

MANAGEMENT'S DISCUSSION AND ANALYSIS

March 21, 2007

The following is Management's Discussion and Analysis ("MD&A") of Iteration Energy Ltd.'s (the "Company" or "Iteration") operating and financial results as at and for the year ended December 31, 2006 as well as information and estimates concerning the Company's future outlook based on currently available information. This discussion should be read in conjunction with Iteration's audited consolidated financial statements as at and for the year ended December 31, 2006, together with accompanying notes. Readers should also refer to Iteration's Annual Information Form for the year ended December 31, 2006 ("AIF"). All financial information is reported in Canadian dollars, unless noted otherwise, and in accordance with Canadian generally accepted accounting principles ("GAAP").

Certain amounts in prior periods have been reclassified to enable comparison with the current period's presentation.

Natural gas is converted to crude oil equivalent at a ratio of six thousand cubic feet to one barrel. Boe's may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf: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.

Additional information about Iteration Energy Ltd. filed with Canadian securities commissions, including periodic quarterly and annual reports and the AIF, is available on-line at www.iterationenergy.com and at www.sedar.com.

ITERATION OVERVIEW

Iteration is a Canadian oil and gas company with focus areas in Northeast British Columbia/Northwest Alberta, East Central Alberta and Southwest Saskatchewan. The most significant currently producing properties are Boundary Lake and Rigel in Northeast British Columbia and Atmore and Wild River in Alberta.

The Company strives to operate its properties whenever possible and to maintain high working interests. Iteration believes this high level of operatorship can translate to controlling costs, timing of capital outlays and projects as well as providing competitive advantages for future opportunities.

Issuance of 2,300,000 common shares on a flow through basis

Pursuant to a private placement agreement dated December 6, 2006, the Company issued 2,300,000 common shares on a flow-through basis for gross proceeds of \$12,075,000 to finance certain oil and gas expenditures to be incurred in 2007. The renunciation of these expenditures was made to the purchasers of these shares in 2007 and accordingly, share capital will be reduced by the amount of the tax benefits to be realized associated with these expenditures (\$3,743,000) at that time. Under the look back provision governing flow-through shares, the Company is required to incur these eligible expenditures prior to December 31, 2007.

Acquisition of East Central Alberta Assets

Pursuant to a purchase and sale agreement dated June 6, 2006, on June 27, 2006 the Company purchased, with an effective date of April 1, 2006, certain petroleum and natural gas properties and related assets in east central Alberta from an unrelated oil and gas company. The gross purchase price was \$42,325,000, subject to adjustments. The adjusted purchase price was \$41,426,000. The Company assumed an asset retirement obligation of \$2,510,000 associated with this acquisition. The acquisition was initially funded by bank debt. The Company commenced reporting production from this acquisition July 1, 2006.

Issuance of 6,200,000 Subscription Receipts

Pursuant to a short form prospectus dated June 22, 2006, the Company issued 6,200,000 subscription receipts for gross proceeds of \$25,110,000 on June 28, 2006. The subscription receipts were converted into common shares after the closing of the acquisition of the east central Alberta Assets on June 27, 2006. The

net proceeds of the offering were applied to reduce bank debt of the Company incurred in connection with the acquisition of the east central Alberta Assets.

Acquisition of North East British Columbia Assets

Pursuant to two purchase and sale agreements dated December 22, 2005 and March 10, 2006, the Company purchased certain petroleum and natural gas properties and related assets in northeast British Columbia from unrelated oil and gas companies. The combined gross purchase price was \$8,805,000, subject to adjustments. The transactions closed January 24, 2006 and March 17, 2006 respectively. As a result of the acquisitions, the Company acquired approximately 170 boed of production and a significant undeveloped land base. The acquisition was funded out of available cash.

Acquisition of Iteration Energy Inc.

On March 21, 2005, the Company purchased all of the issued and outstanding shares of Iteration Energy Inc. in exchange for the issuance of 5,750,000 common shares of Iteration and 5,000,000 warrants. The 5,750,000 shares of Iteration are subject to an escrow agreement and are being released as to a third of the issued shares on each of March 20, 2006, 2007 and 2008, respectively. The performance warrants have a term of 42 months and an exercise price of \$2.90 per share. The warrants vested on May 7, 2005. In conjunction with this acquisition, the Company granted 4,610,000 stock options with an exercise price of \$2.90 to the employees of Iteration Energy Inc. who joined Iteration. The stock options vest over a three-year period and expire after five years.

Divestiture of Lavoy Area Assets

Pursuant to two asset sale agreements dated March 21, 2005, the Company sold its Lavoy area assets to two unrelated third parties for cash consideration totaling \$85.0 million, with an effective date of January 1, 2005. The net proceeds received from the asset sale were \$80.8 million after adjustments for operating results and capital expenditures between the effective date and the closing date of March 24, 2005.

FINANCIAL AND OPERATIONAL HIGHLIGHTS

The major highlights of the three months ended December 31, 2006 include:

- Drilled 6.1 net gas wells and 2.0 net heavy oil wells with a success rate of 100%.
- Increased quarter over quarter production by 10% to approximately 5,210 boed, and quarter over quarter exit rate by 18 % to 6,050 boed.
- The production of 725 boed on the east central Alberta June acquisition was increased to 1,200 boed in the 3rd quarter and raised to 1,900 boed by year end.
- Increased the Company's land base to approximately 314,000 net acres, 193,200 of which are undeveloped.
- Commenced exploration on lands acquired through a farm-in deal in northeast British Columbia whereby the Company will earn a 70% interest in 9,500 acres of land.
- Average netback realized during the quarter was \$20.69 per boe, which resulted in funds flow for the quarter of \$8.2 million (\$0.15 per share).

