

# MANAGEMENT'S DISCUSSION AND ANALYSIS

May 7, 2007

The following is Management's Discussion and Analysis ("MD&A") of Iteration Energy Ltd. (the "Company" or "Iteration") operating and financial results as at and for the three month period ended March 31, 2007 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 unaudited consolidated financial statements as at and for the three months ended March 31, 2007 and the 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 2006 Annual Information Form and Management's Discussion and Analysis for the year ended December 31, 2006. 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 Annual Information Form (AIF), is available on-line at [www.iterationenergy.com](http://www.iterationenergy.com) and at [www.sedar.com](http://www.sedar.com).

## ITERATION OVERVIEW

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

## FINANCIAL AND OPERATIONAL HIGHLIGHTS

**The major highlights of the three months ended March 31, 2007 include:**

- Cased 16 net gas wells of the 17 net wells drilled for a success rate of 94%.
- Completed a six well farm-in program at Umbach in northeast British Columbia. 800 boed were brought on production through a new compressor station in April 2007.
- Increased quarter over quarter average production by 12% to approximately 5,850 boed. This represents a 56% increase over the first quarter of 2006.
- Funds from operations of \$12.4 million (\$0.22 per share) increased 49.4 % over the fourth quarter of 2006 and 22.5% compared to the first quarter of 2006.
- Increased the Company's land base to approximately 343,000 net acres, 215,000 of which are undeveloped. This represents an 11% increase over undeveloped lands held at December 31, 2006 and a 134% increase in undeveloped lands compared to March 31, 2006.

## Financial Highlights

	<b>Three months ended March 31,</b>	
	<b>2007</b>	<b>2006</b>
	<b>Total</b>	<b>Total</b>
<b>Financial</b>		
(\$thousands, except as noted)		
Production revenue before royalties	<b>\$23,744</b>	\$17,317
Funds from operations <sup>(2)</sup>	<b>\$12,379</b>	\$10,107
Per Share (\$) <sup>(1)</sup>		
- basic	<b>\$0.22</b>	\$0.21
- diluted	<b>\$0.22</b>	\$0.19
Net earnings (loss)	<b>\$(3,669)</b>	\$2,649
Per Share (\$) <sup>(1)</sup>		
- basic	<b>\$(0.06)</b>	\$0.05
- diluted	<b>\$(0.06)</b>	\$0.05
Royalties, net of ARTC	<b>\$4,857</b>	\$4,282
Production expense	<b>\$4,187</b>	\$1,879
Transportation expense	<b>\$729</b>	\$414
General and administrative	<b>\$1,091</b>	\$777
Stock based compensation expense (recovery)	<b>\$4,500</b>	\$(1,581)
Depletion	<b>\$12,856</b>	\$7,617
Total assets	<b>\$255,654</b>	\$184,019
Capital expenditures:		
Property acquisition, net of dispositions	<b>\$232</b>	\$(150)
Exploration, development and other	<b>\$40,003</b>	\$30,028
<b>Shares outstanding (thousands)</b>		
Common shares	<b>57,774</b>	48,895
Weighted average – basic	<b>57,548</b>	48,895
Weighted average – diluted <sup>(1)</sup>	<b>57,548</b>	52,680
Warrants	<b>5,000</b>	5,000
Stock options <sup>(3)</sup>	<b>5,731</b>	4,888

(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 and 2007, 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 784,500 of these Conditional Options that were granted during the year at a weighted average exercise price of \$4.40 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 to be held 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 784,500 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 to be held 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.

## Operating Highlights

	<b>Three months ended March 31,</b>	
	<b>2007</b>	<b>2006</b>
<b>Operating</b>		
Gas Production		
Total natural gas (bcf)	3.0	1.9
Daily average natural gas (mcf/d)	32,846	21,012
Average price (\$/mcf)	\$7.36	\$8.40
Oil and Liquids Production		
Total oil and liquids (Mbbls)	34	22
Daily average oil and liquids (bbls/d)	376	248
Average price oil and liquids (\$/bbl)	\$58.76	\$64.03
Daily Average Production (boed)	5,851	3,750

