ROOSTER ENERGY LTD.

Management Discussion and Analysis (Amended and Restated)
September 30, 2013

This amended and restated management discussion and analysis ("MD&A") of Rooster Energy Ltd. ("Rooster" or, the "Company") reflects its September 30, 2013 financial results and operations as well as updated subsequent event disclosures and developments following September 30, 2013 through March 31, 2014 which amends and restates in its entirety the MD&A previously filed by the Company on SEDAR. This MD&A should be read in conjunction with the Company's amended unaudited condensed consolidated interim financial statements and related notes as at and for the three and nine months ended September 30, 2013 which contain updated subsequent events disclosures from the condensed interim consolidated financial statements previously filed by the Company on SEDAR, which were prepared in accordance with International Accounting Standards 34, Interim Financial Reporting, as issued by the International Accounting Standards Board ("IASB") and with the Company's audited consolidated financial statements and related notes at and for the year ended December 31, 2012. All dollar amounts are stated in U.S. dollars, unless otherwise noted.

Restatement

The MD&A has been amended and restated to include disclosure of certain events subsequent to September 30, 2013, including that in connection with the proposed acquisition by the Company of Morrison Well Services, LLC ("Well Services) and Cochon Properties, LLC ("Cochon"), the Company and the holders of its outstanding $22,500,000 of 12% senior secured notes ("Notes") that were issued on October 22, 2012 acknowledged that the Company was in default of the collateral coverage ratio under the Notes and the holders of the Notes agreed to forbear from exercising certain rights and remedies. The previously filed information in respect of the MD&A is unchanged other than the addition of the subsequent event disclosure.

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 September 30, 2013, our primary assets consist of operating rights interests and/or record title interests in 20 producing oil and/or natural gas wells, 16 of which are operated, and 16 leases or blocks granted by the United States of America.

Our core business and strategy is focused on the development of our inventory of oil and natural gas properties and the production and sale of oil and natural gas from those properties. We have identified drilling locations to which we 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 are: (i) ability to successfully discover, develop, and exploit commercial oil and natural gas reserves on our properties; and (ii) ability to optimize profitability from operation of producing wells. Further, our ability to successfully discover, develop, and exploit properties is a function of, among other things: (i) ability, or the ability of our partners, to retain drilling rigs, drillers, personnel and supplies to carry out drilling operations in a professional and cost effective manner; (ii) the ultimate results of such drilling operations; (iii) the availability, on commercially reasonable terms, of transportation, storage, handling, processing and other facilities to service producing wells; and (iv) ability to finance the costs of such operations. Our ability to optimize profitability from the operation of producing wells 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. 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 Q3 2013

The Company produced 196,943 barrels of oil equivalent ("BOE") in Q3 2013 (third quarter, or three months ended September 30, 2013), compared to 308,478 BOE produced in Q3 2012, a 36% decline year-over-year. The lower sale 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 Q3 2013, the Company generated EBITDAX of $6,595,206, which was lower than the $8,606,639 generated in Q3 2012. Lower production volumes were partially offset by higher realized prices and lower operating expenses (for calculation, see Appendix A).

The Company recorded net income of $2,022,974 in Q3 2013, which was impacted by several non-cash items including $1,161,000 of deferred tax expense that was partially offset by a $921,000 unrealized gain on financing warrants. Funds generated from operations (including dry hole costs) totaled $5,138,203 in Q3 2013, compared to $8,213,653 in Q3 2012, a decrease of $3,075,450 (see Non-IFRS Financial measurements on page 9). In addition to lower sale volumes, higher finance expenses contributed to the year-over-year decline in funds generated from operations.

Business

At September 30, 2013, the Company's interests in oil and natural gas leases consisted of ownership in 16 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 Q3 2013, the Company's net crude oil sales averaged 816 barrels per day (BOPD), net natural gas liquids (NGLs) sales averaged 65 barrels of oil equivalent per day (BOEPD), and net natural gas sales averaged 7,556 thousand cubic feet per day (MCFPD) (or 1,259 BOEPD); in aggregate, total crude oil, NGL, and natural gas sales averaged 2,141 BOEPD. The Company's four primary operated properties, Vermilion 376, Eugene Island 28, Grand Island 70, East Cameron 36/37, comprised 94% of Q3 2013 sale volumes.

