ROOSTER ENERGY LTD.

Management Discussion and Analysis
December 31, 2013

This management discussion and analysis ("MD&A") of Rooster Energy Ltd. ("Rooster" or, the "Company") reflects its December 31, 2013 financial results and operations as well as developments following December 31, 2013 through the date of this MD&A. This MD&A should be read in conjunction with the Company's audited annual consolidated financial statements and related notes as at and for the years ended December 31, 2013 and 2012, which were prepared in accordance with International Financial Reporting Standards ("IFRS"), as issued by International Accounting Standards Board ("IASB"). All dollar amounts are stated in U.S. dollars, unless otherwise noted.

Overview

The Company is an independent oil and natural gas exploration and production company focused on the development of resources in the shallow waters of the Gulf of Mexico. At December 31, 2013, our primary assets consist of operating rights interests and/or record title interests in 14 oil and gas leases or blocks granted by the United States of America that contain 19 gross producing oil and/or natural gas wells.

Our core business and strategy is focused on the development of our inventory of oil and natural gas leases and the production and sale of oil and natural gas from those leases. The Company has identified drilling locations to which it will selectively allocate capital by applying an intensive screening analysis in order to maximize potential financial returns considering associated risks, among other factors. We are the operator of the majority of our properties, daily oil and gas production, and almost all identified potential drilling prospects; therefore we can control, to the best of our ability, the timing, costs, and drilling procedures.

Finding and economically developing oil and natural gas reserves is critical to our financial success. Key drivers of performance in the business for the Company are the: (i) ability to successfully discover, develop, and exploit commercial oil and natural gas reserves on our properties; and (ii) the ability to optimize profitability from the operation of our properties. Further, our ability to successfully discover, develop, and exploit properties is a function of, among other things: (i) our ability, or the ability of our partners that operate wells in which the Company is a non-operating interest owner, to retain drilling rigs, drillers, personnel and supplies to carry out drilling and workover operations in a professional and cost effective manner; (ii) the ultimate results of such drilling or workover operations; (iii) the availability, on commercially reasonable terms, of transportation, storage, handling, processing and other facilities to service producing wells; and (iv) our ability to finance the costs of such operations. Our ability to optimize profitability from the operation of producing properties is a function of, among other things: (i) lease operating expenses, which may be beyond our control, particularly on wells operated by third parties; (ii) volumes of oil and natural gas produced; and (iii) prevailing prices for oil and natural gas.

The Company was incorporated in British Columbia in 1988. On April 30, 2012 the Company completed the acquisition of all of the membership interest in Rooster Energy, L.L.C. ("Rooster"). The transaction was treated as a reverse acquisition of the Company by Rooster. The Company conducts business through its wholly owned subsidiaries, Rooster Energy, L.L.C., Rooster Petroleum, LLC, Rooster Oil & Gas, LLC, and Probe Resources US Ltd.

Our common stock trades on the TSX Venture Exchange under the ticker symbol "COQ". The terms "the Company", "we", "us", "our" and similar terms, when used in the present tense, prospectively or for historical periods since April 30, 2012 refer to us and our subsidiaries, and for historical periods prior to May 1, 2012 refer to Rooster Energy, L.L.C. and its wholly owned subsidiaries, Rooster Petroleum, LLC, and Rooster Oil & Gas, LLC, unless the context indicates otherwise.

Review of Fiscal Year 2013

The Company produced 799,337 barrels of oil equivalent ("BOE") in the year ended December 31, 2013, compared to 821,354 BOE produced in the year ended December 31, 2012, a 3% annual decline. The lower sales volumes were primarily the result of natural production declines at its largest fields, as the Company has not brought any new wells online since July, 2012. In 2013, the Company generated EBITDAX of $23,711,324 compared to $16,721,070 generated in 2012, a 42% annual increase. Lower production volumes were offset by higher realized prices, primarily the result of a shift in the Company's production mix to a higher percentage of liquids (for calculation, see Appendix A).

The Company recorded a net loss of $2,033,851 in 2013 compared to a net loss of $3,687,669 recorded in 2012. However, the net losses of both 2013 and 2012 were impacted by several non-cash charges. Funds generated from operations (including dry hole costs) totaled $14,378,569 in 2013, compared to $12,689,614 in 2012, an increase of $1,688,955 (see Non-IFRS Financial measurements on page 10).

Proved and probable reserves totaled 9,804,086 BOE (48% liquids) at year-end 2013, compared to 11,024,896 BOE booked at year-end 2012. Proved reserves, which were 81% developed, totaled 2,828,559 BOE (69% liquids). The net present value of proved and probable reserves, discounted at 10% (NPV-10%), totaled $265,882,600. The decline in the Company's proved and probable reserves were primarily due to a write-down of reserves at Grand Isle 70.

In January, 2014, the Company recompleted the Vermilion 376 #A-1 well (100% working interest ("WI") owned by the Company) in the Q1 sand; the well is currently producing approximately 1,300 thousand cubic feet per day (MCFPD). In April, 2014, the Company added compression equipment to increase production at Grand Isle 70 (100% working interest owned by the Company); the field is currently producing approximately 3,500 MCFGPD. In June, 2014, the Company expects to complete a tubing exchange in the Eugene Island 28 #A-3 well (50% WI) and, if successful, bring the well back on production.

The Company drilled and completed its operated High Island A-494 #B-4 well, in which it owns 75% WI, in two separate geologic horizons. The secondary objective zone was flow tested but developed behind casing communication with a deeper, water producing sand. This communication, confirmed by recorded pressure, appears to be the result of poor cement bonding across the zone of interest. The Company believes a cement squeeze operation can rectify this behind pipe communication and a successful completion can be accomplished. The squeeze job will also facilitate a future completion of two additional, newly discovered, behind pipe hydrocarbon bearing reservoirs.

The Company has made several attempts to establish flow in the primary, stratigraphically deeper target that wireline logged hydrocarbons in three sands. After multiple diagnostic operations that measured pressure, temperature and flow dynamics, it has been determined that the primary completion is partially plugged off and not in full communication with the productive reservoir. Both oil and gas have been recovered from this completion however sustained flow has yet to be achieved. The Company is currently evaluating its options including acidizing, perforating the production tubing above the completed interval to establish improved communication with the reservoir. The Company anticipates that if efforts to achieve sustained flow from the primary target are unsuccessful, we may attempt to workover the secondary objective zone and or re-drill the well. There are no proven reserves in the well. However there are probable reserves assigned to the well in the Company's 51-101 reserve report dated at December 31, 2013.

Business

At December 31, 2013, the Company's interests in oil and natural gas leases consisted of ownership in 14 leases or blocks, all of which are located in the shallow waters (< 400' water depth) of the Gulf of Mexico adjacent to the states of Louisiana and Texas. In Q4 2013, the Company's net crude oil sales averaged 688 barrels per day (BOPD), net natural gas liquids (NGLs) sales averaged 100 barrels of oil equivalent per day (BOEPD), and net natural gas sales averaged 5,030 thousand cubic feet per day (MCFPD) (or 838 BOEPD); in aggregate, total crude oil, NGL, and natural gas sales averaged 1,626 BOEPD. The Company's four primary operated properties located at Vermilion 376, Eugene Island 28, Grand Isle 70 and East Cameron 36and 37, comprised 94% of Q4 2013 sale volumes.

On March 19, 2014, the Company submitted the high bid (approximately $172,000) on an oil and gas lease covering Ship Shoal 172 at the Central Gulf of Mexico Federal Lease Sale 231. If awarded, the Company will have an inventory of five (5) primary term leases with potential future drilling locations.