<b>Land</b>		
Net undeveloped land holdings (acres)	<b>214,806</b>	91,894
<b>Drilling</b>		
Wells drilled (net)		
Gas	16.0	8.9
Oil	-	1.0
Dry	<u>1.0</u>	<u>1.6</u>
Total	17.0	11.5
Success rate (%)	94.1	86.1

### Quarterly Financial Data

(\$ thousands except per share data)

Quarter ended	2007		2006		2005			
	Mar 31	Dec 31	Sept 30	June 30	Mar 31	Dec 31	Sept 30	June 30
Revenues	\$23,744	\$17,940	\$16,888	\$12,394	\$17,317	\$20,719	\$13,956	\$10,939
Net earnings (loss)	\$(3,669)	\$(3,223)	\$(2,370)	\$(1,472)	\$2,649	4,271	\$1,519	\$473
Net earnings (loss) per common share – basic and diluted (\$)	\$(0.06)	\$(0.06)	\$(0.04)	\$(0.03)	\$0.05	\$0.09	\$0.03	\$0.01

### OPERATING RESULTS

#### Net Earnings (Loss)

Iteration's net loss for the three months ended March 31, 2007 was \$3.7 million, as compared to net earnings of \$2.6 million for the three months ended March 31, 2006. Included in the calculation of net loss for the quarter is stock based compensation expense of \$4.5 million as compared to a recovery of stock based compensation of \$1.6 million for the quarter ended March 31, 2006. Without taking into consideration stock based compensation, Iteration's net earnings for the three months ended March 31, 2007 would have been \$0.8 million, as compared to net earnings of \$1.0 million for the three months ended March 31, 2006. Although production was 56% 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 in east central Alberta and northeastern British Columbia.

#### Production

Average daily production for the three months ended March 31, 2007 increased by 2,101 boed as compared to the three months ended March 31, 2006. This 56% increase includes 905 boed of production from three acquisitions that closed during the first and second quarter of 2006. The production increase was further enhanced by the successful drilling and re-completion of a number of wells in the Company's core areas.

Daily Production <i>Average for the period</i>	Three months ended March 31,		
	2007	2006	% Change
Natural Gas (Mcf/d)	<b>32,846</b>	21,012	56

Crude oil and natural gas

liquids (bbl's/d)	<b>376</b>	248	52
Total (boed)	<b>5,851</b>	3,750	56

The first quarter 2007 capital program, not including acquisitions, was \$40 million and was expected to result in average production of approximately 5,900 boed with a winter exit rate of approximately 6,900 boed. A number of construction delays meant that several new gas wells were not tied in until early April. Production for the quarter was further hampered by a fire at one of our compressor stations in east central Alberta at the end of March. This production is now fully restored, but the average for the quarter was slightly below original expectations at 5,851 boed, and the winter exit rate was not achieved until after the end of the first quarter. Current production is approximately 6,800 boed.

The Company will monitor gas prices over the summer months in order to optimize the timing of its remaining drilling program, and currently expects average production for 2007 to be approximately 6,400 to 6,500 boed.

### Commodity Prices

<b>Industry Benchmarks</b> <i>Average for the period</i>	<b>Three months ended March 31,</b>		
	<b>2007</b>	2006	% Change
Natural gas (Alberta Spot – monthly) Cdn \$/GJ at AECO	<b>7.01</b>	8.79	(20)
Natural gas (Alberta Spot-daily) Cdn \$/GJ at AECO	<b>6.68</b>	7.11	(6)
Natural gas (BC Westcoast Station 2) Cdn \$/GJ	<b>6.75</b>	6.65	2
Edmonton Pentane Cdn\$/bbl	<b>68.73</b>	73.37	(6)
Edmonton Light Crude Cdn\$/bbl	<b>67.74</b>	69.40	(2)
Hardisty Lloydblend Cdn\$/bbl	<b>42.50</b>	30.65	38

<b>Realized Commodity Prices</b> <i>Average for the period</i>	<b>Three months ended March 31,</b>		
	<b>2007</b>	2006	% Change
Natural Gas (\$/Mcf)	<b>7.36</b>	8.40	(12)
Crude oil and natural gas liquids (\$/bbl's)	<b>58.76</b>	64.03	(8)
Total (\$/boed)	<b>45.09</b>	51.31	(12)

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 guidance purposes, based on the April 27, 2007 commodity strip, the Company expects an average 2007 natural gas price of \$7.66 Cdn./gj and a blended price for oil of \$60 Cdn./bbl.