On March 20, 2013, the Company submitted high bids on two lease blocks – East Cameron 39 and Vermilion 20 – at the Central Gulf of Mexico Federal Lease Sale 227, both of which have been awarded by the Department of Interior; lease bonuses totaled approximately $250,000. The lease on Vermilion 20 was effective May 1, 2013 and the lease on East Cameron 39 was effective July 1, 2013. As a result, the Company now has an inventory of four (4) 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 most recently completed financial years, reflecting the results of operations of the Company for the years ended December 31, 2012, 2011, and 2010:

Financial	For the years ended December 31,		
	2012	2011	2010
Total revenues	$ 34,221,262	$ 21,001,250	$ 22,007,909
Operating income (loss)	2,448,865	4,477,521	326,224
Unrealized gain on financing warrants	1,317,000	-	-
Net interest expense and financing costs	(2,165,534)	(952,237)	(509,468)
Deferred income tax expense	(5,288,000)	-	-
Net income (loss)	(3,687,669)	3,525,284	(183,244)
Income (loss) per share - basic	(0.04)	0.04	0.00
Income (loss) per share - diluted	(0.04)	0.04	0.00
Total assets	96,577,261	39,965,322	34,699,496
Total long-term financial liabilities	54,331,401	13,008,253	13,753,440
Cash dividends per share	-	-	-

Results of Operations

The following table summarizes production volumes, average sales prices and operating revenues for the three and nine months ended September 30, 2013 and 2012:

	For the three months ended September 30, 2013	For the three months ended September 30, 2012	For the nine months ended September 30, 2013	For the nine months ended September 30, 2012
Sales				
Oil (Bbl)	75,096	82,984	226,159	140,166
NGL (Bbl)	5,990	29,581	24,681	37,994
Natural gas (Mcf)	695,145	1,175,480	2,393,535	2,302,964
Oil (BOE) [a]	196,943	308,478	649,762	561,987
Oil (BOE/day) [a]	2,141	3,353	2,380	2,051
Oil ($/Bbl)	$ 108.99	$ 103.94	$ 106.50	$ 105.52
NGL ($/Bbl)	19.01	30.09	25.58	33.94
Natural gas ($/Mcf)	3.35	2.96	3.43	2.63
Summary statement of income				
Revenue	$ 10,630,237	$ 12,997,594	$ 32,920,020	$ 22,159,397
Expenses				
Lease operating costs	2,791,161	3,381,855	9,415,848	8,412,238
Depreciation and depletion	2,142,053	2,579,192	6,806,797	5,162,590
Exploration and evaluation	3,205	-	2,162,364	(303,543)
Plug and abandonment [b]	-	-	-	2,362,072
General and administrative	1,243,870	1,009,100	3,737,816	2,174,207
Transaction costs	-	-	-	779,306
Bad debt expense	125,584	-	2,796,446	-
Impairment expense	-	343,786	-	343,786
Stock-based compensation	200,085	190,755	595,382	289,885
Total costs and expenses	6,505,958	7,504,688	25,514,653	19,220,541
Operating income (loss)	4,124,279	5,492,906	7,405,367	2,938,856
Unrealized loss on financing warrants	921,000	-	(543,000)	-
Finance expenses [c]	(1,861,305)	(472,027)	(4,426,071)	(833,687)
Income (loss) before tax expense	3,183,974	5,020,879	2,436,296	2,105,169
Deferred tax expense (recovery)	1,161,000	-	1,076,000	-
Income (loss)	2,022,974	5,020,879	1,360,296	2,105,169
Income (loss) per share				
Basic	0.02	0.05	0.01	0.02
Diluted	0.02	0.05	0.01	0.02
Weighted average shares outstanding [d]				
Basic	105,467,997	105,465,823	105,465,898	99,201,899
Diluted	106,661,600	107,029,275	105,465,898	100,595,034
Capital expenditures	$ 16,369,381	$ 676,390	$ 26,289,412	$ 26,742,395
EBITDAX [e]	$ 6,595,206	$ 8,606,639	$ 19,766,356	$ 9,371,574

(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, amortization, accretion, exploration and evaluation, bad debt, impairments, stock-based compensation, and the non-cash portion of plug and abandonment expense.

