:

- Acquiring properties with established production trends to reduce technical uncertainty as well as undeveloped land with development potential;
- Maintaining a low cost structure to maximize product netbacks and reduce impact of commodity price cycles;
- Diversifying properties to mitigate individual property and well risk;
- Maintaining product mix to balance exposure to commodity prices;
- Conducting rigorous reviews of all property acquisitions;
- Monitoring pricing trends and developing a mix of contractual arrangements for the marketing of products with creditworthy counterparties;
- Adhering to the Company's safety program and adhering to current operating best practices;
- Keeping informed of proposed changes in regulations and laws to properly respond to and plan for the effects that these changes may have on the Company's operations;
- Carrying industry standard insurance;
- Establishing and maintaining adequate resources to fund future abandonment and site restoration costs; and
- Monitoring joint venture partners' obligations and cash calling for capital projects to limit the Company's credit risk.

FORWARD LOOKING INFORMATION

This MD&A may contain forward-looking statements and assumptions in respect to various matters including statements related to the future sale of assets and the future need to raise additional capital, the ability of the Company to continue to sustain future positive funds flow from operations and to continue operations in the future, the view and outlook of future commodity prices, cyclical industry fundamentals, commodity mix, timing of expenditures, budgeted capital expenditures and the method of funding thereof and the nature of the expenditures, expected production rates including 2015 exit rates, decommissioning costs, future potential property and equipment and exploration and evaluation asset impairments under

IFRS. All constitute "forward-looking information" within the meaning of applicable Canadian securities legislation, as well as all statements that involve known and unknown risks, uncertainties and other factors that may cause the actual results, performance or achievements of the Company, or industry results, to be materially different from any future results, performance or achievements expressed or implied by such forward-looking information. When used in this MD&A, such statements use such words as "may", "will", "intend", "should", "expect", "believe", "plan", "anticipate", "estimate", "predict", "potential", "continue" or the negative of these terms or other similar terminology. These statements are also "forward-looking information" within the meaning of applicable Canadian securities legislation, and they reflect current expectations regarding future events and operating performance and speak only as of the date of this MD&A.

Forward-looking information involves significant risks and uncertainties, should not be read as guarantees of future performance or results, and will not necessarily be accurate indications of whether such results will be achieved. A number of factors could cause actual results to differ materially from the results discussed in the forward-looking information.

Although the forward-looking information contained in this MD&A is based upon what management believes are reasonable assumptions, the Company cannot assure investors that actual results will be consistent with these forward-looking statements. This forward-looking information is provided as of the date of this MD&A. The Company does not assume any obligation to update or revise them to reflect new events or circumstances, except as required by applicable securities legislation.

ABBREVIATIONS USED IN THIS MD&A

- bbl - barrels
- mbbl - thousand barrels
- mmbbl - million barrels
- bbl/d - barrels per day
- API - American Petroleum Institute
- mcf - thousand cubic feet
- mmcf - million cubic feet
- mcf/d - thousand cubic feet per day
- mmcf/d - million cubic feet per day
- GJ - gigajoule
- bcf - billion cubic feet
- tcf - trillion cubic feet
- boe - barrel of oil equivalent converting six mcf of natural gas to one barrel of oil (6:1)
- boe/d - barrels of oil equivalent per day
- bopd - barrels of oil per day
- mboe - thousands of barrels of oil equivalent
- NCGORR - non-convertible gross overriding royalty
- NPV - net present value
- NGL – natural gas liquids