Major highlights for the year ended December 31, 2006 include:

- An 80% increase in Proved plus Probable reserves to 10.9 mmboe.
- A 51% increase in Total Proved reserves to 7.0 mmboe.
- A 60% increase in exit production to 6,050 boed.

- A 49% increase in annual average production to 4,420 boed.⁽¹⁾
- Capital spending of \$114 million resulted in annual replacing production of 1.6 mmboe by a factor of 4 times on a Proved plus Probable basis.
- Drilled 24.8 net gas wells and 7.0 net oil wells with a success rate of 90%.
- Successfully completed two equity issues, one for gross proceeds of \$25.1 million, and the second, a flow through issue for gross proceeds of \$12.1 million.

The following table provides comparative data for year-end 2005 and 2006.

	Dec 31, 2006	Dec 31, 2005	% Change	% Change per share
Total Proved Reserves (mboe)	6,982	4,622	51	28
Proved plus Probable Reserves (mboe)	10,894	6,067	80	53
NAV PV ₁₀ Proved plus Probable Reserves (\$million) ⁽²⁾	208	149	40	19
Annual Average Production (boed) ⁽¹⁾	4,420	2,970	49	34
Exit Production (boed)	6,050	3,770	60	37
Capital Expenditures (\$million)	114	43	164	n/a
Proved plus Probable Finding and Development costs without change in future Capital (\$/boe)	15.00	28.53	(47)	n/a
Proved plus Probable Finding and Development costs with change in future Capital (\$/boe)	18.39	30.34	(39)	n/a
Proved plus Probable Finding, Development and Acquisition costs with change in future Capital (\$/boe)	19.92	30.34	(34)	n/a
Shares outstanding (Million)	57.4	48.9	17	n/a
Land base (thousand net acres)	314	142	121	n/a

(1) The 2005 annual production is reported net of production from the Lavoy assets sold in the first quarter of 2005.

(2) The Company has seen a significant increase in Net Asset Values despite the Dec 31, 2006 value being based on the McDaniel Associates Consultants Ltd. January 1, 2007 price forecasts which are substantially lower than their forecasts a year earlier.

Financial Highlights

The Lavoy property was disposed of on March 24, 2005. Accordingly, the financial results for the period from January 1 to March 24, 2005 include the results of Lavoy. In order to facilitate an understanding of the Company's operating results on a go forward basis, the Lavoy results have been split out in the following table and the Company's analysis of results in this MD&A has focused on changes that were not as a result of the Lavoy disposition.

	Three months ended Dec 31,		Year Ended December 31,			
	2006	2005	2006	2005	2005	2005
	Total	Total	Total	Excluding Lavoy	Lavoy	Total
Financial						
(\$thousands, except as noted)						
Production revenue before royalties	\$17,940	\$20,444	\$64,539	\$57,103	\$8,668	\$65,771
Funds from operations ⁽²⁾	8,290	13,681	32,927	32,679	6,289	38,968
Per Share (\$) ⁽¹⁾						
- basic	0.15	0.28	0.63	0.70	0.13	0.83
- diluted	0.15	0.27	0.63	0.68	0.13	0.81
Net earnings (loss)	(3,225)	4,273	(4,416)	3,072	748	3,820
Per Share (\$) ⁽¹⁾						
- basic	(0.06)	0.09	(0.08)	0.06	0.02	0.08
- diluted	(0.06)	0.08	(0.08)	0.06	0.02	0.08
Royalties	3,298	3,344	13,405	12,457	1,368	13,825
Production expense	4,420	2,925	12,539	6,803	791	7,594
Transportation expense	415	697	1,299	1,108	-	1,108
General and admin	1,251	467	4,084	3,993	-	3,993
Depletion	11,644	6,491	40,115	24,444	5,542	29,986
Total assets	233,824	181,646	233,824	n/a	n/a	181,646
Capital expenditures:						
Property acquisition, net of dispositions	429	(726)	50,836	n/a	n/a	(80,813)
Exploration, development and other	15,358	26,275	63,235	n/a	n/a	44,896
Shares outstanding						
(thousands)						
Common shares Dec 31	57,429	48,895	57,429	n/a	n/a	48,895
Weighted average – basic	55,905	48,873	52,752	n/a	n/a	47,590
Weighted average – diluted ⁽¹⁾	55,905	51,083	52,752	n/a	n/a	49,091
Warrants Dec 31	5,000	5,000	5,000	n/a	n/a	5,000
Stock options Dec 31 ⁽³⁾	5,884	4,798	5,884	n/a	n/a	4,798

- (1) For periods with positive net earnings, per share amounts are based on weighted average basic and diluted common shares outstanding for the period. For periods with a net loss, per share amounts are based on basic common shares outstanding for the period.
- (2) Management uses funds from operations and funds from operations per share (before changes in non-cash working capital and asset retirement expenditures) to analyze operating performance and leverage. Funds from operations and funds from operations per share as presented do not have any standardized meaning prescribed by Canadian GAAP and therefore they may not be comparable with the calculation of similar measures for other entities. Funds from operations as presented is not intended to represent operating cash flow or income from operations for the period nor should it be viewed as an alternative to cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with Canadian GAAP. All references to funds from operations and funds from operations per share throughout this Management's Discussion and Analysis are based on cash flow from operating activities before changes in non-cash working capital.
- (3) In order for the Company to retain and attract qualified staff during 2006, the Compensation Committee of the Board of Directors approved the issuance of conditional options (the "Conditional Options") for employees who are not officers or directors. These Conditional Options were required as there were not a sufficient number of remaining options available, given the cap on options of 10% of outstanding common shares, to be issued to current or prospective employees under the Company's stock option plan. Included in the stock options disclosed above, are 589,000 of these Conditional Options that were granted during the year at a weighted average exercise price of \$4.28 per share. The Conditional Options have a three year vesting period and a term of four years. They are conditional upon ratification by the shareholders at the shareholder meeting on May 14, 2007, pursuant to the requirements of the Toronto Stock Exchange because the granting resulted in the number of common shares available to be issued under the stock option plan exceeding the maximum number allowed under the plan (currently 10% of issued and outstanding common shares). In the event that the shareholders do not ratify the grant of such Conditional Options, all of the Conditional Options granted will immediately and automatically terminate without payment.