Sale Volumes

Crude oil sales totaled 75,096 barrels (816 BOPD) in Q3 2013 compared to 82,984 barrels (902 BOPD) in Q3 2012, a decline of 7,888 barrels (-10%). For the nine months ended September 30, 2013, crude oil sales totaled 226,159 barrels (828 BOPD) compared to 140,166 barrels (512 BOPD) for the nine months ended September 30, 2012, an increase of 85,993 barrels (+61%). The Company completed a three-well drilling program at Vermilion 376 in June, 2012, which enabled higher production volumes for the nine months ended September 30, 2013. However, with no new wells brought online since, natural production declines – particularly at Vermilion 376 and Eugene Island 28 – led to a year-over-year decline in sale volumes in Q3 2013.

Natural gas liquid (NGL) sales totaled 5,990 BOE (65 BOEPD) in Q3 2013 compared to 29,581 BOE (322 BOEPD) in Q3 2012, a decline of 23,591 BOE (-80%). For the nine months ended September 30, 2013, NGL sales totaled 24,681 BOE (90 BOEPD) compared to 37,994 BOE (139 BOEPD) for the nine months ended September 30, 2012, a decline of 13,313 BOE (-35%). 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. Production at Grand Isle 70 was further hampered as modifications made to a processing facility required the field to be shut in for 19 days in August, 2013. 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 (95% of its production was crude oil in Q3 2013), which led to lower gas sales from year-ago levels.

Natural gas sales totaled 695,145 thousand cubic feet (MCF) (7,556 MCFPD) in Q3 2013 compared to 1,175,480 MCF (12,777 MCFPD) in Q3 2012, a decline of 480,335 MCF (-41%). For the nine months ended September 30, 2013, natural gas sales totaled 2,393,535 MCF (8,768 MCFPD) compared to 2,302,964 MCF (8,405 MCFPD) for the nine months ended September 30, 2012, an increase of 90,571 MCF (+4%). Rooster recompleted the East Cameron 37 #A-2 well in October, 2012, which enabled higher production volumes for the nine months ended September 30, 2013. However, production declines – particularly at Grand Isle 70 and Vermilion 376 (as previously described) – led to a year-over-year decline in sale volumes in Q3 2013.

In aggregate, crude oil, NGL, and natural gas sales totaled 196,943 BOE (2,141 BOEPD) in Q3 2013 compared to 308,478 BOE (3,353 BOEPD) in Q3 2012, a decline of 111,535 BOE (-36%). Q3 2013 sale volumes were comprised of 38% crude oil, 3% NGLs, and 59% natural gas. For the nine months ended September 30, 2013, aggregate sales totaled 649,762 BOE (2,380 BOEPD) compared to 561,987 BOE (2,051 BOEPD) for the nine months ended September 30, 2012, an increase of 87,775 BOE (+16%).

Realized Prices

Realized crude oil prices averaged $108.99 per barrel in Q3 2013 compared to $103.94 per barrel in Q3 2012, an increase of $5.05 per barrel (+5%). For the nine months ended September 30, 2013, realized crude oil prices averaged $106.50 per barrel compared to $105.52 per barrel in the nine months ended September 30, 2012, an increase of $0.98 per barrel (+1%). 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 15% year-over-year in Q3 2013, this was partially offset by diminishing LLS spreads.

Realized NGL prices averaged $19.01 per barrel in Q3 2013 compared to $30.09 per barrel in Q3 2012, a decline of $11.08 per barrel (-37%). For the nine months ended September 30, 2013, realized NGL prices averaged $25.58 per barrel compared to $33.94 per barrel in the nine months ended September 30, 2012, a decline of $8.36 per barrel (-25%). The declines primarily reflect overall declines in U.S. NGL prices, as well as deteriorating mix issues resulting in a higher ethane yield.

Realized natural gas prices averaged $3.35 per MCF in Q3 2013 compared to $2.96 per MCF in Q3 2012, an increase of $0.39 per MCF (+13%). For the nine months ended September 30, 2013, realized natural gas prices averaged $3.43 per MCF compared to $2.63 per MCF, an increase of $0.80 per MCF (+30%). Higher realized prices primarily reflect overall increases in U.S. natural gas prices (the average Henry Hub natural gas price increased 23% year-over-year in Q3 2013), partially offset by higher transportation and gathering charges at East Cameron 36/37 and High Island 201.

In aggregate, realized prices averaged $53.98 per BOE in Q3 2013 compared to $42.13 per BOE in Q3 2012, an increase of $11.85 per BOE (+28%). For the nine months ended September 30, 2013, aggregate realized prices averaged $50.66 per barrel compared to $39.43 per barrel in the nine months ended September 30, 2012, an increase of $11.23 per barrel (+28%). Higher crude oil and natural gas prices were partially offset by lower NGL prices.