Selected Annual Information

The following financial and operating data are selected information for the Company for the three (3) most recently completed financial years, reflecting the results of operations of the Company for the years ended December 31, 2013, 2012, and 2011:

Financial	For the years ended December 31,		
	2013	2012	2011
Total revenues	$ 41,048,401	$ 34,221,262	$ 21,001,250
Operating income (loss)	3,239,373	2,448,865	4,477,521
Unrealized gain (loss) on financing warrants	(25,000)	1,317,000	-
Net interest expense and financing costs	(5,961,224)	(2,165,534)	(952,237)
Deferred income tax expense (recovery)	(713,000)	(5,288,000)	-
Net income (loss)	(2,033,851)	(3,687,669)	3,525,284
Income (loss) per share - basic	(0.02)	(0.04)	0.04
Income (loss) per share - diluted	(0.02)	(0.04)	0.04
Total assets	107,524,633	96,577,261	39,965,322
Total long-term financial liabilities	22,178,904	54,331,401	13,008,253
Cash dividends per share	-	-	-

Results of Operations

The following table summarizes production volumes, average sales prices, operating costs, and net income (loss) for the three and years ended December 31, 2013 and 2012:

	For the three months ended December 31,		For the twelve months ended December 31,	
	2013	2012	2013	2012
Sales				
Oil (Bbl)	63,260	78,242	289,419	218,408
NGL (Bbl)	9,193	19,592	33,874	57,586
Natural gas (Mcf)	462,735	969,198	2,856,270	3,272,161
Total Oil (BOE) [(a)]	149,575	259,368	799,337	821,354
Total Oil (BOE/day) [(a)]	1,626	2,819	2,190	2,244
Oil ($/Bbl)	$ 98.12	$ 103.48	$ 104.67	$ 104.79
NGL ($/Bbl)	33.62	30.12	27.76	32.64
Natural gas ($/Mcf)	3.48	3.48	3.44	2.88
Summary statement of income				
Revenue	$ 8,128,381	$ 12,061,865	$ 41,048,401	$ 34,221,262
Expenses				
Lease operating costs	2,934,138	3,497,410	12,349,985	11,909,649
Depreciation and depletion	1,901,412	3,255,396	8,708,209	8,417,986
Exploration and evaluation	321,368	4,037,856	2,483,731	3,734,313
Plug and abandonment [(b)]	-	-	-	2,362,072
General and administrative	1,249,273	1,181,813	4,987,092	3,356,020
Transaction costs	-	33,145	-	812,451
Bad debt expense	88,613	302,337	2,885,059	302,337
Impairment expense	4,802,756	(425,866)	4,802,756	(82,080)
Asset retirement expense	586,305	452,351	586,305	452,351
Stock-based compensation	410,509	217,413	1,005,891	507,298
Total costs and expenses	12,294,375	12,551,855	37,809,028	31,772,397
Operating income (loss)	(4,165,994)	(489,990)	3,239,373.23	2,448,865
Unrealized loss on financing warrants	518,000	1,317,000	(25,000)	1,317,000
Finance expenses [(c)]	(1,535,153)	(1,331,847)	(5,961,224)	(2,165,534)
Income (loss) before tax expense	(5,183,147)	(504,837)	(2,746,851)	1,600,331
Deferred tax expense (recovery)	(1,789,000)	5,288,000	(713,000)	5,288,000
Income (loss)	(3,394,147)	(5,792,837)	(2,033,851)	(3,687,669)
Income (loss) per share				
Basic	(0.03)	(0.05)	(0.02)	(0.04)
Diluted	(0.03)	(0.05)	(0.02)	(0.04)
Weighted average shares outstanding [(d)]				
Basic	105,468,323	105,465,823	105,466,967	100,776,437
Diluted	106,337,618	105,465,823	105,466,967	100,776,437
Capital expenditures	$ 10,072,146	$ 5,466,310	$ 36,361,558	$ 32,208,705
EBITDAX [(e)]	$ 3,944,969	$ 7,349,497	$ 23,711,324	$ 16,721,070

(a) Gas volumes are converted to BOE on the basis of 6 Mcfe per 1 barrel.

(b) Plug and abandonment expense in 2012 of $2,362,072 includes a non-cash charge of $940,000.

(c) Finance expenses include accretion for asset retirement obligations.

(d) The weighted average number of common shares for 2012 is weighted for the before and after merger shares and for 2011 is based on 1,000 units.

(e) EBITDAX is a non-IFRS measure commonly used in the oil and gas industry. Such measures do not conform to IFRS and may not be comparable to those reported by other companies nor should they be viewed as an alternative to other measures of financial performance calculated in accordance with IFRS. The Company defines EBITDAX as net income before finance expense, taxes, depreciation, depletion, amortization, accretion, exploration and evaluation expense, bad debt, impairments, stock-based compensation, and the non-cash portion of plug and abandonment expense. (See Appendix A.)

Sale Volumes

Crude oil sales totaled 63,260 barrels (688 BOPD) in Q4 2013 compared to 78,242 barrels (850 BOPD) in Q4 2012, a decline of 14,982 barrels (19%). For the year ended December 31, 2013, crude oil sales totaled 289,419 barrels (793 BOPD) compared to 218,408 barrels (597 BOPD) for the year ended December 31, 2012, an increase of 71,011 barrels (33%). The Company completed a three-well drilling program at Vermilion 376 in June, 2012, which contributed to higher production volumes for the year ended December 31, 2013. However, with no new wells brought online since, natural production declines – particularly at Vermilion 376 and Grand Isle 70 – led to a year-over-year decline in sale volumes in Q4 2013.

Natural gas liquid (NGL) sales totaled 9,193 BOE (100 BOEPD) in Q4 2013 compared to 19,592 BOE (213 BOEPD) in Q4 2012, a decline of 10,399 BOE (53%). For the year ended December 31, 2013, NGL sales totaled 33,874 BOE (93 BOEPD) compared to 57,586 BOE (157 BOEPD) for the year ended December 31, 2012, a decline of 23,712 BOE (41%). Lower sales primarily reflect production declines at Grand Isle 70 and Vermilion 376. At Grand Isle 70, the #A-1 completion was shut in after reaching line pressure in March, 2013, and has been producing intermittently while waiting on compression. At Vermilion 376, the #A-3 well was largely a gas well when it commenced production in June, 2012 (76% of its production was natural gas in Q3 2012). However, in late-2012 the production mix began to change, with dropping gas production offset by rising crude oil production (93% of its production was crude oil in Q4 2013), which led to lower gas sales from year-ago levels.

Natural gas sales totaled 462,735 MCF (5,030 MCFPD) in Q4 2013 compared to 969,198 MCF (10,535 MCFPD) in Q4 2012, a decline of 506,463 MCF (52%). For the year ended December 31, 2013, natural gas sales totaled 2,856,270 MCF (7,825 MCFPD) compared to 3,272,161 MCF (8,940 MCFPD) for the year ended December 31, 2012, a decline of 415,891 MCF (13%). Lower sale volumes resulted from production declines at Grand Isle 70, Vermilion 376, and High Island 115, as well as the sale of all the Company's interest in the lease on Ship Shoal. Production declines were partially offset by higher volumes at East Cameron 37, where the Company recompleted the #A-2 well in October, 2012; however, the well began producing water and was shut in on November, 2013.

In aggregate, crude oil, NGL and natural gas sales totaled 149,575 BOE (1,626 BOEPD) in Q4 2013 compared to 259,368 BOE (2,819 BOEPD) in Q4 2012, a decline of 109,793 BOE (42%). Sales volumes in 2013 comprised 36% crude oil, 4% NGLs, and 60% natural gas. For the year ended December 31, 2013, aggregate sales totaled 799,337 BOE (2,190 BOEPD) compared to 821,354 BOE (2,244 BOEPD) for the year ended December 31, 2012, a decline of 22,017 BOE (3%).