Concurrent with the granting of the Conditional Options, the Board adopted a stock appreciation rights ("SAR") plan and granted 589,000 SARs to the employees who were granted the foregoing Conditional Options, with the same exercise price, vesting conditions and term. Upon the exercise of each SAR, the employee will be entitled to receive a cash payment equal to the difference between the closing price of the common shares on the date immediately preceding the date of exercise, and the exercise price of each SAR issued. In the event that the shareholders ratify the grant of the Conditional Options at the shareholder meeting on May 14, 2007, all SARs granted will immediately and automatically terminate without payment and the conditions attaching to the Conditional Options will be satisfied.

Subsequent to year end:

- 207,500 Conditional Options/SARs with an average exercise price of \$4.76 were issued to new employees;
- 4,333 options with an average exercise price of \$4.87 and 12,000 Conditional Options/SARs with an exercise price of \$4.35 were forfeited by employees who left the Company.
- 344,200 options with an exercise price of \$2.90 were exercised for common shares of the Company. This brought the total number of options and Conditional Options to under 10% of the total number of shares outstanding.

Operating Highlights

	Three months ended Dec 31,		Year ended Dec 31			
	2006	2005	2006	2005	2005	2005
	Total	Total	Total	Excluding Lavoy	Lavoy	Total
Operating						
Gas Production						
Total natural gas (bcf)	2.7	1.6	8.9	5.9	1.3	7.2
Daily average natural gas (mcf/d)	29,216	17,725	24,498	16,332	3,528	19,807
Average price (\$/mcf)	6.03	11.57	6.42	8.70	6.70	8.37
Oil and Liquids Production						
Total oil and liquids (Mbbls)	31.5	20.7	122.3	90.7	0.8	91.5
Daily average oil and liquids (bbls/d)	343	225	335	248	3	251
Average price oil and liquids (\$/bbl)	54.93	76.12	58.12	57.57	23.47	57.27
Daily Average Production (boed)	5,212	3,179	4,418	2,970	591	3,561
Land						
Net undeveloped land holdings (acres)	193,200	85,800	193,200			85,800

	Three months ended Dec 31,		Year ended Dec 31			
	2006	2005	2006	2005	2005	2005
	Total	Total	Total	Excluding Lavoy	Lavoy	Total
Drilling						
Wells drilled (net)						
Gas	6.1	8.6	24.8	18.6	-	18.6
Oil	2.0	-	7.0	-	-	-
Dry	-	1.0	3.6	1.0	-	1.0
Total	8.1	9.6	35.4	19.6	-	19.6
Success rate (%)	100.0	90.0	90.0	95.0	-	95.0

Annual Financial Data

<i>(\$ thousands except per share data)</i>	2006	2005	2004
Including Lavoy			
Revenues	64,539	65,771	78,785
Net earnings (loss)	(4,416)	3,820	(1,488)
Total assets	233,824	181,646	202,267

Bank indebtedness	28,640	-	-
Long-term financial liabilities	-	-	51,218
Net earnings (loss) per common share – basic (if net loss) fully diluted (if net earnings) during period	(0.08)	0.08	(0.03)
<u>Excluding Lavoy</u>			
Revenues	64,539	57,539	46,179
Net earnings (loss)	(4,416)	3,072	(4,219)
Net earnings (loss) per common share – basic (if net loss) fully diluted (if net earnings) during period	(0.08)	0.06	(0.10)

Quarterly Financial Data

(\$ thousands except per share data)

Quarter ended	2006				2005			
	Dec 31	Sept 30	June 30	Mar 31	Dec 31	Sept 30	June 30	Mar 31
<u>Including Lavoy</u>								
Revenues	\$17,940	\$16,888	\$12,394	\$17,317	\$20,719	\$13,956	\$10,939	\$20,157
Net earnings (loss)	(3,225)	(2,370)	(1,472)	2,649	4,271	1,519	473	(2,443)
Net earnings (loss) per common share – basic and diluted (\$)	(0.06)	(0.04)	(0.03)	0.05	0.09	0.04	0.01	(0.06)
<u>Excluding Lavoy</u>								
Revenues	\$17,940	\$16,888	\$12,394	\$17,317	\$20,719	\$13,956	\$10,939	\$11,777
Net earnings (loss)	(3,225)	(2,370)	(1,472)	2,649	4,271	1,519	473	(3,222)
Net earnings (loss) per common share – basic and diluted (\$)	(0.06)	(0.04)	(0.03)	0.05	0.09	0.04	0.01	(0.06)

OPERATING RESULTS (EXCLUDING LAVOY)

Net Earnings (Loss)

Iteration's net loss for the three months ended December 31, 2006 was \$3.2 million, as compared to net earnings of \$4.2 million for the three months ended December 31, 2005. Although production was 64% higher during the quarter, as compared to the corresponding period in the prior year, the financial results were impacted by lower realized natural gas prices and higher operating costs associated with increasing production on the recent east central Alberta acquisition.

On a year over year basis, Iteration's net loss for the year ended December 31, 2006 was \$4.4 million versus net income of \$3.0 million for the year ended December 31, 2005. Although production increased 49% on a year over year basis, the increase was offset by a 25% reduction in realized commodity prices. Furthermore, operating costs increased 25% on a boe basis, reflecting the impact of inflationary increases in costs as well as the impact of higher operating costs associated with the east central Alberta acquisition. The Company has not seen any relief with respect to the inflationary pressures on operating costs.