### Revenue

Production revenue was \$23.7 million for the three months ended March 31, 2007, compared with \$17.3 million for the three months ended March 31, 2006. The production revenue increase was due to higher production volumes being offset by somewhat lower commodity prices realized by the Company during the quarter.

<b>Production Revenue before Royalties</b> <i>(\$ thousands)</i>	<b>Three months ended March 31,</b>		
	<b>2007</b>	2006	% Change
Production revenue	<b>23,744</b>	17,317	37

For each of the three months ended March 31, 2007 and 2006, natural gas production accounted for 94% of the Company's total production.

During the quarter, as a means of managing commodity price volatility, the Company entered into the following fixed price contracts for the future physical delivery of natural gas:

<b>Period</b>	<b>Volume</b>	<b>Type</b>	<b>Pricing</b>	<b>Price</b>
Apr 1 – Oct 31, 2007	5,270 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 \$4.9 million for the three months ended March 31, 2007, compared with \$4.3 million for the three months ended March 31, 2006. The relatively little change in royalty expense is the result of increased production offset by lower commodity prices for natural gas.

The decrease in royalty rate per boe is a result of the decrease in commodity price for the comparative period in 2006.

Effective January 1, 2007, the Alberta Royalty Tax Credit program was terminated. Historically, the Company has been eligible for a recovery under the program of approximately \$400,000.

<b>Royalties</b> <i>(\$ thousands except where noted)</i>	<b>Three months ended March 31,</b>		
	<b>2007</b>	2006	% Change
Royalties	<b>4,857</b>	4,282	14
Per boe (\$/boe)	<b>9.21</b>	12.60	(27)
Percentage of revenue (%)	<b>20</b>	25	(20)

For 2007, the Company expects the crown royalty burden to be approximately 21 percent of revenue, reflecting an increase in royalty rate as a result of the termination of the Alberta Royalty Tax Credit program.

### **Production Expenses**

Production expenses were \$4.2 million for the three months ended March 31, 2007, compared with \$1.9 million for the three months ended March 31, 2006. The increase in expenses was due to the following:

- 1) A 56 % increase in production for the quarter as compared to the previous year.
- 2) Inflationary pressure on operating costs throughout the industry.
- 3) Continued efforts to enhance production from existing wells through workovers and facility maintenance. These costs are expensed for financial reporting purposes, even though they have resulted in significant increases in production.

<b>Production expenses</b> <i>(\$ thousands)</i>	<b>Three months ended March 31,</b>		
	<b>2007</b>	2006	% Change
Field operating costs	<b>4,047</b>	1,770	129
Allocated general and administrative costs	<b>140</b>	109	28
<b>Total production expense</b>	<b>4,187</b>	1,879	123

<b>Production expenses per boe</b> <i>(\$ per boe)</i>	<b>Three months ended March 31,</b>		
	<b>2007</b>	2006	% Change
Field operating costs	<b>7.67</b>	5.29	45
Allocated general and administrative costs	<b>0.27</b>	0.32	(16)
<b>Total production expense</b>	<b>7.94</b>	5.61	42

The Company had previously published guidance with respect to expected production expenses for the first quarter of 2007 of \$7.02 per boe. Continued upward pressure on costs, combined with delays experienced during the quarter with respect to tying in production and the compressor fire (which has resulted in a lower than expected average production rate for the quarter) has contributed to the increase in production expense per boe. With continuing pressure on costs, the Company now expects operating costs for 2007 to average approximately \$7.50 per boe.

### Operating Netback

The operating netback (before general and administrative expenses) realized for the three months ended March 31, 2007 was \$26.56/boe versus \$31.87/boe for the three months ended March 31, 2006. The decrease in netback realized was due to a combination of softening natural gas prices and increased operating costs.

