



## MANAGEMENT'S DISCUSSION AND ANALYSIS

September 30, 2006

The following Management's Discussion and Analysis ("MD&A") was prepared as of November 21, 2006 and should be read in conjunction with the unaudited consolidated financial statements for the three-month and nine-month period ended September 30, 2006 and the MD&A and audited consolidated financial statements for the year ended December 31, 2005.

In conformity with the Canadian Securities Administrators National Instrument 51-101 ("NI 51-101"), natural gas volumes have been converted to equivalent barrels of oil ("boe") using a conversion ratio of six thousand cubic feet ("mcf") to one boe.

This MD&A contains forward-looking statements. Forward-looking statements are based on current expectations that involve a number of risks and uncertainties, which could cause actual events or results to differ materially from those reflected in the MD&A. Forward-looking statements are based on the estimates and opinions of Greentree's Management at the time the statements were made.

Included in the MD&A are references to the term "cash flow". This term is not defined by Generally Accepted Accounting Principles ("GAAP") in Canada and consequently is referred to as a non-GAAP measure. Reported amounts may not be comparable to similarly titled measures reported by other companies. Cash flow should not be considered an alternative to, or more meaningful than, cash provided by operating activities as determined in accordance with Canadian GAAP.

Greentree Gas & Oil Ltd. ("Greentree" or the "Company") is a junior explorer and producer of natural gas and oil in southwestern Ontario and trades under the symbol 'GGO' on the TSX Venture Exchange. Greentree currently has 36,811,961 shares outstanding.

### PRODUCTION, REVENUES AND ROYALTIES

On an overall basis, production in Q3-2006 was 9,092 boe as compared to 8,547 boe for Q3-2005, representing an increase of 6.4%. Gross revenue from natural gas and crude oil in Q3-2006 of \$440,941 was 18.6% lower than the \$554,006 posted for Q3-2005 due mainly to weaker prices and reduced oil production. However, gross revenue from gas and oil sales in the first nine months of 2006 was only \$8,429 less than for the same period in the prior year. Total Q3-2006 revenue of \$450,331 (Q3-2005 - \$557,205) consisted of sales of natural gas and crude oil, and to a lesser extent, gas processing and transportation revenue, natural gas by-product sales and other miscellaneous revenue.

#### NATURAL GAS

Natural gas production increased by approximately 15.2% in Q3-2006 to 48,321 mcf as compared to 41,942 in Q3-2005. Production in the first nine months of 2006 increased by almost 10% as compared to the same period in 2005. The increase in production is mainly attributable to new wells in West Lorne and Innerkip and upgrades to the Charlotteville field gathering system.

Lower natural gas prices more than offset the effects of increased production, resulting in 17.8% lower natural gas revenues in Q3-2006 as compared to Q3-2005. The Company received an average price of \$7.53/mcf for its natural gas in Q3-2006, compared to \$10.56/mcf in Q3-2005. However, total natural gas revenues for the first nine months of 2006 slightly exceeded those in the same period of 2005.

## CRUDE OIL

Crude oil production decreased from 1,557 bbls in Q3-2005 to 1,039 bbls in Q3-2006. This large decline was attributable to continued shutdowns of the Rodney Unit 3 field in order to implement substantial infrastructure changes and provide refurbished facilities. As a result of these changes, Management expects more consistent production from this field beginning in 2007.

Crude oil revenues decreased by \$34,122, from \$111,257 in Q3-2005 to \$77,135 in Q3-2006, again mainly due to the shutdowns described above. Prior to Q3-2006, crude oil revenues in the first half of 2006 were approximately equal to those for the same period in 2005. Prices remain strong, with the average price for the Company's oil in Q3-2006 at \$76.25/bbl as compared to \$73.29/bbl in Q3-2005.

## ROYALTIES

Royalties include both freehold and gross overriding payments. Royalties as a percentage of gas and oil revenue was approximately 12.8% in Q3-2006 as compared to approximately 10.9% in Q3-2005.

## OPERATING EXPENSES

Operating expenses were higher (approximate 14.1% increase) in Q3-2006 as compared to Q3-2005. Accounting for part of the increase were additional repairs in the Rodney Unit 3 oil field conducted in areas where a major overhaul was not considered necessary. However, operating expenses were down 13.2% in Q3-2006 when compared to the previous quarter and well within normal levels. A positive trend in operating efficiency has occurred during 2006. On a per-barrel equivalency basis, operating costs per barrel of oil equivalent in Q2-2006 were 4.8% lower as compared to Q1-2006, and 16.0% lower when comparing Q3-2006 to Q1-2006.