Revenues

Crude oil revenues totaled $8,184,498 in Q3 2013 compared to $8,625,723 in Q3 2012, a decline of $441,225 (-5%). The year-over-year decline reflects a 10% drop in sale volumes, partially offset by a 5% increase in the average realized price. For the nine months ended September 30, 2013, crude oil revenues totaled $24,085,322 compared to $14,790,021 for the nine months ended September 30, 2012, an increase of $9,295,301 (+63%). The increase for the nine months ended September 30, 2013, reflects a 61% increase in sale volumes and a 1% increase in the average realized price.

NGL revenues totaled $113,880 in Q3 2013 compared to $890,182 in Q3 2012, a decline of $776,303 (-87%). The year-over-year decline reflects an 80% drop in sales volumes and a 37% decrease in the average realized price. For the nine months ended September 30, 2013, NGL revenues totaled $631,376 compared to $1,289,527 for the nine months ended September 30, 2012, a decline of $658,151 (-51%). The decline for the nine months ended September 30, 2013, reflects a 35% drop in sales volumes and a 25% decrease in the average realized price.

Natural gas revenues totaled $2,331,859 in Q3 2013 compared to $3,478,439 in Q3 2012, a decline of $1,146,580 (-33%). The year-over-year decline reflects a 41% drop in sales volumes, partially offset by a 13% increase in the average realized price. For the nine months ended September 30, 2013, natural gas revenues totaled $8,203,321 compared to $6,060,924 for the nine months ended September 30, 2012, an increase of $2,142,397 (+35%). The increase for the nine months ended September 30, 2013, reflects a 4% increase in sale volumes and a 30% increase in the average realized price.

Total revenues totaled $10,630,237 in Q3 2013 compared to $12,997,594 in Q3 2012, a decline of $2,367,357 (-18%). The year-over-year decline reflects a 36% drop in sale volumes, partially offset by a 28% increase in the average realized price. Q3 2013 revenues were comprised of 77% crude oil, 1% NGLs, and 22% natural gas. For the nine months ended September 30, 2013, total revenues totaled $32,920,020 compared to $22,159,397 for the nine months ended September 30, 2012, an increase of $10,760,623 (+49%). The increase for the nine months ended September 30, 2013, reflects a 16% increase in sale volumes and a 28% increase in the average realized price.

Expenses

Lease operating expenses totaled $2,791,161 in Q3 2013 compared to $3,381,855 in Q3 2012, a decline of $590,694 (-17%). For the nine months ended September 30, 2013, lease operating expenses totaled $9,415,848 compared to $8,412,238 for the nine months ended September 30, 2012, an increase of $1,003,610 (+12%). Higher lease operating expenses for the nine months ended September 30, 2013, primarily reflect increased costs at Vermilion 376, where the Company completed three new wells in June, 2012. The lower lease operating expenses recorded in Q3 2013 primarily reflect reduced costs associated with the Company's non-producing properties. Lease operating expenses averaged $14.17 per BOE in Q3 2013 compared to $10.96 per BOE in Q3 2012, which represents a 29% increase in per unit operating expenses. For the nine months ended September 30, 2013, lease operating expenses averaged $14.49 per BOE compared to $14.97 per BOE for the nine months ended September 30, 2012, which represents a 3% decline in per unit operating expenses. The higher Q3 2013 per unit expenses was due primarily to increased fixed costs associated with new wells brought online in 2012.

Depreciation and depletion expenses totaled $2,142,053 in Q3 2013 compared to $2,579,192 in Q3 2012, a decline of $437,139 (-17%). For the nine months ended September 30, 2013, depreciation and depletion expenses totaled $6,806,797 compared to $5,162,590 for the nine months ended September 30, 2012, an increase of $1,644,207 (+32%). Lower depreciation and depletion expenses in Q3 2013 reflect lower production volumes, while higher depreciation and depletion expenses for the nine months ended September 30, 2013, reflect higher production volumes. Depreciation and depletion expenses averaged $10.88 per BOE in Q3 2013 compared to $8.36 per BOE in Q3 2012, which represents a 30% increase in per unit expenses. For the nine months ended September 30, 2013, depreciation and depletion expenses averaged $10.48 per BOE compared to $9.19 per BOE for the nine months ended September 30, 2012, which represents a 14% increase in per unit operating expenses.