<b>Operating Netback</b> <i>(\$/boe)</i>	<b>Three months ended March 31,</b>		
	<b>2007</b>	2006	% Change
Production revenue	<b>45.09</b>	51.31	(12)
Royalties	<b>(9.21)</b>	(12.60)	(27)
Production costs	<b>(7.94)</b>	(5.61)	42
Transportation costs	<b>(1.38)</b>	(1.23)	12
<b>Operating netback</b>	<b>26.56</b>	31.87	(17)

The Company expected a netback of approximately \$27.65/boe for the first quarter. For guidance purposes, based on budgeted commodity prices for the 2007 of \$7.66 Cdn./GJ AECO for natural gas and a blended price for oil of \$60.00 Cdn./bbl, the Company expects an average operating netback (before general and administrative expenses) for 2007 of approximately \$29.29/boe.

### General and Administrative Expenses

Expensed general and administrative costs, excluding stock based compensation expense, increased by 40% to \$1.1 million for the three months ended March 31, 2007, versus \$0.8 million for the three months

ended March 31, 2006, reflecting a 56% increase in production. Total general and administrative costs incurred increased by only 13% during the same period. During the third quarter of 2006, the Company changed the calculation methodology with respect to overhead recoveries and capitalized overhead. Had overhead and capitalized general and administrative expenses been calculated using the same methodology for the three months ended March 31, 2006, overhead recoveries would have been \$44,000 less, and capitalized general and administrative expenses would have been \$248,000 less. This would have resulted in general and administrative expense for the first quarter of 2006 being \$1,069,000 or \$3.17/boe. On a per boe basis, general administrative expense decreased by 10% (35% after taking into consideration the change in calculation methodology for overhead recoveries and capitalized general and administrative expenses) from the comparative quarter in 2006 to \$2.07 per boe.

<b>General and administrative expenses</b> <i>(\$ thousands except where noted)</i>	<b>Three months ended March 31,</b>		
	<b>2007</b>	2006	% Change
General and administrative costs before the following:	<b>1,794</b>	1,593	13
Overhead recoveries	<b>(48)</b>	(70)	(31)
Allocation to production expenses	<b>(140)</b>	(109)	28
Capitalized overhead	<b>(515)</b>	(637)	(19)
General and administrative expense	<b>1,091</b>	777	40
Per boe (\$ / boe)	<b>2.07</b>	2.30	(10)

The Company projected general and administrative expenses of \$2.23 per BOE for the first quarter of 2007. Actual expenses came in lower than expected due to the timing of new staff hires during the quarter. With the projected production volumes, management expects the general and administrative expenses for 2007 to be approximately \$2.05/boe.

### **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 March 31, 2007, a stock based compensation expense of \$4.5 million was recorded based on the increase in value of the outstanding stock options as determined using the March 31, 2007 closing share price, as compared to the closing share price at December 31, 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 March 31, 2007 share price of \$5.75, had all 5,731,189 stock options outstanding been vested, stock based compensation expense and a corresponding liability of \$14.1 million would have been recognized. Of this amount, \$8.6 million has been recognized as a current liability in the March 31, 2007 financial statements.

### **Interest Expense**

Interest expense on current debt (the Company had no long term debt) for the three months ended March 31, 2007 was \$0.5 million as compared to net interest income of (\$0.1) million for the three months ended December 31, 2006. Interest income for the three months ended March 31, 2006 represents income earned

on the cash balances the Company had at that time, offset by \$55,000 of interest expense realized on the Company's credit facility entered into at the end of March 2006. Interest expense for the three months ended March 31, 2007 was as a result of utilizing a portion of a \$65 million credit facility to fund the capital drilling program and acquisitions during the year. The effective interest rate for the first quarter of 2007 on the outstanding Credit Facility was 6%.

<b>Interest expense</b> <i>(\$ thousands except where noted)</i>	<b>Three months ended March 31,</b>		
	<b>2007</b>	2006	% Change
Interest expense	<b>472</b>	55	758
Interest income	-	(167)	(100)
	<b>472</b>	(112)	420
Per boe (\$/boe)	<b>0.89</b>	(0.33)	269

### Depletion

Depletion and depreciation expense was \$12.9 million for the three months ended March 31, 2007 compared to \$7.6 million for the three months ended March 31, 2006. The 69% 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 ended March 31, as compared to the corresponding period in 2006.