## GENERAL & ADMINISTRATIVE EXPENSES

As anticipated, general and administrative costs returned to normal levels in Q3-2006 and were on par with Q3-2005. As discussed in the Q2-2006 MD&A, general and administrative costs were abnormally high in that quarter due to generally non-regular or non-recurring items. Removing the effects of these items, normalized general and administrative costs for the nine months ended September 30, 2006 were \$278,839 (average of \$92,946 per quarter), which is within expected levels and down considerably from general and administrative costs incurred in the nine-month period ending September 30, 2005.

## DEPLETION AND DEPRECIATION EXPENSES

### DEPLETION

The main factors that affect the calculation of depletion are the level of production, net book value of assets subject to depletion, and estimated remaining reserves. Depletion moves in direct proportion to the first two (i.e., the higher the level of production and the higher the average net book value of depletable assets over a given period, the higher the depletion expense). On the other hand, depletion expense is inversely proportional to the average level of estimated proven reserves over a given period (i.e., the higher the level of estimated reserves, the lower the depletion expense). As a result of a combination of these factors, depletion expense in Q3-2006 was \$187,821, compared to \$177,989 in Q3-2005, an increase of 5.5%.

## DEPRECIATION

Because equipment and certain other assets are depreciated on a straight-line basis, depreciation expense for a given class of assets has more of a direct relationship with the average net book value of the related depreciable assets. As the Company uses depreciation rates varying from 10% to 30%, fluctuations may arise when comparing certain periods. For example, a significant percentage increase in depreciation expense may occur if the Company were to purchase a disproportionately larger amount of assets in a higher-rate class. Depreciation expense in Q3-2006 was \$11,206, compared to \$22,695 in Q3-2005.

## CASH FLOW

Cash flow, as commonly used in the oil and gas industry, represents net income before depletion and depreciation, future income taxes and other non-cash expenses. The difference between “cash flow” and “cash flow from operating activities” is that cash flow represents cash that has been received, or will be received in the future, due to the revenues generated during the period, net of cash that has been paid, or will be paid in the future, as a result of expenses incurred during the period. On the other hand, the latter term measures the actual cash collection and cash payments relating to operating activities that took place during the period. The following table reconciles the Company’s cash flow from operating activities to cash flow for the three-month periods ended September 30, 2006 and September 30, 2005.

<b>3-Month period ended:</b>	<b>September 30, 2006</b> <b>(\$)</b>	<b>September 30, 2005</b> <b>(\$)</b>
Cash flow from operating activities, as reported	(197,302)	(208,779)
Changes in non-cash operating working capital items	264,789	420,512
Cash flow	67,487	211,733

Management continues to carefully monitor cash flow in order to settle old outstanding accounts, improve its working capital position, and meet commitments. The Company has been cash flow positive in its last six quarters.

## CAPITAL EXPENDITURES AND PROJECTS

The Company invested \$310,082 in property, plant and equipment during Q3-2006, as compared to \$56,160 during Q3-2005. Capital expenditures incurred during Q3-2006 consisted primarily of drilling, completion and recompletion costs (\$160,655), facilities and infrastructure costs (\$60,168), geological expenditures (\$36,022), lease and land costs (\$35,923), and automotive equipment costs (\$15,296).

During Q3-2006, drilling commenced in Greentree’s Rodney South oil pool. The initial phase of the project entails the drilling of eight injection wells, which will be equipped with Wavefront Energy and Environmental Systems Inc.’s (“Wavefront”) patented fluid flow technology, and two horizontal production wells. The eight injection wells powered by Wavefront technology are also expected to enhance production in eight existing vertical producers and one horizontal producer. At the time of writing, five injection wells have been drilled. Pursuant to the terms of the agreement, Greentree will retain a 30% interest in the production from the Rodney South wells once the first new producing well is drilled, completed, equipped and tied-in, and a 50% interest subsequent to Wavefront recouping its capital investment. The initial phase of the project is being undertaken at no capital cost to Greentree.

Subsequent to Q3-2006, the Company has commenced an aggressive fall/winter drilling program, the progress of which is discussed below in the “Outlook” section of this MD&A.