Realized Prices

Realized crude oil prices averaged $98.12 per barrel in Q4 2013 compared to $103.48 per barrel in Q4 2012, a decline of $5.36 per barrel (5%). For the year ended December 31, 2013, realized crude oil prices averaged $104.67 per barrel compared to $104.79 per barrel in the year ended December 31, 2012, a decline of $0.12 per barrel (0%). Most of the Company's crude pricing is derived from a combination of West Texas Intermediate ("WTI") crude prices and the Louisiana Light Sweet ("LLS") spread relative to WTI prices. Though WTI prices increased 4% in 2013, the LLS premium to WTI dropped from 14% to 9%.

Realized NGL prices averaged $33.62 per barrel in Q4 2013 compared to $30.12 per barrel in Q4 2012, an increase of $3.50 per barrel (12%). For the year ended December 31, 2013, realized NGL prices averaged $27.76 per barrel compared to $32.64 per barrel in the year ended December 31, 2012, a decline of $4.88 per barrel (15%). The drop in 2013 primarily reflects overall declines in U.S. NGL prices, as the Energy Information Administration's NGL composite index fell 9% last year. The decline in realized price received by the Company was further exacerbated due to deteriorating mix issues resulting in a higher ethane yield.

Realized natural gas prices averaged $3.48 per MCF in Q4 2013 compared to $3.48 per MCF in Q4 2012 (0%). For the year ended December 31, 2013, realized natural gas prices averaged $3.44 per MCF compared to $2.88 per MCF, an increase of $0.56 per MCF (19%). Higher realized prices in 2013 primarily reflect higher domestic natural gas prices (the average Henry Hub natural gas price increased 36% last year), partially offset by higher transportation and gathering charges at East Cameron 36/37 and High Island 201.

In aggregate, realized prices averaged $54.34 per BOE in Q4 2013 compared to $46.51 per BOE in Q4 2012, an increase of $7.83 per BOE (17%). For the year ended December 31, 2013, aggregate realized prices averaged $51.35 per barrel compared to $41.66 per barrel in the year ended December 31, 2012, an increase of $9.69 per barrel (23%). Higher aggregate prices are primarily the result of a shift in the Company's production mix to a higher percentage of liquids (crude and NGLs).

Revenues

Crude oil revenues totaled $6,207,383 in Q4 2013 compared to $8,096,185 in Q4 2012, a decline of $1,888,802 (23%). The year-over-year decline reflects a 19% drop in sale volumes and a 5% decline in the average realized price. For the year ended December 31, 2013, crude oil revenues totaled $30,292,705 compared to $22,886,206 for the year ended December 31, 2012, an increase of $7,406,499 (32%). The increase for the year ended December 31, 2013, primarily reflects a 33% increase in sale volumes.

NGL revenues totaled $309,030 in Q4 2013 compared to $590,160 in Q4 2012, a decline of $281,130 (48%). The year-over-year decline reflects a 53% drop in sales volumes, partially offset by a 12% increase in the average realized price. For the year ended December 31, 2013, NGL revenues totaled $940,406 compared to $1,879,687 for the year ended December 31, 2012, a decline of $939,281 (50%). The decline for the year ended December 31, 2013, reflects a 41% drop in sales volumes and a 15% decrease in the average realized price.

Natural gas revenues totaled $1,611,968 in Q4 2013 compared to $3,375,520 in Q4 2012, a decline of $1,763,552 (52%). The year-over-year decline reflects a 52% drop in sales volumes. For the year ended December 31, 2013, natural gas revenues totaled $9,815,289 compared to $9,436,445 for the year ended December 31, 2012, an increase of $378,844 (4%). The increase for the year ended December 31, 2013, reflects a 19% increase in the average realized price, partially offset by a 13% decline in sales volumes.

Total revenues totaled $8,128,381 in Q4 2013 compared to $12,061,865 in Q4 2012, a decline of $3,933,484 (33%). The year-over-year decline reflects a 42% drop in sales volumes, partially offset by a 17% increase in the average realized price. For the year ended December 31, 2013, total revenues totaled $41,048,401 compared to $34,221, 262 for the year ended December 31, 2012, an increase of $6,827,139 (20%). The increase for the year ended December 31, 2013, reflects a 23% increase in the average realized price, partially offset by a 3% decline in sales volumes. Revenues in 2013 were comprised of 74% crude oil, 2% NGLs, and 24% natural gas.

Expenses

Lease operating expenses totaled $2,934,138 in Q4 2013 compared to $3,497,410 in Q4 2012, a decline of $563,272 (16%). For the year ended December 31, 2013, lease operating expenses totaled $12,349,985 compared to $11,909,649 for the year ended December 31, 2012, an increase of $440,336 (4%). Higher lease operating expenses for the year ended December 31, 2013, primarily reflect increased costs at: 1) Vermilion 376, where the Company consolidated its working interest in March, 2012 and completed three new wells in June, 2012; and 2) East Cameron 36/37. The lower lease operating expenses recorded in Q4 2013 primarily reflect reduced costs at Eugene Island 28 and Grand Isle 70, as well as costs associated with the Company's non-producing properties. Lease operating expenses averaged $19.62 per BOE in Q4 2013 compared to $13.48 per BOE in Q4 2012, which represents a 45% increase in per unit operating expenses. For the year ended December 31, 2013, lease operating expenses averaged $15.45 per BOE compared to $14.50 per BOE for the year ended December 31, 2012, which represents a 7% increase in per unit operating expenses. The higher per unit expenses in 2013 primarily reflect the shift in the Company's production mix to a higher percentage of liquids, as oil fields generally require greater fixed operating costs than natural gas fields.

Depreciation and depletion expenses totaled $1,901,412 in Q4 2013 compared to $3,255,396 in Q4 2012, a decline of $1,353,984 (42%). For the year ended December 31, 2013, depreciation and depletion expenses totaled $8,708,209 compared to $8,417,986 for the year ended December 31, 2012, an increase of $290,223 (3%). Lower depreciation and depletion expenses in Q4 2013 reflect lower production volumes, while higher depreciation and depletion expenses for the year ended December 31, 2013, primarily reflect higher depletion rates at Vermilion 376. Depreciation and depletion expenses averaged $12.71 per BOE in Q4 2013 compared to $12.55 per BOE in Q4 2012, which represents a 1% increase in per unit expenses. For the year ended December 31, 2013, depreciation and depletion expenses averaged $10.89 per BOE compared to $10.25 per BOE for the year ended December 31, 2012, which represents a 6% increase in per unit operating expenses.

General and administrative expenses totaled $1,249,273 in Q4 2013 compared to $1,181,813 in Q4 2012, an increase of $67,460 (6%). For the year ended December 31, 2013, general and administrative expenses totaled $4,987,092 compared to $3,356,020 for the year ended December 31, 2012, an increase of $1,631,072 (49%). The increases primarily reflect higher director and employee compensation. General and administrative expenses averaged $8.35 per

BOE in Q4 2013 compared to $4.56 per BOE in Q4 2012, which represents an 83% increase in per unit expenses. For the year ended December 31, 2013, general and administrative expenses averaged $6.24 per BOE compared to $4.09 per BOE for the year ended December 31, 2012, which represents a 53% increase in per unit operating expenses.

Exploration and evaluation expenses totaled $321,368 in Q4 2013 and $2,483,731 for the year ended December 31, 2013. Exploration and evaluation expenses reflect drilling costs associated with the South Timbalier 198 #A-7ST1 well, which was deemed to be non-commercial in January, 2013.

Impairment expense (recovery) and asset retirement expense totaled $5,389,061 for the year ended December 31, 2013. The majority ($3,851,175) of the impairment relates to the write-down of reserves at Grand Isle 70.

Bad debt expenses totaled $88,613 in Q4 2013 and $2,885,059 for the year ended December 31, 2013. The majority of the bad debt expense relates to an allowance for the non-payment of capital and operating expenses by the owner WI interest in two wells at Vermilion 376 (see "Legal Proceedings").