General and administrative expenses totaled $1,243,870 in Q3 2013 compared to $1,009,100 in Q3 2012, an increase of $234,770 (+23%). For the nine months ended September 30, 2013, general and administrative expenses totaled $3,737,816 compared to $2,174,207 for the nine months ended September 30, 2012, an increase of $1,563,609 (+72%). The increases primarily reflect higher director and employee compensation. General and administrative expenses averaged $6.32 per BOE in Q3 2013 compared to $3.27 per BOE in Q3 2012, which represents a 93% increase in per unit expenses. For the nine months ended September 30, 2013, general and administrative expenses averaged $5.75 per BOE compared to $3.87 per BOE for the nine months ended September 30, 2012, which represents a 49% increase in per unit operating expenses.

Exploration and evaluation expenses totaled $3,205 in Q3 2013 and $2,162,364 for the nine months ended September 30, 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.

Bad debt expenses totaled $125,584 in Q3 2013 and $2,796,446 for the nine months ended September 30, 2013. The majority of the bad debt expense relates to an allowance for the non-payment of capital and operating expenses by the owner of a participating interest in two wells at Vermilion 376 (see “Legal Proceedings”).

Stock-based compensation expenses totaled $200,085 in Q3 2013 and $595,382 for the nine months ended September 30, 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 $1,861,305 (cash expenses totaled $690,000) in Q3 2013 and $4,426,071 for the nine months ended September 30, 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 the Notes (see “Liquidity”); and 3) accretion of the Company’s liability for asset retirement obligations (ARO).

Other gains (losses) totaled $921,000 in Q3 2013 and ($543,000) for the nine months ended September 30, 2013. Other items relate to unrealized gains or losses on financing warrants issued in conjunction with the 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 Q3 2013.

Deferred tax expense (recovery) totaled $1,161,000 in Q3 2013 and $1,076,000 for the nine months ended September 30, 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 nine months ended September 30, 2013, were partially offset by adjustments to prior period tax estimates.

Net Income

Net income (loss) totaled $2,022,974 in Q3 2013 compared to $5,020,879 in Q3 2012, a decline of $2,997,905. For the nine months ended September 30, 2013, net income totaled $1,360,296 compared to $2,105,169 for the nine months ended September 30, 2012, a decline of $744,873. Net income recorded in Q3 2013 and for the nine months ended September 30, 2013, was weighed down by numerous non-cash charges, including bad debt expense, accrued interest, debt accretion, gains or losses associated with the financing warrants, and deferred taxes.

Funds generated from operations (including dry hole costs) totaled $5,138,203 in Q3 2013, compared to $8,213,653 in Q3 2012, a decrease of $3,075,450 (see Non-IFRS Financial Measures on page 9). For the nine months ended September 30, 2013, funds generated from operations including dry hole costs totaled $11,935,400, compared to $8,138,552 incurred in the nine months ended September 30, 2012, an increase of $3,796,648. The increase in funds generated from operations (including dry hole costs) for the nine months ended September 30, 2013, is primarily the result of higher production volumes from Vermilion 376, Grand Isle 70 and East Cameron 37, partially offset by higher operating, dry hole, and finance expenses. Funds generated from operations (including dry hole costs) in Q3 2013 were lower than year-ago levels due to higher operating and finance expenses and lower production volumes.

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 September 30,		For the nine months ended September 30,	
	2013	2012	2013	2012
Cash provided (used) by operating activities	7,597,655	(5,914,434)	17,263,869	(1,835,609)
Change in non-cash working capital items	(2,501,417)	13,715,298	(3,935,255)	7,427,466
Cash abandonment costs	45,170	412,789	769,150	2,546,695
Dry hole costs	(3,205)	-	(2,162,364)	-
Funds generated from operations (including dry hole costs)	5,138,203	8,213,653	11,935,400	8,138,552

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 Q3 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 financial statements.