## LIQUIDITY AND CAPITAL RESOURCES

As at September 30, 2006, the terms of the Company's operating facility consisted of a revolving line of credit for a maximum unrestricted amount of \$2,400,000 with no monthly reductions. The Company has pledged as security a \$10 million debenture with a floating charge over all assets of the Company with a negative pledge and undertaking to provide fixed charges on the Company's major producing petroleum and natural gas reserves at the request of the lender, a general assignment of book debts, insurance assignment showing the lender as first loss payee, an assignment of revenues and monies under material contracts, and a guarantee from Southwest Petroleum Explorations Inc., supported by debenture security.

As at September 30, 2006, the Company's trade payables and accrued liabilities were \$664,734, however approximately \$150,000 of this amount is in respect of charge-backs on the Rodney South project (i.e. offset on the asset side by approximately \$150,000 of receivables from Wavefront), resulting in a continued improvement in short-term debt levels. As at September 30, 2006 the Company is in compliance with the working capital covenants of its lending institution.

During Q3-2006, the Company closed two private placements of capital stock on both a flow-through and non-flow-through basis, for gross proceeds totaling approximately \$1.2 million. Details of the private placements are provided in note 10 to the September 30, 2006 consolidated financial statements. Management is currently in negotiations to raise additional risk capital by the end of the year in order to fund further drilling.

## RELATED PARTY TRANSACTIONS

A relationship exists between the Company and a law firm of which a partner is a director and shareholder of the Company. During Q3-2006, professional fees of \$23,321 were incurred for services provided by the law firm. The balance due to the law firm as at September 30, 2006 was \$289,656.

## ADDITIONAL DISCLOSURES

### CRITICAL ACCOUNTING ESTIMATES

Critical accounting estimates require Management to make assumptions regarding matters that are highly uncertain at the time the estimate is made and have a material impact on the financial condition of the Company. A comprehensive discussion of the Company's significant accounting policies may be found in note 3 to the September 30, 2006 consolidated financial statements.

**Reserves.** The Company's natural gas and oil reserves were evaluated and reported on by the independent petroleum engineering and geological consulting firm of Dobson Resource Management Ltd., which evaluated the Company's reserves as at December 31, 2005. The estimation of reserves is a subjective process. Forecasts are based on engineering data, projected future rates of production and the timing of future expenditures, all of which are subject to numerous uncertainties and various interpretations. The Company expects that its estimates of reserves will change with updated information from the results of future drilling, testing or production levels. Such revisions could be upwards or downwards. Reserve estimates have a material impact on depletion and depreciation expense, asset retirement costs and impairment expense, which could possibly have a material impact on consolidated net income.

**Depletion.** Capitalized costs and estimated future expenditures to develop proved reserves, including abandonment costs, are depleted based on the proportion of estimated proved oil and natural gas reserves produced during the year compared to total proved reserves. Investments in unproved properties and major development projects are not amortized until proved reserves associated with the projects can be determined or until impairment occurs. If it is determined that properties are impaired, the amount of the impairment is added to the capitalized costs to be amortized.

**Impairment.** In applying the full cost method of accounting, the Company periodically calculates a ceiling, or limitation on the amount that petroleum and natural gas properties may be carried for on the balance sheet. An impairment exists if the undiscounted future net cash flows from proved reserves at future commodity prices plus the cost of undeveloped properties is less than the carrying value of the capitalized costs. If an impairment is found to exist, the impaired properties are written down to their fair value. The fair value of the assets is calculated based on future net cash flows from proved plus probable reserves, discounted at a 10% rate using future commodity prices, plus the cost of undeveloped properties. An impairment may result in a material loss for a particular period; however, future depletion and depreciation expense would be reduced. Assumptions about reserves and future prices are required to calculate future net cash flows. The assumptions made to estimate reserves have been previously discussed. There is significant uncertainty regarding forecasting future commodity prices due to economic and political uncertainty. Future prices are derived from a consensus of price forecasts among recognized reserve evaluators. Estimates of future cash flows assume a long-term price forecast and current operating costs per boe plus an inflation factor. It is difficult to determine and assess the impact of a decrease in proved reserves on impairment. The relationship between reserve estimates and the estimated undiscounted cash flows, and the nature of the impairment test, is complex.

**Asset Retirement Obligations.** The Company is required to remove production equipment, batteries, pipelines, gas plants and restore land at the end of natural gas and oil operations. The Company estimates these costs in accordance with existing laws, contracts and other policies. These obligations are initially measured at fair value, which is the discounted future value of the liability. These costs are also capitalized as part of the cost of the related assets and amortized over the useful life of the assets.