Stock-based compensation expenses totaled $410,509 in Q4 2013 and $1,005,891 for the year ended December 31, 2013. These expenses relate to the amortization of costs associated with employee and director stock options granted in June, 2012, and September, 2013.

Finance expenses totaled $1,535,153 (cash expenses totaled $690,000) in Q4 2013 and $5,961,224 (cash expenses totaled $2,737,500) for the year ended December 31, 2013. Finance expenses were primarily comprised of: 1) interest charged on debt secured by certain assets of Probe Resources US Ltd.; 2) interest and accretion of debt discount associated with $22,500,000 of 12% Senior Secured Notes that were issued on October 22, 2012 (see "Liquidity"); and 3) accretion of the Company's liability for asset retirement obligations ("ARO").

Other gains (losses) totaled $518,000 in Q4 2013 and ($25,000) for the year ended December 31, 2013. Other items relate to unrealized gains or losses on financing warrants issued in conjunction with the 12% Senior Secured Notes (see "Liquidity"). The decline in the Company's publicly-traded stock price reduced the liability associated with the financing warrants, which required the Company to record an unrealized (non-cash) gain in Q4 2013.

Deferred tax recovery totaled $1,789,000 in Q4 2013 and $713,000 for the year ended December 31, 2013. Deferred taxes reflect 35% (corporate tax rate) of the Company's pretax income, excluding non-taxable deductions for debt accretion, stock-based compensation, and unrealized gains or losses on financing warrants. Deferred taxes for the year ended December 31, 2013, were partially offset by adjustments to prior period tax estimates.

Net Income

Net loss totaled $3,394,147 in Q4 2013 compared to a net loss of $5,792,837 in Q4 2012, an increase of $2,398,690. For the year ended December 31, 2013, net loss totaled $2,033,851 compared to a net loss of $3,687,669 for the year ended December 31, 2012, an increase of $1,653,818. Net income recorded in 2013 was weighed down by numerous non-cash charges, including impairment, depreciation and depletion, stock-based compensation, accrued interest, and debt and asset retirement obligation accretion.

Funds generated from operations (including dry hole costs) totaled $2,443,168 in Q4 2013, compared to $4,551,062 in Q4 2012, a decrease of $2,107,894 (46%) (see Non-IFRS Financial Measures below). For the year ended December 31, 2013, funds generated from operations including dry hole costs totaled $14,378,569, compared to $12,689,614 incurred in the year ended December 31, 2012, an increase of $1,688,955 (13%). The increase in funds generated from operations (including dry hole costs) for the year ended December 31, 2013, is primarily the result of higher production volumes from Vermilion 376, Grand Isle 70 and East Cameron 37, and well as lower dry hole expenses.

Other Non-IFRS Financial Measurements

Included in the MD&A are references to certain financial measures commonly used in the oil and natural gas industry, such as funds generated from operations including dry hole costs. These measures have no standardized meanings, are not defined by IFRS, and accordingly are referred to as non-IFRS measures. The determination of these measures may not be comparable to the same as reported by other companies and should not be considered an alternative to, or more meaningful than, cash provided by operating, investing and financing activities or net income as determined by IFRS.

The Company considers funds generated from operations including dry hole costs to be a key measure as it demonstrates the Company's ability to generate the cash necessary to repay debt and to fund future growth through capital investment. The company determines funds generated from operations including dry hole costs as cash provided by operating activities prior to changes in non-cash working capital items and decommissioning expenditures and including dry hole costs. A reconciliation of cash provided by operating activities to funds generated from operations is presented below.

	For the three months ended December 31,		For the twelve months ended December 31,	
	2013	2012	2013	2012
Cash provided (used) by operating activities	5,902,060	(1,813,607)	23,165,929	(3,649,216)
Change in non-cash working capital items	(3,309,988)	8,710,517	(7,245,243)	16,137,983
Cash abandonment costs	172,464	1,685,540	941,614	4,232,235
Dry hole costs	(321,368)	(4,031,388)	(2,483,731)	(4,031,388)
Funds generated from operations (including dry hole costs)	2,443,168	4,551,062	14,378,569	12,689,614

Seasonality

In general, the Company's business is not subject to seasonal factors and trends, although adverse weather conditions may result in temporary declines in production volumes and revenues and resulting decreases in profitability. In particular, operations in the Gulf of Mexico expose the Company to hurricane and tropical storm risks (which are insured by the Company) and, less often, cold weather risks that may result in declines in production associated with temporary cessations of production during such weather events and extended cessations of production associated with damage to facilities and/or pipelines arising from such risks. The Company did not incur any declines in production volumes and revenues or a resulting decrease in profitability as a result of any adverse weather conditions in Q4 2013.

Summary Quarterly Results

The following is a summary of selected quarterly information that has been derived from both the unaudited quarterly financial statements and the audited annual financial statements of the Company. This summary should be read in conjunction with the respective financial statements for the periods indicated.

	For the three months ended							
	Dec. 31, 2013	Sep. 30, 2013	Jun. 30, 2013	Mar. 31, 2013	Dec. 31, 2012	Sep. 30, 2012	Jun. 30, 2012	Mar. 31 2012
Revenues	$ 8,128,381	$ 10,630,237	$ 10,731,229	$ 11,558,554	$ 12,061,865	$ 12,997,594	$ 5,403,881	$ 3,757,922
Income (loss)	(3,394,147)	2,022,974	58,796	(721,474)	(5,792,837)	5,020,879	(619,091)	(2,296,620)
Net income (loss)	(3,394,147)	2,022,974	58,796	(721,474)	(5,792,837)	5,020,879	(619,091)	(2,296,620)
Net income (loss) per share - basic	(0.03)	0.02	-	(0.01)	(0.05)	0.05	(0.01)	(0.03)
Net income (loss) per share - diluted	(0.03)	0.02	-	(0.01)	(0.05)	0.05	(0.01)	(0.03)
OPERATIONS								
Sales								
Oil (Bbl)	63,260	75,096	76,498	74,565	78,242	82,984	30,903	26,279
NGL (Bbl)	9,193	5,990	8,816	9,876	19,592	29,581	6,483	1,930
Natural gas (Mcf)	462,735	695,145	752,227	946,163	969,198	1,175,480	811,970	315,513
Oil (BOE) [(1)]	149,575	196,944	210,685	242,135	259,368	308,478	172,714	80,795
Oil (BOE/day) [(1)]	1,626	2,141	2,315	2,690	2,819	3,353	1,898	888
Oil ($/Bbl)	$ 98.12	$ 108.99	$ 103.63	$ 106.93	$ 103.48	$ 103.94	$ 104.80	$ 111.33
NGL ($/Bbl)	33.62	19.01	26.00	29.20	30.12	30.09	47.14	48.56
Natural gas ($/Mcf)	3.48	3.35	3.42	3.48	3.48	2.96	2.28	2.31
Operating revenue								
Oil	$ 6,207,383	$ 8,184,498	$ 7,927,741	$ 7,973,082	$ 8,096,185	$ 8,625,723	$ 3,238,659	$ 2,925,639
NGL	309,030	113,880	229,173	288,325	590,160	890,182	305,607	93,738
Natural gas	1,611,968	2,331,859	2,574,315	3,297,147	3,375,520	3,478,439	1,852,868	729,617
Handling fees	-	-	-	-	-	3,250	6,747	8,927
Total	8,128,381	10,630,237	10,731,229	11,558,554	12,061,865	12,997,594	5,403,881	3,757,922
Expenses								
Lease operating expense	2,934,138	2,791,161	3,299,099	3,325,587	3,497,410	3,381,855	2,736,580	2,293,803
Lease operating expense per BOE [(1)]	19.62	14.17	15.66	13.73	13.48	10.96	15.84	28.39

(1) Gas volumes are converted to BOE on the basis of 6 Mcfe per 1 barrel.