	For the three months ended							
	Sep. 30, 2013	Jun. 30, 2013	Mar. 31, 2013	Dec. 31, 2012	Sep. 30, 2012	Jun. 30, 2012	Mar. 31 2012	Dec. 31, 2011
Revenues	$ 10,630,237	$ 10,731,229	$ 11,558,554	$ 12,061,865	$ 12,997,594	$ 5,403,881	$ 3,757,922	$ 4,941,551
Income (loss)	2,022,974	58,796	(721,474)	(5,792,837)	5,020,879	(619,091)	(2,296,620)	1,415,397
Net income (loss)	2,022,974	58,796	(721,474)	(5,792,837)	5,020,879	(619,091)	(2,296,620)	1,415,397
Net income (loss) per share - basic	0.02	0.00	(0.01)	(0.05)	0.05	(0.01)	(0.03)	0.02
Net income (loss) per share - diluted	0.02	0.00	(0.01)	(0.05)	0.05	(0.01)	(0.03)	0.02
OPERATIONS								
Sales								
Oil (Bbl)	75,096	76,498	74,565	78,242	82,984	30,903	26,279	32,962
NGL (Bbl)	5,990	8,816	9,876	19,592	29,581	6,483	1,930	5,901
Natural gas (Mcf)	695,145	752,227	946,163	969,198	1,175,480	811,970	315,513	252,355
Oil (BOE) (1)	196,944	210,685	242,135	259,368	308,478	172,714	80,795	80,922
Oil (BOE/day) (1)	2,141	2,315	2,690	2,819	3,353	1,898	888	880
Oil ($/Bbl)	$ 108.99	$ 103.63	$ 106.93	$ 103.48	$ 103.94	$ 104.80	$ 111.33	$ 111.25
NGL ($/Bbl)	19.01	26.00	29.20	30.12	30.09	47.14	48.56	59.12
Natural gas ($/Mcf)	3.35	3.42	3.48	3.48	2.96	2.28	2.31	3.48
Operating revenue								
Oil	$ 8,184,498	$ 7,927,741	$ 7,973,082	$ 8,096,185	$ 8,625,723	$ 3,238,659	$ 2,925,639	$ 3,666,860
NGL	113,880	229,173	288,325	590,160	890,182	305,607	93,738	348,914
Natural gas	2,331,859	2,574,315	3,297,147	3,375,520	3,478,439	1,852,868	729,617	879,207
Handling fees	-	-	-	-	3,250	6,747	8,927	46,570
Total	10,630,237	10,731,229	11,558,554	12,061,865	12,997,594	5,403,881	3,757,922	4,941,551
Expenses								
Lease operating expense	2,791,161	3,299,099	3,325,587	3,497,410	3,381,855	2,736,580	2,293,803	1,827,721
Lease operating expense per BOE (1)	14.17	15.66	13.73	13.48	10.96	15.84	28.39	22.59

(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 and the administrative agent for a lending group entered into a note purchase agreement ("Note Purchase Agreement") under which Rooster Oil & Gas, LLC, and Probe Resources US Ltd., as Co-Issuers, issued 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 Note Purchase Agreement 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 Note Purchase Agreement. Pursuant to same, the Company and the Note holders agreed to covenant revisions related to altering 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 two related parties who are significant shareholders and/or directors of the Company 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 of ($3,783,627 USD). The interest rate is 9% on all advances, and the credit facility matures 181 days following full satisfaction of the terms of the existing Note Purchase Agreement, 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.

At September 30, 2013, the Company had a working capital deficiency of $10,905,428; pro forma for the CDN $4.0 million advance under the secured credit facility (net of related fees), the working capital deficit was $7,624,876. Management believes that expected future cash flow from operations will be sufficient to settle its trade accounts payable and other current liabilities in due course. 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.

Asset Retirement Obligations

In addition to the amounts owed at September 30, 2013, the Company has an ongoing liability with respect to the decommissioning of wells and facilities totaling $17,728,646. 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.

Contractual Obligations

At September 30, 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)]	20,597,796	-	20,597,796	-	-
	$ 27,060,796	$ -	$ 27,060,796	$ -	$ -

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

(2) $22,500,000 payable on October 22, 2014 with interest at 12% payable quarterly.

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 $16,369,381 in Q3 2013 compared to $676,390 in Q3 2012, an increase of $15,692,991. Capital expenditures in Q3 2013 primarily reflect drilling expenditures related to the High Island A494 #B-4 well.

In addition, during the first nine months of 2013 the Company recorded a $2,162,364 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. Last year the Company expensed $4,031,388 of charges incurred through year-end 2012 in connection with drilling the well. The charges incurred in the nine months ended September 30, 2013, relate to additional expenses incurred subsequent to year-end.