An annual increase to the liability will be recorded to recognize the passage of time and the impending settlement of the obligation. The liability will be impacted by any changes in the assumptions used in the asset retirement obligation calculation. Adjustments to the estimate will be recorded as an expense on the consolidated statements of earnings.

The asset retirement obligation calculations were derived from typical industry experience and practices. The deemed asset retirement obligation liability for wells and facilities is the sum of the calculated abandonment and reclamation liabilities adjusted for designated status as active, inactive, abandoned, or problem site.

Estimating future asset removal costs is difficult and requires Management to make estimates and judgments because most of the removal obligations are many years in the future and contracts and regulations often have vague descriptions of what constitutes removal. Asset removal technologies and costs are constantly changing, as well as regulatory, political, environmental, safety and public relations considerations. As a result, it is not possible to provide a reasonable analysis of the impact that changes in removal costs would have on the asset retirement obligation.

## **OPERATIONAL AND FINANCIAL CONDITIONS AND RISKS**

Greentree's operations are subject to risks normally associated with the natural gas and oil industry. Oil and natural gas exploration involves many risks, which even a combination of experience, knowledge and careful evaluation may not be able to overcome. There is no assurance that commercial quantities of natural gas and crude oil will be discovered by the Company. The marketability of natural gas and crude oil acquired or discovered will be affected by numerous factors beyond the control of the Company. These factors include reservoir characteristics, the proximity and capacity of oil and natural gas pipelines and processing equipment and government regulation.

The Company is exposed to financial risks including interest rate risk on its operating facility, and commodity prices and expenditure costs shifting due to changes in market conditions. Commodity prices are driven by supply, demand and market forces outside the Company's influence. Greentree's ability to raise additional capital will depend upon a number of factors, such as general economic and market conditions that are beyond its control.

## QUARTERLY INFORMATION

<b>Quarterly Data (unaudited)</b> <b>Year Ended December 31, 2006</b>	<b>1<sup>st</sup></b> <b>Quarter (\$)</b>	<b>2<sup>nd</sup></b> <b>Quarter (\$)</b>	<b>3<sup>rd</sup></b> <b>Quarter (\$)</b>
Gas and oil revenues	543,020	469,813	440,941
Normalized earnings before interest, taxes, depreciation and amortization (EBITDA)*	185,493	94,268	131,175
Basic & diluted earnings (loss) per share	0.01	(0.01)	(0.00)
Cash flow	129,362	82,187	67,487
Operating netback per boe**	31.60	23.12	23.08
Operating and G&A netback per boe***	21.22	12.48	13.39
Production (boe/d)	97	102	99

<b>Quarterly Data (unaudited)</b> <b>Year ended December 31, 2005</b>	<b>1<sup>st</sup></b> <b>Quarter (\$)</b>	<b>2<sup>nd</sup></b> <b>Quarter (\$)</b>	<b>3<sup>rd</sup></b> <b>Quarter (\$)</b>	<b>4<sup>th</sup></b> <b>Quarter (\$)</b>
Gas and oil revenues	400,164	508,033	554,006	834,438
Normalized earnings before interest, taxes, depreciation and amortization (EBITDA)*	35,173	143,052	257,009	393,082
Basic & diluted earnings (loss) per share	(0.01)	(0.00)	(0.00)	(0.03)
Cash flow	(5,347)	86,029	211,733	152,894
Operating netback per boe**	23.21	30.43	39.83	56.57
Operating and G&A netback per boe***	4.44	15.34	29.81	41.84
Production (boe/d)	87	102	94	102

<b>Quarterly Data (unaudited)</b> <b>Year ended December 31, 2004</b>	<b>1<sup>st</sup></b> <b>Quarter (\$)</b>	<b>2<sup>nd</sup></b> <b>Quarter (\$)</b>	<b>3<sup>rd</sup></b> <b>Quarter (\$)</b>	<b>4<sup>th</sup></b> <b>Quarter (\$)</b>
Gas and oil revenues	393,049	421,100	512,284	530,400
Normalized earnings/(loss) before interest, taxes, depreciation and amortization (EBITDA)*	(17,759)	(263,731)	(245,944)	(46,673)
Basic & diluted earnings (loss) per share	(0.00)	0.01	(0.02)	(0.10)
Cash flow	(18,107)	(322,342)	(292,266)	(80,211)
Operating netback per boe**	12.92	(4.71)	22.74	26.15
Operating and G&A netback per boe***	(2.15)	(32.70)	(23.42)	(5.82)
Production (boe/d)	91	89	114	104

\* Normalized EBITDA eliminates the effect of unusual, irregular or non-recurring items.