Production

Average daily production for the three months ended December 31, 2006 increased by 2,030 boed as compared to the three months ended December 31, 2005. This 64% increase included production from the east central Alberta acquisition that closed June 27, 2006 and the two northeast British Columbia acquisitions that closed earlier in the year. The production increase was further enhanced by the successful drilling and re-completion of a number of wells in Atmore, Rigel and Bernadet.

On a year over year basis, production increased 49%. This increase was attributable not only to the acquisitions noted above, but also to the results of the Company's drilling program undertaken during the year.

Daily Production (excluding Lavoy) <i>Average for the period</i>	Three months ended Dec 31,			Year ended Dec 31,		
	2006	2005	% Change	2006	2005	% Change
Natural Gas (Mcf/d)	29,716	17,725	68	24,498	16,332	50
Crude oil and natural gas liquids (bbl's/d)	343	225	53	335	248	35
Total (boed)	5,212	3,179	64	4,418	2,970	49

The first quarter 2007 capital program of \$38 million was expected to result in average production of approximately 6,100 boed with an exit rate of approximately 6,900 boed. The current production is approximately 5,800 boed with over 1,600 boed completed behind pipe and waiting on tie-in. A number of recent construction delays mean that much of this gas will not be tied in until the end of March, and some not until after break up. These delays will bring our expected average production for the quarter to approximately 5,900 boed, but we still expect to reach our exit rate of approximately 6,900 boed before break-up.

Commodity Prices

Industry Benchmarks <i>Average for the period</i>	Three months ended Dec 31,			Year ended Dec 31,		
	2006	2005	% Change	2006	2005	% Change
Natural gas (Alberta Spot – monthly) Cdn\$/GJ at AECO	6.03	11.08	(45)	6.62	8.04	(17)
Natural gas (Alberta Spot- daily) Cdn \$/GJ at AECO	6.54	11.37	(42)	6.18	8.73	(29)
Natural gas (BC Westcoast Station 2) Cdn \$/GJ	6.26	11.31	(56)	6.58	8.22	(20)
Edmonton Pentane Cdn\$/bbl	67.86	70.71	(4)	75.03	69.13	9
Edmonton Light Crude Cdn\$/bbl	65.12	71.65	(9)	73.30	69.29	6
Hardisty Lloydblend Cdn\$/bbl	37.67	42.02	(10)	43.32	42.79	2

Realized Commodity Prices <i>Average for the period</i>	Three months ended Dec 31,			Year ended Dec 31,		
	2006	2005	% Change	2006	2005	% Change
Natural Gas (\$/Mcf)	6.03	11.57	(47)	6.42	8.70	(26)
Crude oil and natural gas liquids (\$/bbl's)	54.84	76.13	(28)	58.03	57.57	1
Total (\$/boed)	37.41	69.90	(46)	40.03	53.25	(24)

For purposes of comparing realized prices to benchmark prices, the Company's British Columbia natural gas production is sold at Station 2 pricing (BC Westcoast Station 2) and the majority of the Company's Alberta natural gas production is sold at AECO Spot - daily. Therefore for comparative purposes, the

realized price for the commodity should be compared to the benchmark prices for BC Westcoast Station 2 and Alberta Spot – daily at AECO.

For the 2006 year, the change in the realized price for natural gas was consistent with the change in the benchmark for the year. For crude oil and natural gas liquids, the realized price for the year changed by less than the comparable benchmark due to an over accrual of oil and natural gas liquids from non operated properties in December 2005.

Revenue

Production revenue was \$17.9 million for the three months ended December 31, 2006, compared with \$20.4 million for the three months ended December 31, 2005. The production revenue decrease was due to lower commodity prices realized by the Company during the fourth quarter 2006, which was offset by higher production volumes. For the year ended December 31, 2006, the increase in production revenue was a result of the 49% increase in production for the year, as compared to 2005, offset by a 24% decrease in realized commodity prices.

Production Revenue before Royalties (\$ thousands)	Three months ended Dec 31,			Year ended Dec 31,		
	2006	2005	% Change	2006	2005	% Change
Production revenue	17,939	20,444	(12)	64,539	57,103	13

For each of the three months ended December 31, 2006 and 2005, natural gas production accounted for 93% of the Company's total production. For the year ended December 31, 2006, natural gas production accounted for 92.5% of total production, as compared to 91.5% of production for the year ended December 31, 2005.

Subsequent to the year ended December 31, 2006 the Company entered into the following physical commodity hedges:

Period	Volume	Type	Pricing	Price
Apr 1 – Oct 31, 2007	5,5270 mcf/day	Collar	AECO – monthly	\$7.91 floor, \$8.54 ceiling
Apr 1 – Oct 31, 2007	7,900 mcf/day	Fixed price	BC Westcoast Station 2	\$7.44

Royalties

Royalty expense, net of the Alberta Royalty Tax Credit, was \$3.2 million for the three months ended December 31, 2006, compared with \$3.2 million for the three months ended December 31, 2005. The relatively little change in royalty expense for the fourth quarter in 2006 is the result of increased production offset by lower commodity prices for natural gas.

For the fourth quarter in 2006, the decrease in royalty rate per boe is a result of the decrease in commodity price for the comparative period in 2005.

On an annual basis for 2006, the decline in the royalty rate as a percentage of income is the result of;

- 1) The gas wells that were acquired during the year had a lower royalty rate than the rate on the Company's gas well portfolio at that time.
- 2) The royalty rates on the heavy oil wells brought on production during the year are 13%.

- 3) One of the oil wells drilled in Boundary Lake was granted exploratory status and, therefore, is exempt from crown royalties for a period of 2 years.