Liquidity

As disclosed in prior periods, on October 22, 2012, the Company entered into a Note Purchase Agreement (the “NPA”) under which Rooster Oil & Gas, LLC, and Probe Resources US Ltd., as Co-Issuers, issued Senior Secured Notes due on October 22, 2014 in the aggregate principal amount of $22,500,000 (the “Notes”). The Notes are secured by a first priority security interest, lien and mortgage on all assets, including oil and gas leases and proceeds therefrom, owned by the Co-Issuers. The Notes bear interest at a rate equal to 12% per annum with interest payments due quarterly. The Company and its wholly owned subsidiary, Rooster Energy, L.L.C., are guarantors of the obligations of the Co-Issuers under the NPA and each has also granted a security interest in all of its property to secure the obligations of the Co-Issuers. No holder of the Notes is a related party to the Company nor is any holder a chartered bank, trust company or treasury bank. The proceeds from the sale of the Notes were used to repay certain obligations of the Company.

Effective October 11, 2013, the Company has entered into a First Amendment to the NPA. Pursuant to same, the Company and the Note holders agreed to covenant revisions that altered the approved plan of drilling by the Company. The Company also received approval to enter into a subordinated secured credit facility for borrowings up to CDN $8.0 million, as more specifically described below. The Company paid a consent fee of $450,000 to the Note holders and legal fees incurred by the Note holders.

On October 11, 2013, the Company entered into a subordinated secured credit facility with The K2 Principal Fund, L.P. and Chester F. Morrison, Jr., who are both significant shareholders of the Company (and Mr. Morrison is a director) that provides for borrowing up to CDN $8.0 million to be used for general corporate purposes. The initial advance under the credit facility was CDN $4.0 million (less a 2% original issue discount and administrative fees) resulting in proceeds to the Company of $3,234,466. The interest rate is nine percent (9%) per annum on all advances, and the credit facility matures 181 days following full satisfaction of the terms of the NPA, as amended. Additionally, it is secured only by certain oil and gas properties and proceeds therefrom owned by Probe Resources US Ltd. The net proceeds of the initial advance were used to pay certain accounts payable of the Company.

At December 31, 2013, the Company had a working capital deficiency of $46,858,516, including outstanding loans payable amounts which are due within the current year. In addition, a significant portion of the Company's accounts payable were past due, and the Company was not in compliance with required debt covenants under its senior secured notes at December 31, 2013.

Management has taken a number of steps subsequent to December 31, 2013 to address the Company's liquidity situation, including entering into two significant acquisition agreements which are anticipated to contribute significant additional positive cash flows and cost synergies. In addition, the Company obtained an additional second lien credit facility for $10 million, which has enabled the Company to reduce its accounts payable balances outstanding at December 31, 2013. The Company is also currently engaged in discussions for a new credit facility, and may pursue issuing additional equity following the anticipated closing of the acquisitions in May 2014.

Management believes that these transactions, combined with the Company's ongoing positive cash flows from operating activities and the continued support of its major shareholders, will be sufficient to fund its ongoing operations and fund its capital expenditures program over the upcoming year.

Asset Retirement Obligations

In addition to the amounts owed at December 31, 2013, the Company has an ongoing liability with respect to the plugging and abandonment of wells and decommissioning of facilities totaling $18,595,827 on a discounted basis. The timing and amount of settling such asset retirement obligations are based on management's best estimate at this time. In the event of unforeseen developments, the Company may be required to incur asset retirement costs sooner than otherwise anticipated and in amounts exceeding the asset retirement obligations recorded on the balance sheet.

Critical accounting estimates

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

Estimates and judgments are continually evaluated and are based on historical experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances. Accounting estimates will, by definition, seldom equal the actual results. Revisions to accounting estimates are recorded in the period in which the estimates are revised and in any future years affected.

The following discussion sets forth management's most critical estimates and assumptions in determining the value of assets, liabilities and equity:

Depletion and valuation of property and equipment

The amounts recorded for depletion and depreciation of components of property and equipment and the valuation of property and equipment are based on estimates. These estimates include proved and probable reserves, future production rates, future petroleum and natural gas prices, future development costs, remaining lives and periods of future benefits of the related assets and other relevant assumptions.

The Company's reserve estimates are evaluated annually pursuant to the parameters and guidelines stipulated under *National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities*. Changes in reserve estimates impact the financial results of the Company as reserves and estimated future development costs are used to calculate depletion and are also used in impairment calculations.

The discount rate used to calculate the net present value of cash flows for impairment testing is based on estimates of market conditions, recent asset sales and an approximate Company and industry peer group weighted average cost of capital. Changes in the general economic environment could result in significant changes to this estimate.

The determination of cash-generating units requires judgment in defining the smallest identifiable group of assets that generate cash inflows that are largely independent of the cash inflows from other assets or groups of assets. Cash-generating units are determined by similar geological structure, shared infrastructure, geographical proximity, commodity type, similar exposure to market risks and materiality.

Asset retirement obligations

The value of asset retirement obligations depends on estimates of current risk-free interest rates, future restoration and reclamation expenditures and the timing of those expenditures. Actual costs and cash outflows can differ from estimates because of changes in laws and regulations, public expectations, market conditions, discovery and analysis of site conditions and changes in technology.

Valuation of accounts receivable

The valuation of accounts receivable is based on management's best estimate of collectability and provision for doubtful accounts.

Stock options and warrants

The expected amounts recorded relating to the fair value of stock options and warrants granted are based on estimates of the expected future volatility of the Company's share price (based on historical and/or peer group volatility), market price of the Company's shares and risk-free interest rate at the grant date (based on government bonds), expected lives of the instruments (based on historical experience and general option holder behaviour), expected forfeiture rates (based on historical experience and general option holder behaviour), expected dividends and other relevant assumptions.

Income taxes

The amounts recorded for deferred income taxes are based on estimates as to the timing of the reversal of temporary differences and tax rates currently substantively enacted. They are also based on estimates of the probability of the Company utilizing certain tax pools and assets which, in turn, is dependent on estimates of proved and probable reserves, production rates, future petroleum and natural gas prices and changes in legislation, tax rates and interpretations by taxation authorities. The availability of tax pools is subject to audit and interpretation by taxation authorities.

Joint arrangements

The Company is party to various jointly controlled assets, processing, operating and other agreements in conjunction with its crude oil and natural gas processing activities. The revenues and expenses allocated between partners are governed by the terms of these agreements and are subject to interpretation and audit by the applicable parties.

Contractual Obligations

At December 31, 2013, principal contractual obligations requiring fixed payments consisted of the following:

	Payments Due By Period				
	Total	Less Than 1 Year	1 - 2 Years	2 - 5 Years	Over 5 Years
First Amended and Restated Term Note (1)	$ 6,000,000	$ 6,000,000	$ -	$ -	$ -
Term Promissary Note (1)	463,000	463,000	-	-	-
Senior Secured Notes (2)	22,500,000	22,500,000	-	-	-
Related Party Subordinate Note (3)	4,000,000	-	4,000,000	-	-
	$ 32,963,000	$ 28,963,000	$ 4,000,000	$ -	$ -

(1) Matures on April 2014. However, subject to an intercreditor subordination agreement payment is not required until October 22, 2014.

(2) Payable on October 22, 2014 with interest at 12% paid quarterly. The Company aslo has 9,000,000 warrants outstanding in connection with the Senior Secured Notes.

(3) CAN$4,000,000 payable 181 days after full satisfaction of the Senior Secured Notes with interest at 9% paid in arrears.

Additionally, the Company leases its corporate headquarters located at 16285 Park Ten Place, Suite 120, Houston, Texas 77084 pursuant to a lease agreement with a five (5) year term beginning July 1, 2012 through June 30, 2017. For the period beginning July 1, 2013 through June 30, 2014 the base rental rate is $16,720 per month.