<b>Depletion</b> <i>(\$ thousands except where noted)</i>	<b>Three months ended March 31,</b>		
	<b>2007</b>	2006	% Change
Depletion	<b>12,856</b>	7,617	69
Per boe (\$/boe)	<b>24.41</b>	22.57	8

### Capital Expenditures

Exploration and development capital spending for the three months ended March 31, 2007 was \$40.0 million, versus \$29.9 million for the three months ended March 31, 2006.

<b>Capital Expenditures</b> <i>(\$ thousands)</i>	<b>Three months ended March 31,</b>		
	<b>2007</b>	2006	% Change
Acquisition of oil and gas properties, net of disposition proceeds	<b>232</b>	(150)	-
Exploration and development expenditures	<b>40,003</b>	30,028	33
Total	<b>40,235</b>	29,878	35

Total capital expenditures for 2007 are expected to be approximately \$90 million.

### Capital and Liquidity

As an oil and gas company, the Company has a declining asset base and therefore relies on ongoing development and acquisitions to replace production and add additional reserves. Future oil and natural gas

production and reserves are highly dependent on success in exploiting the Company's asset base and in acquiring additional reserves. To the extent the Company is successful or unsuccessful in these activities, funds flow could be increased or reduced.

As at March 31, 2007, the Company had a \$65 million Credit Facility with a Canadian chartered bank. The Company had budgeted to spend \$38 million in the first quarter of 2007 as part of an overall capital program that was heavily weighted to the first quarter winter drilling program. Actual expenditures were 5% higher. 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 deciding on when to restart its drilling program following the annual hiatus caused by lack of surface access. Projected capital spending for 2007, not including acquisitions, is approximately \$90.0 million.

As at March 31, 2007, the Company had drawn \$34.0 million of its \$65 million facility. In addition to this debt, the Company had a working capital deficiency, not including the liability recorded for stock based compensation, of \$23.8 million, for a total net debt of \$57.8 million. The ratio of total net debt at March 31, 2007 to annualized funds flow for the quarter ended March 31, 2007 was 1.19:1. As the Company's capital expenditure program is heavily weighted to the first and fourth quarters of the year, it is expected that this ratio will improve throughout the year. In addition, the Company successfully completed a bought deal equity financing issue on April 26<sup>th</sup>, 2007. Under the financing, the Company issued 7,000,000 common shares at \$5.60 per share, for gross proceeds of \$39.2 million. Net proceeds of this equity issue will be approximately \$36.8 million. Based on current projections, net debt at the end of 2007 is expected to be approximately \$22 to \$24 million.

The Company continues to anticipate 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 May 7, 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.

Projected funds flow for the first quarter of 2007 was previously forecast to be \$14 million. As a result of delays in tying in production during the quarter, which resulted in average production for the quarter being less than projected, combined with higher operating costs and lower commodity prices experienced during the quarter, actual funds flow was \$12.4 million.

For guidance purposes the Company has used projected average prices for 2007 of \$7.66 /GJ AECO for gas and \$60.00/bbl. for Edmonton Light oil. The Company's projected funds flow for 2007 is in the range of \$61 to \$63 million. The impact on the Company's projected 2007 funds flow, of a \$1.00/GJ swing in average AECO price for the remainder of 2007 is approximately \$5.5 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	515
2008	687
2009	344

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### **Related Party Transactions**

For the three months ended March 31, 2007, there were no related party transactions.

### **Outstanding Common Shares**

As at May 7, 2007, there were 64,774,047 common shares, 5,000,000 warrants, and 5,731,189 options (which includes 784,500 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**

As disclosed in the December 31, 2006 annual audited Consolidated Financial Statements, on January 1, 2007, the Company adopted the three new accounting standards that were issued by the Canadian Institute of Chartered Accountants; Handbook Section 1530, *Comprehensive Income*, Handbook Section 3855, *Financial Instruments-Recognition and Measurement*, Handbook Section 3861, *Financial Instruments-Disclosure and Presentation* and Handbook Section 3865, *Hedges*. As required by the new standards, prior periods have not been restated. The adoption of these standards has had no material impact on the Company's net earnings or cashflows. The other effects of the implementation of the new standards are discussed below.