Royalties <i>(\$ thousands except where noted)</i>	Three months ended Dec 31,			Year ended Dec 31		
	2006	2005	% Change	2006	2005	% Change
Royalties	3,173	3,219	(1)	12,969	12,457	4
Per boe (\$/boe)	6.62	11.01	(40)	8.04	11.49	(30)
Percentage of revenue (%)	17.69	15.74	12	20.09	21.81	(7)

For first quarter 2007, the Company expects the crown royalty burden to be approximately 21 percent of revenue. The increase in royalty rate is as a result of the termination of the Alberta Royalty Tax Credit program effective December 31, 2006.

Production Expenses

Production expenses were \$4.4 million for the three months ended December 31, 2006, compared with \$2.9 million for the three months ended December 31, 2005. The increase in expenses was due to the following:

- 1) A 64 % increase in production for the quarter as compared to the previous year.
- 2) Operating costs of the assets acquired in June, 2006 was \$9.50 per boe at the time of the acquisition. Considerable extra costs were incurred during the year to continue increasing production from the summer access properties.

Production expenses for the year ended December 31, 2006, on a per boe basis, were 24% higher than production expenses for the preceding year. The reason for the increase was inflationary pressure on operating costs realized during the year, combined with the higher operating costs associated with the acquired assets.

Production expenses <i>(\$ thousands)</i>	Three months ended Dec 31,			Year ended Dec 31,		
	2006	2005	% Change	2006	2005	% Change
Field operating costs	4,300	2,709	60	12,023	6,410	88
Allocated general and administrative costs	120	216	(44)	516	393	32
Total production expense	4,420	2,925	52	12,539	6,803	85

Production expenses per boe <i>(\$ per boe)</i>	Three months ended Dec 31,			Year ended Dec 31,		
	2006	2005	% Change	2006	2005	% Change
Field operating costs	8.98	9.27	(3)	7.46	5.92	26
Allocated general and administrative costs	0.25	0.74	(66)	0.32	0.37	(13)
Total production expense	9.23	10.01	(7)	7.78	6.29	24

The Company had previously published guidance with respect to expected production expenses for the first quarter of 2007 of \$7.02 per boe. With the recent continued upward pressure on costs, and the probability that average production for the quarter will be slightly lower than expected due to delays in the tie in of some wells, it is possible that operating costs per boe for the quarter will be higher than expected.

Operating Netback

The operating netback (before general and administrative expenses) realized for the three months ended December 31, 2006 was \$20.69/boe versus \$46.49/boe for the three months ended December 31, 2005. The decrease in netback realized was primarily due to softening of natural gas prices.

For the year ended December 31, 2006, the operating netback was 32% lower than for the preceding year. The decrease in netback was a result of lower realized production levels from lower commodity prices combined with higher operating costs realized by the Company.

Operating Netback (\$/boe)	Three months ended Dec 31,			Year ended Dec 31,		
	2006	2005	% Change	2006	2005	% Change
Production revenue	37.41	69.90	(46)	40.03	53.25	(24)
Royalties	(6.62)	(11.01)	(39)	(8.04)	(11.49)	(30)
Production costs	(9.23)	(10.01)	(7)	(7.78)	(6.29)	24
Transportation costs	(0.87)	(2.39)	(37)	(0.81)	(1.03)	(21)
Operating netback	20.69	46.49	(45)	23.40	34.44	(32)

For guidance purposes, based on budgeted commodity prices for the first quarter 2007 of \$7.20/GJ AECO for natural gas and WTI of \$60.00/bbl, the Company expects an operating netback (before general and administrative expenses) for the first quarter of 2007 of approximately \$27.65/boe.

General and Administrative Expenses

Expensed general and administrative costs were \$1.2 million for the three months ended December 31, 2006, compared with \$0.5 million for the three months ended December 31, 2005. The reasons for the increase were:

- 1) With the increase in production, the Company engaged several additional personnel in 2006.
- 2) The amounts which were being accrued for a number of general and administrative expenses during the first nine months of 2005 were higher than the actual expenditures, which resulted in a reduction of general and administrative expenses for the quarter ended December 31, 2005, when the accruals were adjusted to actual.
- 3) During the quarter ended December 31, 2006, the Company completed the processes suggested by National Instrument 52-109 as it relates to the documentation and testing of internal financial controls, which resulted in significantly higher professional fees during the quarter.

For the year ended December 31, 2006, general and administrative expenses were almost unchanged from the previous year. However, general and administrative expenses per boe decreased by 17% as compared to the previous year due to an increase in average production realized by the Company in 2006.

Management is continuing its efforts to streamline general and administrative functions within the organization to maintain effective cost control with respect to general and administrative expenses.

General and administrative expenses (\$ thousands except where noted)	Three months ended Dec 31,			Year ended Dec 31,		
	2006	2005	% Change	2006	2005	% Change
General and administrative costs before the following:	1,979	889	123	6,745	6,248	8
Overhead recoveries	(133)	(336)	(60)	(300)	(886)	(66)
Allocation to production expenses	(120)	(216)	(44)	(516)	(393)	32
Capitalized overhead	(475)	130	(366)	(1,865)	(976)	91

General and administrative expense	1,251	467	168	4,084	3,993	3
Per boe (\$ / boe)	2.61	1.60	64	2.54	3.08	(17)

The Company is projecting general and administrative expenses of \$2.23 per BOE for the first quarter of 2007. Although these expenses for the fourth quarter exceeded that amount, fourth quarter expenses were higher due to the costs of completing the documentation of controls over financial reporting as required by National Instrument 52-109. With the increase in production volumes projected for the first quarter of 2007, Management continues to expect that the predicted general and administrative expenses for the first quarter of 2007 will be realized.