Capital Expenditures

Capital expenditures totaled $10,072,146 in Q4 2013 and $36,361,558 for the year ended December 31, 2013. Capital expenditures in 2013 primarily reflect drilling expenditures related to the High Island A494 #B-4 well. The Company also recompleted the Eugene Island 28 #6 well in Q2 2013.

In addition, during 2013 the Company recorded a $2,483,731 charge for expenses related to the South Timbalier 198 #A-7 ST-1 development well. This well was deemed to be non-commercial in January, 2013. In 2012, the Company expensed $4,031,388 of charges incurred through year-end 2012 in connection with drilling the well. The charges incurred in 2013 relate to additional expenses incurred subsequent to year-end.

Off-Balance Sheet Arrangements

At December 31, 2013 the Company is not party to, and not currently party to, any off-balance sheet arrangements.

Financial Instruments and Other Instruments

As at December 31, 2013, the Company has one fixed price physical delivery contract pursuant to which it has agreed to sell certain quantities of natural gas and crude oil. Specifically, for the period November 1, 2013 through April 30, 2014, the Company is obligated to sell 350 barrels per day of crude oil at a fixed price of $98.49 per barrel less discounts.

At December 31, 2013, the Company did not have, and currently does not have, any derivative securities, financial or other instruments.

Transactions with Related Parties

During the year ended December 31, 2013, the Company had the following transactions and balances with related parties:

- Accounts payable and accrued liabilities to directors and/or entities associated with directors, totaled $165,500 at December 31, 2013. During the year ended December 31, 2013 the Company recorded additional purchases from Chet Morrison Contractors, LLC in the amount of $390,099. In addition, at December 31, 2013, the Company had accounts payable in the amount of $3,970,348 due and owing to Chet Morrison Contractors, LLC, which is indirectly owned and controlled by Chester F. Morrison, Jr., who is a director of the Company.

- The Company is indebted to The K2 Principal Fund L.P. in the total amount of $6,463,000 plus accrued interest of $1,326,897. Interest expense recorded during 2013 was $1,064,161. The debt is secured by certain assets of Probe Resources US Ltd. Paul Crilly is a director of the Company and a managing director of K2 & Associates Investment Management Inc., the general partner of The K2 Principal Fund L.P.

- In October, 2013, the Company entered into a subordinated secured credit facility which provides for borrowing up to CDN $8.0 million, with an initial advance of CDN $4.0 million (see "Liquidity"). At December 31, 2013, accrued interest related to the credit facility totaled $84,618 and the liability on the financial statements was $3,223,626. The K2 Principal Fund L.P. serves as "Administrative Agent" under the credit facility and it is also a participating lender in the credit facility along with Chester F. Morrison, Jr. The K2 Principal Fund, L.P. and Mr. Morrison are related parties to the Company and neither is a chartered bank, trust company or treasury bank.

- Cochon Properties, LLC, and Cretaceous, LLC, participated in the drilling and completion of the High Island A494 #B-4 well with 6.25% WI and 1.25% WI, respectively. Cochon Properties, LLC, is owned ninety percent (90%) and controlled by Chester F. Morrison, Jr., who is a director of the Company. Cretaceous, LLC, is owned by Robert P. Murphy, who is President, Chief Executive Officer and a Director of the Company. The terms and conditions of their participation in the well is the same as that negotiated by the Company with the other two, non-related parties participating in the well. Accounts receivable related to this transaction was $265,547 at December 31, 2013.

In March 2014, the Company entered into a secured credit facility with Chester F. Morrison, Jr., who is a related party, which provides for borrowing up to $10 million, with an initial advance of $4.4 million (see "Other Subsequent Events").

Outstanding Share Data

The Company is authorized to issue an unlimited number of common shares (that may be converted to proportionate voting shares) and an unlimited number of preferred shares issuable in series with no par value. As of the date hereof, there were 65,071 proportionate voting shares (each convertible to 1,000 common shares) and 40,397,323 common shares issued and outstanding or the issued share capital on a fully diluted basis was the equivalent of 105,468,323 common shares. No preferred shares are issued or outstanding.

In association with the NPA, as amended (see "Liquidity"), the Company entered into a Warrant Purchase Agreement with a five-year term with the holders of the Notes pursuant to which it has agreed to sell warrants for up to 9,000,000 common shares of the Company at an exercise price of CDN $1.00 per common share.

Pursuant to the stock option plan approved by shareholders on April 20, 2012, on June 5, 2012, the Company approved the grant of incentive stock options to directors, officers and employees for acceptance in the total amount of 4,820,645. The exercise price is CDN $0.50 per option and expiry date is June 5, 2022. As of December 31, 2013 there have been 6,666 options exercised and 53,334 options forfeited.

On July 16, 2013, the shareholders of the Company voted to amend and restate the stock option plan and approved the Rooster Energy Ltd. 2013 Stock Incentive Plan. On September 11, 2013, the Company awarded stock options to directors, senior officers and employees for acceptance in the total amount of 4,532,759 common shares. The exercise price is CDN $0.82 per option and expiry date is September 11, 2023. Subsequent to the foregoing award, the number of common shares available for future award under the Rooster Energy Ltd. 2013 Stock Incentive Plan is 12,043,106.

Other than those issued under Warrant Purchase Agreement or the Rooster Energy Ltd. 2013 Stock Incentive Plan (and the proportionate voting shares (each of which is convertible into 1,000 common shares), there were no warrants, stock options or other securities convertible into common shares outstanding on December 31, 2013.

Legal Proceedings

The Company is a party to several legal proceedings which are incidental to the ordinary course of business. We regularly analyze current information and, as necessary, provide accruals for probable liabilities on the eventual disposition of these matters. In the opinion of management, as of the date of the filing of this MD&A, there are only two threatened or pending legal matters that could have a material impact on our consolidated results of operations, financial position or cash flows.

376 OG Holdings, LLC, vs. Texas OG Acquisitions, LLC, CA No. 6:12CV2534, USDC, W.D. La. (Lafayette Div)

On February 5, 2013, Rooster Petroleum, LLC, intervened in the above noted action to assert an operators oil and gas lien or privilege in the amount of $2,264,701 for unpaid drilling and completion costs against the working interest allegedly owned by Texas OG Holdings, LLC, in the Rooster Vermilion 376 #A-3 & #A-4 Wells (for purposes of this section only, the "**Wells**") which was pending foreclosure by 376 OG Holdings, LLC, and sale by the U.S. Marshall. Rooster Petroleum, LLC asserted that its lien on the Wells for moneys owed to it by Implicit Oil & Gas (VR 376), LLC ("**Implicit**"), the alleged successor to Texas OG Holdings, was superior in rank to the mortgage at issue. The foreclosure order was subsequently withdrawn.

On September 30, 2013, Rooster Petroleum, LLC, and Rooster Oil & Gas, LLC (for purposes of this section only, together "**the Rooster Interveners**") filed a first amended complaint in intervention against the defendants (and added additional related parties including Implicit and its owner, Ron Beneke, individually) an alleged 20 causes of action seeking primarily rescission of the sale of the working interest to Implicit, declaratory relief and money damages all related to the drilling, completion and operation of the Wells and the attempted sale to enforce the mortgage on the working interest. At the date of this MD&A, there has not been any counterclaim asserted against the Rooster Interveners.

In connection with this case, in July 2013, the Rooster Interveners agreed to deposit 18.1665% (approximately the net revenue interest attributable to the Implicit working interest in dispute) of the proceeds that it receives from the sale of oil and gas production from the Wells after June 18, 2013 into an escrow account with JPMorgan Chase Bank, NA. The funds in the escrow account can only be released upon consent of all parties to the escrow agreement or by order of the court in this matter. The Rooster Interveners claim they are entitled to all of the funds held in the escrow account which amount to the approximate sum of $3,184,129 as at the date of this MD&A.