\*\* Operating netback is calculated as oil and gas revenues less royalties and normalized operating expenses.

\*\*\* Operating and G&A netback is calculated as oil and gas revenues less royalties, less normalized operating expenses, and normalized general and administrative expenses.

In 2006, gas and oil revenues show a decreasing trend as natural gas prices in the first nine months have not been as strong as in 2005 and crude oil output declined due to Rodney Unit 3 shutdowns. EBITDA, cash flow and netbacks generally showed a positive trend during 2005 and downward trend during the first three quarters of 2006 largely due to considerable declines in natural gas prices. Despite the decline in prices in 2006, netbacks and cash flow continue to be positive.

## RESPONSIBILITY FOR FINANCIAL STATEMENTS

The accompanying consolidated financial statements for Greentree Gas & Oil Ltd. have been prepared by Management in accordance with Canadian GAAP consistently applied. The most significant of these accounting principles have been set out in the statements. These statements are presented on the accrual basis of accounting. Accordingly, a precise determination of many assets and liabilities is dependent upon future events. Therefore, estimates and approximations have been made using careful judgment.

Recognizing that the Company is responsible for both the integrity and objectivity of the consolidated financial statements, Management is satisfied that these consolidated financial statements have been fairly presented.

## OUTLOOK

In the Company's Q1-2006 MD&A, Management identified a number of priorities on which it had reported some progress in the Q2-2006 MD&A. Further updates on these priorities and projects is provided below.

- 1) **Haldimand County "Deep Gas" Prospect.** Greentree is currently drilling a deep wildcat exploratory location on an industrial property (approximately 6,500 contiguous acres) based on a seismic anomaly, which was identified with a recently acquired 37.5 km 2D program. GGOL#67 is targeting the prolific Ordovician Trenton-Black River hydrothermal dolomite play and will also evaluate gas potential in three overlying formations (Silurian Thorold, Grimsby and Whirlpool) and one deeper formation (Cambrian). Greentree will drill the test well location at its sole cost and expense and will earn 100% of the production revenues. The industrial property owner has the option to participate 50% in the net revenues from production, but only once 100% of all drilling, completion, equipping and tie-in costs have been recovered by Greentree.
- 2) **Norfolk County Properties.** Greentree has cased the first two exploration wells of a three well program in Norfolk County targeting the Silurian Thorold formation. The third location has been temporarily postponed due to poor ground conditions. One of the two wells is expected to be tied into the sales line in early December and for the near term does not require a stimulation. The second well is currently being evaluated and is situated relatively close to a Greentree sales line.
- 3) **Tilbury West Prospect.** Greentree has a rig contracted to drill a deep light oil prospect in Tilbury West Township, Essex County commencing in late November, 2006. The site is permitted and the well location access has been prepared for the contracted rig. GGOL#71 offsets a Talisman horizontal oil producer by approximately 300 meters along a seismically-defined Trenton-Black River anomaly. The Talisman well (completed in 2001) reported an initial test flow of approximately 175 bbls/d and recent production reports indicate production is in the 1 to 2 bbls/d range. The potential productive interval is approximately 125 meters in thickness and the seismic data indicates the main pay interval may be located approximately 50 meters below where the Talisman discovery well was drilled horizontally through the reservoir section.
- 4) **West Lorne Prospect.** Greentree has staked a location and contracted a rig to drill an exploratory test in Aldborough Township, Elgin County. GGOL#72 will be located along a prospective depositional fairway of the Silurian Grimsby sandstone. The well location offsets an Imperial Oil deep hole which had an interpreted four meters of potential bypassed gas pay in the Grimsby sandstone. Two wells to the northwest of the location had initial flow rates of 1.77 and 1.13 MMcf/d and six recent wells to the southeast of GGOL#72 reported initial flow rates in the 1.0 to 4.2 MMcf/d range from the Grimsby sandstone.
- 5) **Corporate Finance.** Management is currently in negotiations with several interested parties to obtain additional financing by the end of 2006 in order to meet winter drilling program targets.

Overall, the Company is engaged in one its most aggressive growth programs to date and will continue to keep stakeholders apprised on a regular basis on the progress of these projects.