Stock Based Compensation Expense

The Company's stock option plan was amended by the shareholders effective April 1, 2004 to provide stock option holders the choice, upon exercise, to receive a cash payment in exchange for surrendering the option. The cash payment is equal to the appreciated value of the stock option, as determined by the difference between the option's exercise price and the Company's closing share price the day prior to electing to exercise the option. In July, 2005, the stock option plan was further amended to limit the total number of common shares that may be issued under the stock option plan to 10% of the issued and outstanding Common Shares at that time.

For the three months ended December 31, 2006, a stock based compensation expense of \$1.9 million was recorded based on the increase in value of the outstanding stock options as determined using the December 31, 2006 closing share price, as compared to the closing share price at September 30, 2006. Future fluctuations in the stock based compensation expense or recoveries are dependent on the movement of the Company's share price and the number of vested options outstanding. Based on the December 31, 2006 share price of \$4.40, had all 5,884,225 stock options outstanding been vested, stock based compensation expense and a corresponding liability of \$7.1 million would have been recognized. Of this amount, \$4.1 million has been recognized as a current liability, and reported as part of accounts payable, in the December 31, 2006 financial statements.

Interest Expense

Interest expense on current debt (the Company had no long term debt) for the three months ended December 31, 2006 was \$0.5 million as compared to interest income of (\$0.1) million for the three months ended December 31, 2005. Interest expense for the three months ended December 31, 2005 represents income earned on the cash balances the Company had at that time. Interest expense for the three months ended December 31, 2006 was as a result of utilizing a portion of the \$50 million credit facility to fund the capital drilling program and the acquisitions during the year. The effective interest rate for 2006 on the outstanding Credit Facility was 6%.

Interest expense (\$ thousands except where noted)	Three months ended Dec 31,			Year ended Dec 31,		
	2006	2005	% Change	2006	2005	% Change
Interest expense	527	(127)	415	1,225	480	156
Per boe (\$/boe)	1.10	(0.44)	250	0.76	0.37	106

Depletion

Depletion and depreciation expense was \$11.6 million for the three months ended December 31, 2006 compared to \$6.5 million for the three months ended December 31, 2005. The increase in the amount of depletion recorded was due to the magnitude of capital spending undertaken by the Company combined

with the higher production for the three months and year ended December 31, as compared to the corresponding periods in 2005.

On a year over year basis, depletion expense increased by 34% to \$40 million in 2006. The reason for the increase is the 49% increase in production as compared to 2005. The depletion rate per boe also increased by 8% from the rate reported in 2005 as a result of the capital expenditure program during the second half of 2005 and in 2006.

Depletion <i>(\$ thousands except where noted)</i>	Three months ended Dec 31,			Year ended Dec 31,		
	2006	2005	% Change	2006	2005	% Change
Depletion	11,644	6,491	80	40,115	29,986	34
Per boe (\$/boe)	24.29	22.20	10	24.88	23.13	8

Capital Expenditures

Exploration and development capital spending for the three months ended December 31, 2006 was \$15.4 million, versus \$26.3 million for the three months ended December 31, 2005. Capital spending during the previous year was higher as the Company had to fulfill the spending requirements of the prior flow through share issuances of the Company.

Capital Expenditures <i>(\$ thousands)</i>	Three months ended Dec 31,			Year ended Dec 31,		
	2006	2005	% Change	2006	2005	% Change
Acquisition of oil and gas properties, net of disposition proceeds	443	-	100	50,836	-	100
Exploration and development expenditures	15,358	26,275	(41)	63,235	44,896	41
Total	15,801	26,275	(39)	114,071	44,896	154

Capital and Liquidity

As an oil and gas company, we have a declining asset base and therefore rely on ongoing development and acquisitions to replace production and add additional reserves. Our future oil and natural gas production and reserves are highly dependent on our success in exploiting our asset base and acquiring additional reserves. To the extent we are successful or unsuccessful in these activities our funds flow could be increased or reduced.

As at December 31, 2006, the Company had a \$50 million Credit Facility with a Canadian chartered bank, which was increased to \$65 million subsequent to year end to accommodate the budgeted 2007 capital expenditure program. The Company expects to spend \$38 million in the first quarter of 2007 as part of an overall capital program that is heavily weighted to the first quarter winter drilling program. There will be very little drilling in the second quarter due to limited surface access and the Company intends to assess the summer gas price before giving guidance or capital spending for the second half of the year.

At the end of the year, the Company had drawn \$28.6 million of the facility. In addition to this debt, the Company had a working capital deficiency of \$3.6 million for a total net debt of \$32.2 million. The ratio of total net debt at December 31, 2006 to 2006 funds flow was 0.98:1.

The Company anticipates no unusual working capital requirements in 2007. There are currently no capital commitments, other than those associated with the Company's 2007 drilling and exploration program, and no known unusual trends or liquidity issues as at March 21, 2007. The Company expects to be able to meet future obligations associated from ongoing operations from funds flow from operations and draws on the Company's Credit Facility.

For guidance purposes the Company has used projected average prices for the first quarter of 2007 of \$7.20 /GJ AECO for gas and \$60.00/bbl. for Edmonton Light oil. The impact on the Company's estimated first quarter funds flow, reported in previous guidance as \$14 million, of a \$1.00/GJ swing in average AECO price for the quarter is approximately \$2.5 million.

Operating Leases

The Company has entered into various operating leases with respect to its premises. The leases expire June 30, 2009 and require the following future minimum lease payments, by calendar year (\$thousands);

2007	687
2008	687
2009	344

Related Party Transactions

For the three months and year ended December 31, 2006, there were no related party transactions.

Outstanding Common Shares

As at March 21, 2007, there were 57,774,047 common shares, 5,000,000 warrants, 4,946,690 options and 774,500 conditional options/ SARs outstanding.