Rooster Oil & Gas, LLC, & Rooster Petroleum, LLC vs. Birnham Energy Investment Company, L.P. (f/k/a Implicit Oil & Gas, L.P.) & Implicit Oil & Gas (VR 375), LLC, Cause No. 2013-17984, 165th JDC, Harris County, Texas.

On March 27, 2013, Rooster Petroleum, LLC, and Rooster Oil & Gas, LLC (for the purposes of this section only, together, the "**Rooster Plaintiffs**") filed suit to collect outstanding accounts receivable related to the drilling, completion and operation of the Rooster Vermilion 376 #A-3 & #A-4 Wells (for the purposes of this section only, the "**Wells**"). On November 21, 2013, Birnham *et al* filed a first amended counterclaim (and added Rooster Energy, L.L.C., and Rooster Energy Ltd. (for purposes of this section only, together with the Rooster Plaintiffs, the "**Rooster Entities**") as defendants in counterclaim). In the counterclaim, Birnham *et al* have alleged seven causes of action. Five of the causes of action seek money damages and indemnity against the Rooster Entities for various amounts resulting primarily from breach of contract and the subsequent failure or refusal of the Rooster Entities to pay Birnham *et al* for its alleged share of production from the Wells. The remaining two causes of action seek appointment of an auditor of the account for the Wells and the appointment of a receiver for each of the Rooster Entities. The Rooster Entities consented to the appointment of the auditor who is currently auditing the joint interest account for the Wells. As of the date of this Circular, Birnham *et al* has not made a motion for appointment of a receiver. Rooster's management believes that Rooster has valid defenses to all of the counterclaims and is defending against such counterclaims.

Birnham *et al* is seeking punitive damages in connection with its claims. However, since all claims are concerning or related to the Wells on federal leases offshore of the state of Louisiana, Louisiana law will apply. Under Louisiana law, punitive damages are only available in limited instances and none of those have been asserted by Birnham *et al*. Accordingly, Rooster's management believes that in the unlikely event that Birnham *et al* were to obtain judgment in their favor, it would not have a material adverse effect on the Company.

Other Subsequent Events

Effective March 7, 2014, the Company entered into an additional secured credit facility (the "Second Credit Facility") which provides for borrowing up to US $10 million, to be used for general corporate purposes. The initial advance under the Second Credit Facility is US $4.4 million, net of an original issue discount of 10% for a funded amount equal to US $4 million. The Second Credit Facility is fully subordinated to the Notes pursuant to the terms of a subordination and intercreditor agreement.

The interest rate is fourteen (14%) per annum on all advances under the Second Credit Facility and the maturity date is 181 days after the full satisfaction of the terms of the Notes. The Second Credit Facility is secured by all oil and gas properties and assets owned by Rooster Oil & Gas, LLC, a wholly owned subsidiary of the Company, and the Company is the guarantor of any indebtedness owed under the Second Credit Facility.

Chester F. Morrison, Jr., serves as second lien "Administrative Agent" for the lender(s) under the Second Credit Facility. Mr. Morrison is also the sole lender in the Second Credit Facility. Mr. Morrison is a related party since he directly and indirectly holds approximately 62% of the issued and outstanding common shares and proportionate voting shares of the Company and serves as a director of the Company.

In order to enter into the Second Credit Facility, the Company obtained the consent of the holders of the Notes pursuant to a second amendment to Note Purchase Agreement dated March 7, 2014 (the "Second Amendment"). The Second Amendment material terms include that (a) the holders of the Notes waive any provisions under the Notes that would prohibit, impair or restrict the ability of the Company to consummate the loan under the Second Credit Facility; (b) that the Company restrict any payments under the Second Credit Facility as provided for in a subordination agreement; and (c) that in addition to all amounts repaid under the terms of the Notes, the Company shall pay an additional payment in an amount equal to three percent (3%) of the principal amount repaid.

Also effective March 7, 2014, the Company entered into membership interest contribution agreements whereby the Company will acquire all of the membership interests of Morrison Well Services, LLC, ("Well Services") and Cochon Properties, LLC, ("Cochon") for aggregate consideration of $125 million, with $95 million and $30 million relating to the acquisitions of Well Services and Cochon, respectively, subject to working capital adjustments as outlined in the membership interest contribution agreements. Of the total consideration, $10 million (plus or minus any working capital adjustments) is payable by the Company in cash (or assumed indebtedness of Well Services), with the remaining amount payable by way of common shares of the Company (or proportionate voting shares of the Company, if so elected by any of the members of Cochon or the sole member of Wells Services). The number of common shares to be issued will equal that number obtained by dividing $115 million by the average daily closing price of the Rooster common shares for the 20 consecutive trading days on which shares are actually traded and quoted on the TSX Venture Exchange ending on and including the date that is 10 business days prior to the special shareholder meeting to approve the transactions, subject to a minimum price of CDN $0.40 and a maximum price of CDN $0.70. Pursuant to the transactions, Well Services and Cochon will each become a wholly-owned subsidiary of the Company. Well Services and Cochon are owned, in whole or in significant part, and controlled by Chester F. Morrison, Jr., a related party who is an approximate 62% shareholder and director of the Company. Closing of the transactions are expected to occur in the second quarter of fiscal 2014, subject to, among other conditions, receipt of required regulatory and shareholder approvals.

Chester F. Morrison, Jr., the majority shareholder of the Company and a director, owns 90% of the membership interest in Cochon and wholly owns and controls, indirectly, Wells Services. Accordingly, the acquisition constitutes a related party transaction for the purposes of Multilateral Instrument 61-101 – *Protection of Minority Security Holders in Special Transactions* ("MI 61-101") and must receive minority approval (as such term is defined in MI 61-101) of the shareholders of the Company. The majority required to pass the resolution approving the acquisition will be not less than 50% of the votes cast by the shareholders represented in person or by proxy at the special meeting of shareholders to be held on May 16, 2014, excluding votes attributable to those shares of the Company owned or controlled, directly or indirectly, by Mr. Morrison. The K2 Principal Fund, L.P. ("K2"), owner of approximately 51.29% of the issued and outstanding common shares of the Company and approximately 19.65% of the equity in voting interests in the Company, has entered into a support agreement to vote all of its shares in favor of the acquisition. The common shares held by K2 represent more than 51% of the votes attached to the minority of Company shares entitled to vote on the acquisition.

As a result of the acquisition, the percentage of common shares, on a fully diluted basis, owned or controlled, directly or indirectly, by Mr. Morrison is expected to increase from 62% to approximately 85% to 90%.

Well Services is a special purpose entity organized to acquire the assets of the well services division of Chet Morrison Contractors, LLC and thereafter conduct a well services business that will generate revenues and cash flows primarily by performing down-hole and subsea oil and gas well plug and abandonment services. The services provided are marketed to almost all operators of oil and gas wells located in the U.S. Gulf of Mexico.

Cochon owns twelve (12) oil and gas leases containing approximately 15,985 gross acres covering Eugene Island 18, Vermilion 67, and West Delta 44/45; for the three months ended September 30, 2013, the fields produced 77,561 BOE, or 843 BOE per day (16% liquids). At October 31, 2013, Cochon's proved and probable reserves totaled 4,361,242 BOE (62% proved, 29% liquids) with a NPV-10% of $61,186,593.