#### Comprehensive Income

Section 1530 of the new standards introduces Comprehensive Income, which consists of net income and other comprehensive income ("OCI"). This section requires 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 statements present net income and each component recognized in other comprehensive income. For the three months ended March 31, 2007, the Company did not recognize any OCI. Should the Company recognize any OCI in the future, the cumulative changes in OCI would be recognized in Accumulated Other Comprehensive Income ("AOCI"), which would be presented as a new category within Shareholders' Equity in the Consolidated Balance Sheet.

#### Financial Instruments – Recognition and Measurement

The Financial Instruments standard, Section 3855 establishes the recognition and measurement criteria for financial assets, financial liabilities and derivatives. All financial instruments are required to be measured at fair value on initial recognition of the instrument, except for certain related party transactions. Measurement in subsequent periods is dependent on whether the financial instrument has been classified as "held-for-trading", "available-for-sale", "held-to-maturity", "loans and receivables", or "other financial liabilities" as defined by the standard.

Financial assets and financial liabilities "held-for-trading" are measured at fair value with changes in those fair values recognized in net earnings. Financial assets "available-for-sale" are measured at fair value, with changes in those fair values measured in OCI. Financial assets "held-to-maturity", "loans and receivables", and "other financial liabilities" are measured at amortized cost using the effective interest method of amortization. The methods used by the Company in determining the fair value of financial instruments is unchanged as a result of implementing the new standard.

Cash and bank indebtedness is designated as “held-for-trading” and are measured at carrying value, which approximates fair value due to the short-term nature of these instruments. Accounts receivable are designated as “loans and receivables”. Bank indebtedness and accounts payable and accrued liabilities are designated as “other liabilities”.

The adoption of the financial instruments standard has resulted in no change in the previous accounting treatment or reporting by the Company.

#### Hedges

One of the new standards dealt with Hedges and the criteria needed to qualify for hedge accounting, as well as the timing for recognition of applicable hedge gains and losses. As the Company had no material fixed price contracts in place at December 31, 2006, there was no effect on the financial reporting of the Company as a result of the implementation of the new standard. With respect to the current fixed price contracts in place, the Company considers them to be future sales contracts at an agreed price with our current gas marketer, which will be satisfied by the future delivery of natural gas. As a result, the Company has not calculated a fair value for the instruments for purposes of recording the contracts on the balance sheet.

#### **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 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 March 31, 2007, 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 budgeted first quarter capital program of \$38 million was expected to result in average production of approximately 5,900 boed with an exit rate of approximately 6,900 boed. The actual capital program for the first quarter of 2007 was \$40 million. Several wells were late being tied in so the resulting average production for the quarter was 5,851 boed. The exit rate was not achieved until after the end of the first quarter. Current production is approximately 6,800 boed.

Based on the April 27, 2007 commodity price strip, the Company expects an average natural gas price for 2007 of \$7.66 Cdn./gj and an average 2007 price for oil of \$60.00 Cdn./bbl. Using these estimates for commodity prices and expected results from currently budgeted activities, the Company expects the following results for 2007:

Average production:	6,400 to 6,500 boed
Capital program:	approximately \$90 million

Operating netback:	approximately \$29 per boe
Funds from operations:	\$61 to \$63 million
Year end net debt:	\$22 to \$24 million

The Company will 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 will evaluate commodity prices for the summer months in order to optimize the start of 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
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## **Advisory – Forward-Looking Information**

This MD&A was prepared on May 7, 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 Unaudited Consolidated Financial Statements for the three months ended March 31, 2007, and the Audited Consolidated Financial Statements, Management's Discussion and Analysis and the Annual Information Form for the year ended December 31, 2006, are available through the internet on the Company's website at [www.iterationenergy.com](http://www.iterationenergy.com) and on the Company's SEDAR profile at [www.sedar.com](http://www.sedar.com).