Critical Accounting Estimates

In the application of accounting policies, management is often required to make judgments based on underlying estimates and assumptions about future events and their effects. Underlying estimates and assumptions are based on historical experience and other factors that management believes to be reasonable under the circumstances. These estimates and assumptions are subject to change as new events occur and additional information is obtained. The Company believes the following are the most critical accounting estimates used in determining its financial results.

Full Cost Accounting

The Company follows the full cost method of accounting whereby all costs relating to the acquisition of, exploration for and development of oil and gas reserves are capitalized, whether successful or not. The aggregate of these costs, net of costs of unproved properties and estimated salvage values, and estimated future development costs are depleted and depreciated by the unit of production method based on estimated gross proven reserves as determined by independent engineers. Changes in estimated gross proven reserves, salvage values or future development costs have a direct impact on depletion and depreciation.

Ceiling Test

The Company calculates the ceiling test on reserves based upon estimates of future prices for commodities, production rates, royalty rates, operating costs and inflation rates. Future prices for commodities are based on forward curve amounts. Future production rates, decline rates, royalty rates and operating costs are based on historical amounts. Inflation for commodity prices and operating costs is 2% per annum.

In the calculation of the ceiling test, the carrying value of property and equipment is compared to the sum of undiscounted cash flows expected to result from the future production of proved reserves, salvage value of equipment and the value of seismic over undeveloped land. Cash flows are based on third party quoted forward prices, adjusted for transportation and quality. Should the ceiling test result in an excess of

carrying value, the Company would then measure the amount of impairment by comparing the carrying amounts of property, plant and equipment to an amount equal to the estimated net present value of future cash flows from proved plus probable reserves, salvage value of equipment and value of seismic over undeveloped land. A risk-free interest rate of 6% was used to arrive at the net present value of the future cash flows. Any excess is recorded in the statement of earnings.

The carrying value of undeveloped properties (land and seismic data) is reviewed periodically and written down to net realizable value if impairment is determined.

Reserve Estimates

On an annual basis, the Company engages independent petroleum consultants to evaluate 100% of its oil and gas reserves. The estimation of reserves is a subjective process. The accuracy of reserve estimates is a product of the quality and quantity of data available, interpretation and judgment. Reserve estimates are based on engineering and geological data, projected future rates of production, commodity price forecasts and estimated timing of future expenditures, all of which are subject to interpretation and uncertainties.

Reserve estimates are used in the calculation of depletion and depreciation. A change in estimated reserves would result in a higher or lower depletion and depreciation charge to net earnings. Downward revisions to reserve estimates could also result in an impairment write-down of property, plant and equipment under the ceiling test.

Asset Retirement Obligations

The Company recognizes the fair value of a liability for an asset retirement obligation in the period in which it is incurred and records a corresponding increase in the carrying value of the related long-lived asset. The fair value is determined through a review of engineering studies, industry guidelines, and management's estimates on a site by site basis. The liability is subsequently adjusted for the passage of time, and is recognized as an accretion expense in the statement of earnings under asset retirement obligations. The liability is also adjusted due to revisions in either the timing or the amount of the original estimated cash flows associated with the liability. Estimates of the asset retirement costs are subject to uncertainty associated with the method, timing and extent of future retirement activities.

The Company calculates the asset retirement obligation based on estimates of the date of abandonment, abandonment costs, and inflation. These amounts are then discounted to a present value amount. The estimates used are as follows:

Abandonment and reclamation costs:

Well bore and surface reclamation	\$ 35,000 per well
Pipelines	10,000 per pipeline segment
Roads	15,000 per km
Batteries	15,000 per battery
Compressors	200,000 per compressor
Inflation	2 % per annum
Discount rate	6% per annum

Income Taxes

The Company records future tax assets and liabilities to account for the expected future tax consequences of events that have been recorded in its consolidated financial statements and its tax returns. These amounts are estimates; the actual tax consequences may differ from the estimates due to changing tax rates and regimes, as well as changing estimates of cash flows and capital expenditures in current and future periods. The Company periodically assesses the realizability of its future tax assets. A valuation allowance is recorded to the extent that there is uncertainty regarding utilization of future tax assets.

Impact of New Accounting Pronouncements

Effective January 1, 2007, the Company will be required to adopt the following new CICA accounting standards:

- Section 1530 – Comprehensive Income
- Section 3855 – Financial Instruments – Recognition and Measurement
- Section 3865 – Hedges

Starting in 2007, Section 1530 will require Companies to present a statement of comprehensive income, defined as a change in net assets arising from transactions and other events from non-owner sources. The statement will present net income and each component to be recognized in other comprehensive income.

Section 3855 has defined the relevant models for valuing financial assets and liabilities in 2007, depending on the nature of the instruments and the requirements of recognition.

Section 3865 defines the criteria needed to qualify for hedge accounting in 2007, as well as the timing for recognition of applicable hedge gains and losses.

These new standards are intended to adapt Canadian standards to more closely match United States accounting standards and International accounting standards. At this time, management believes that these new accounting requirements will not have a material impact on the Company's financial statements.

Disclosure Controls and Procedures

The Company has implemented disclosure controls and procedures to ensure that information required to be disclosed by the Company is accumulated and communicated to the Company's management, as appropriate, to allow timely decisions regarding required disclosures. The Company's Chief Executive Officer and Chief Financial Officer, together with management, have concluded, based on their evaluation as of the year-end, that the Company's disclosure controls and procedures are effective to provide reasonable assurance that material information related to the issuer is made known to them by others.

It should be noted that while the Company's Chief Executive Officer and Chief Financial Officer believe that the Company's disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect that the disclosure controls and procedures will necessarily prevent all errors and fraud. A 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.