In order to enter into the membership interest contribution agreements for Well Services and Cochon, the Company obtained the consent of the holders of the Notes pursuant to a limited consent and forbearance agreement dated March 7, 2014 (the "Limited Consent"). Therein, the holders of the Notes and the Company acknowledged that at the end of fourth quarter of 2013, the Company was in existing and continuing default of the collateral coverage ratio covenant of the Notes (the "Specified Default") and in order to allow for the acquisition of Cochon and Well Services, the Limited Consent provides that, the holders of the Notes will forbear from exercising certain rights and remedies under the Note Purchase Agreement and certain related documents in respect of the Specified Default until the date which is the earliest to occur of the date *inter alia* (a) that any representation or warranty made by any holder of the Notes in the Limited Consent is false; (b) that certain voluntary or involuntary insolvency proceedings in relation to a holder of the Notes is commenced; (c) of the occurrence after the effective date of the forbearance obligations in the Limited Consent of an event of default other than the Specified Default; (d) that any litigation is commenced by a holder of the Notes in relation to the Note Purchase Agreement or the Limited Consent or other documents related thereto; (e) of the exercise by any creditor or holder of indebtedness of the Company of any rights available to them in connection with the indebtedness including but not limited to foreclosure or enforcement against any collateral of the Company; (f) of the payment in full of the obligations under the Note Purchase Agreement; (g) March 21, 2014 unless the Company received a fairness opinion in respect of the acquisition of Cochon and Well Services prior to such date and; (h) July 7, 2014.

On March 14, 2014, Cowen and Company, LLC, issued an opinion to the Company opining that subject to certain assumptions and limitations, the purchase price to be paid for Cochon and Well Services is fair from a financial point of view to the Company.

On April 16, 2014, the Company filed Amended Condensed Interim Consolidated Financial Statements of the Company for the Three and Nine Months Ended September 30, 2013 and 2012 and corresponding Amended Management's Discussion and Analysis (the "Q3 Filings"). The Q3 filings have been amended to include disclosure of certain events subsequent to September 30, 2013, including that in connection with the proposed acquisition by the Company of Well Services and Cochon, the Company and the holders of the Notes acknowledged that the Company was in default of the collateral coverage ratio under the senior secured notes and the Notes holders agreed to forbear from exercising certain rights and remedies. The previously filed information in respect of such September 30, 2013 filings is unchanged other than the addition of the subsequent event disclosure.

The Company's deficiency in satisfying the collateral coverage ratio was primarily the result of over expenditures in the second and third quarters of 2013 related to the drilling and completion of the High Island A-494 #B-4 well. The Company intends to move forward with a plan to develop the potential oil and gas reserves identified in the well and is engaged in discussions for a new credit facility that will allow the Company to resolve its working capital deficit, satisfy its obligations to the Note holders and continue the Company's growth to maximize shareholder value. The Company will also continue to examine other corporate strategies, including asset divestitures and additional debt or equity financings, in order to finance its ongoing capital expenditure program and settle its long-term liabilities as they fall due.

On April 16, 2014, the Company also filed and mailed to shareholders a Management Information Circular disclosing information related to the Company's proposed acquisition of Cochon and Well Services.

Forward Looking Information and Statements

This MD&A may contain forward looking information related to planned drilling program, production, revenue, commodity prices, royalties, capital expenditures and commitments, operating costs, general and administrative expenses, funds flow from operations, financing plans, liquidity and capital resources and debt settlement. Forward-looking information is based on expectations and estimates as of the date of this document, and is information that is subject to known and unknown risks and other factors that may cause future actions, conditions or events to differ materially from the anticipated actions, conditions or events expressed or implied by such forward-looking information. Forward-looking information is information that does not relate strictly to historical or current facts, and can be identified by the use of the future tense or other forward-looking words such as "believe", "expect", "anticipate", "intend", "plan", "estimate", "should", "could" "may", "objective", "projection", "forecast", "continue", "strategy", "position" or the negative of those terms or other variations of them or comparable terminology.

Further examples of such forward-looking information in this document include but are not limited to the following, each of which is subject to significant risks and uncertainties and is based on a number of assumptions, which may prove to be incorrect including: the amounts recorded for depletion, depreciation and accretion, the provision for asset retirement obligations and the ceiling test, which are based on estimates of reserves, production rates, petroleum and natural gas prices, future costs and other relevant assumptions. Stock-based compensation expense is based upon estimates using the Black-Scholes option pricing model.

Risks include, but are not limited to, the availability and costs of financing, general economic conditions, storm weather risks, and risks associated with the oil and gas industry (e.g., operational risks in development, exploration and production; delays or changes in plans with respect to exploration or development projects or capital expenditures; the financial health of joint venture partners; health, safety and environmental risks; and the uncertainty of dealing with government and obtaining regulatory approvals).

At this time, the most significant risk relates to the uncertainty of the Company's ability to finance development plans and ongoing operations, the results of any such development operations and future oil and gas prices and the current volatility in these markets. Revenues and funds flow from operations will be impacted positively or negatively depending on the ultimate variance to our forecast assumptions. Furthermore, the outcome of commodity price changes are expected to impact our capital spending plans and the ability of joint venture partners and other sources of capital funding to provide financing for projects.

Operations may be unsuccessful or delayed as a result of competition for services, supplies and equipment, mechanical and technical difficulties, ability to attract and retain employees on a cost effective basis, commodity and marketing risk and seasonality. The company is subject to significant drilling risk and uncertainties including the ability to find oil and gas reserves on an economic basis, and is also exposed to risks relating to the inability to obtain timely regulatory approvals, surface access, access to third party gathering and processing facilities, transportation and other third party related operational risks.

Financial risks that the Company is exposed to include, but are not limited to, access to debt or equity markets and fluctuations in commodity prices, interest rates and the Canadian/US dollar exchange rate.

It is anticipated that subsequent events and developments may cause a change to the assumptions made by us. The Company does not have an intention to update this forward-looking information, except as required by applicable securities laws. This forward-looking information represents the Company's views as of the date of this document and such information should not be relied upon as representing its views as of any date subsequent to the date of this document. Highlighted here are important factors that could cause actual results, performance or achievements to vary from those current expectations or estimates expressed or implied by the forward-looking information. However, there may be other factors that cause results, performance or achievements not to be as expected or estimated and that could cause actual results, performance or achievements to differ materially from current expectations.

There can be no assurance that forward-looking information will prove to be accurate, as actual results and future events could differ materially from those expected or estimated in such statements. Accordingly, readers should not place undue reliance on forward-looking information. These factors are not intended to represent a complete list of factors that could affect the Company.

Date

This MD&A is dated April 25, 2014.

Additional Information

Additional information regarding the Company is available at SEDAR www.sedar.com and at www.roosterenergyltd.com

APPENDIX A

	For the three months ended December 31,		For the twelve months ended December 31,	
	2013	2012	2013	2012
EBITDAX [(a)] Calculation:				
Income (loss)	(3,394,147)	(5,792,837)	(2,033,851)	(3,687,669)
DD&A	1,901,412	3,255,396	8,708,209	8,417,986
Exploration and evaluation	321,368	4,037,856	2,483,731	3,734,313
Non-cash plug and abandonment	0	0	0	940,000
Bad debt expense	88,613	302,337	2,885,059	302,337
Stock-based compensation	410,509	217,413	1,005,891	507,298
Finance expenses and unrealized loss on financing warrants	1,017,153	14,847	5,986,224	848,534
Impairment expense	4,802,756	(425,866)	4,802,756	(82,080)
Asset retirement expense	586,305	452,351	586,305	452,351
Deferred tax expense (recovery)	(1,789,000)	5,288,000	(713,000)	5,288,000
EBITDAX	3,944,969	7,349,497	23,711,324	16,721,070

(a) EBITDAX is a non-IFRS measure commonly used in the oil and gas industry. Such measures do not conform to IFRS and may not be comparable to those reported by other companies nor should they be viewed as an alternative to other measures of financial performance calculated in accordance with IFRS. The company defines EBITDAX as net income before finance expense, taxes, depreciation, amortization, accretion, exploration and evaluation, bad debt, impairments, stock-based compensation, and the non-cash portion of plug and abandonment expense.