Internal Controls over Financial Reporting

Under the supervision of, and with the participation of the Company's management, including the Chief Executive Officer and the Chief Financial Officer, internal control over financial reporting has been designed and maintained in order to provide reasonable assurance regarding the reliability of financial reporting, as of the end of the period covered by the filings. During the quarter ended December 31, 2006, there have been no material changes in internal control over financial reporting. In common with many small companies, with limited accounting support staff, segregation of duties is difficult; however management is satisfied that compensating controls are in place including key management authorizations and reviews.

Outlook for 2007

The first quarter capital program of \$38 million was expected to result in average production of approximately 6,100 boed with an exit rate of approximately 6,900 boed. The current production is approximately 5,800 boed with over 1,600 boed completed behind pipe and waiting on tie-in. A number of recent construction delays mean that much of this gas will not be tied in until the end of March and some not until after break-up. These delays will bring our expected average production for the quarter to approximately 5,900 boed, but we still expect to reach our exit rate of approximately 6,900 boed before break-up. Following the first quarter, the Company expects to continue to focus on adding new drilling locations and prospective lands in order to grow production through an ongoing exploitation and exploration program. The Company is aggressively pursuing acquisition and farm-in opportunities in its core areas, and will continue to be active at land sales. The Company expects to spend very little in the second quarter due to restricted surface access, but has an inventory of prospects in place for the second

half of the year to provide future production growth. The Company will evaluate commodity prices in the summer months before deciding when to start the next round of drilling.

Directors, Officers and Auditors

Current Officers and Directors of the Company are as follows;

Officers

Brian Illing	President and CEO
Mark Ariss	VP Exploration East
Sean Johnson	CFO
Jane Mactaggart	VP Exploitation
Carmen McKay-Illing	VP Corporate Affairs
Kevin Stromquist	VP Exploration West

Directors

Pat Breen P. Eng.	President- Foremost Income Fund
Dallas Droppo Q.C.	Partner- Blake, Cassels and Graydon LLP
Jim Grenon	President- TOM Capital Associates
Michael Hibberd	President- MJH Services Inc.
Brian Illing P. Geol	President and CEO- Iteration Energy Ltd.
Robert Waters CA	Senior VP and CFO- Enerplus Resources Fund

Corporate Secretary

Tony Grenon	Managing Director- TOM Capital Associates
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Auditors

Ernst & Young LLP

Advisory – Forward-Looking Information

This MD&A was prepared on March 21, 2007 and is management's assessment of Iteration's historical financial and operating results. The reader should be aware that historical results are not necessarily indicative of future performance. This MD&A contains forward-looking statements relating to future events or future performance. In some cases, forward-looking statements can be identified by terminology such as "may", "will", "should", "expects", "projects", "plans", "anticipates" and similar expressions. These statements represent management's expectations or beliefs concerning, among other things, future operating results and various components thereof affecting the economic performance of Iteration. Undue reliance should not be placed on these forward-looking statements which are based upon management's assumptions and are subject to known and unknown risks and uncertainties, including the business risks discussed below, which may cause actual performance and financial results in future periods to differ materially from any projections of future performance or results expressed or implied by such forward-looking statements. Accordingly, readers are cautioned that events or circumstances could cause results to differ materially from those predicted. The Company undertakes no obligation, except as required by applicable securities legislation, to update publicly or to revise any of the included forward looking statements, whether as a result of new information, future events or otherwise.

The forward looking statements contained herein are expressly qualified by this cautionary statement. Readers are cautioned that the following list of risk factors is not exhaustive.

In particular, this discussion contains forward-looking statements and information pertaining to the following:

- The quantity and recoverability of our reserves;

- The timing and amount of future production;
- Prices for natural gas produced;
- Operating and other costs;
- Business strategies and plans of Management;
- Supply and demand of natural gas;
- Expectations regarding our ability to raise capital and to add to our reserves through acquisitions as well as exploration and development;
- The focus of capital expenditures on development activity rather than exploration;
- The sale, farming in, farming out or development of certain exploration properties using third party resources;
- The use of development activity and acquisitions to replace and add to reserves;
- The impact of changes in natural gas prices on cash flow after hedging;
- Drilling plans;
- The existence, operations and strategy of the commodity price risk management program;
- The approximate and maximum amount of forward sales and hedging to be employed;
- The Company's acquisition strategy, and the criteria to be considered and the benefits to be derived;
- The impact of Canadian federal and provincial governmental regulation on the Company relative to other issuers of similar size;
- Our treatment under governmental regulatory regimes;
- The goal to sustain or grow production and reserves through prudent management and acquisition;
- The emergence of accretive growth opportunities; and
- The Company's ability to benefit from the combination of growth opportunities and the means to grow through the capital markets.

Iteration's actual results could differ materially from those anticipated in our forward-looking statements as a result of the risk factors set forth below and noted elsewhere in this MD&A which include but are not limited to:

- Volatility in market prices for natural gas;
- Risks inherent in our operations;
- Uncertainties associated with estimating reserves;
- Competition for, among other things: capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- Incorrect assessments of the value of acquisitions;
- Geological, technical, drilling and process problems;
- General economic conditions including fluctuations in the price of natural gas;
- Royalties payable in respect of Iteration's production;
- Governmental regulation of the oil and gas industry, including environmental regulation;
- Fluctuation in foreign exchange or interest rates;
- Unanticipated operational events that can reduce production or cause production to be shut-in or delayed;
- Stock market volatility and market valuations;
- The need to obtain required approvals from regulatory authorities;
- Environmental risks;
- Insurance limitations risks;
- Risks inherent in replacing reserves;
- Reliance on operators and key employees;
- Access to funding and issuance of debt;
- Aboriginal claims; and
- Availability of drilling equipment, access restrictions and cost inflation.

Additional Information on the Company

Other information about the Company, including the Management's Discussion and Analysis and the Annual Information Form for the year ended December 31, 2006, is available through the internet on the Company's SEDAR profile at www.sedar.com.