Off-Balance Sheet Arrangements

At September 30, 2013 the Company is not party to, and not currently party to, any off-balance sheet arrangements.

Financial Instruments and Other Instruments

As of September 30, 2013, the Company has three fixed price physical delivery contracts pursuant to which it has agreed to sell certain quantities of natural gas and crude oil. The fixed price physical delivery contracts are as follows:

- For the period April 1, 2013, through October 31, 2013, the Company is obligated to sell approximately 6,000 MMBtu per day (3,100 MMBtu per day net to the Company's working interest) of natural gas from East Cameron 36/37 at a fixed price of $3.60 per MMBtu.

- For the period October 1, 2013, through October 31, 2013, the Company is obligated to sell all owned or controlled crude oil produced from Vermilion 376 (approximately 1,000 barrels per day) at a fixed price of $105 per barrel less discounts.
- For the period November 1, 2013, through April 30, 2014, the Company is obligated to sell 350 net barrels per day of crude oil at a fixed price of $102.95 per barrel less discounts.

At September 30, 2013, the Company did not have, and currently does not have, any derivative securities, financial or other instruments.

Transactions with Related Parties

During the quarter ended September 30, 2013, the Company was party to the following transactions with related parties:

- Accounts payable and accrued liabilities to directors and/or entities associated with directors, totaled $109,000 at September 30, 2013. In addition, at September 30, 2013, the Company had accounts payable in the amount of $3,661,899 due and owing to Chet Morrison Contractors, LLC, which is indirectly 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 $1,087,406. 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.

- Cochon Properties, LLC, and Cretaceous, LLC, are participating in the High Island A494 #B-4 well with 6.25% and 1.25% working interests, respectively. Cochon Properties, LLC, is owned by Chester F. Morrison, Jr., who is Chairman of the Board of the Company. Cretaceous, LLC, is owned by Robert P. Murphy, who is President, CEO 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. At September 30, 2013 Cochon and Cretaceous had prepaid balances of $1,148,805.

Subsequent to the quarter ended September 30, 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”). The K2 Principal Fund L.P. serves as “Administrative Agent” under the credit facility. K2 is also a participating lender in the credit facility along with Chester F. Morrison, Jr. Both K2 and Mr. Morrison are related parties to Rooster. None of the participants in the credit facility is a chartered bank, trust company or treasury bank.

For additional events subsequent to the quarter ended September 30, 2013, see “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 1000 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 Note Purchase Agreement, 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 September 30, 2013 there has 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. 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 stock option plan (and the proportionate voting shares (each of which is convertible into 1000 common shares), there were no warrants, stock options or other securities convertible into common shares outstanding on September 30, 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 is only one threatened or pending legal matter that could have a material impact on our consolidated results of operations, financial position or cash flows.

In 2012, the Company assigned a 25% participation interest in the Vermilion Area Block 376 #A-3 and #A-4 wells in consideration of the assignee paying it’s agreed to proportionate share of the drilling, completion and lease operating costs. The assignee failed to pay certain invoiced amounts and on November 20, 2012 the Company, as operator of the wells, filed a lien in the amount of $2,264,701.15 against the interest in the wells. Additionally, on March 27, 2013, the Company filed an action to recover all amounts due per the lien in addition to unpaid lease operating expenses, damages, interest, attorney fees, etc. In response, the assignee of the interest and three of its affiliates filed counter-claims against the Company. The assignee *et al* also named certain officers and/or directors of the Company as defendants in the action and the Company has agreed to indemnify and defend those individuals. The Company asserts that it has valid defenses to the counter-claims, and management is of the opinion that it will not be subject to any material damage award in the matter.

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 Well Services, and 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.

In order to enter into the membership interest contribution agreements, 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 forclosure 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.

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 holders of the Notes 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.

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 development of potential oil and gas reserves identified in the High Island A-494 #B-4 well, the ability of the Company to obtain debt or equity financing, 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 risks relate to the uncertainty of the Company’s ability to finance its working capital deficit, development plans and ongoing operations. There can be no assurance that debt or equity financing or cash generated by operations will be available or sufficient to meet these requirements or, if debt or equity financing is available, that it will be on terms acceptable to the Company. The Company’s inability to access sufficient capital could have a material adverse effect on its business financial condition, results of operations and prospects.

Additional risks relate to the results of any such development operations, 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 Amended and Restated MD&A is dated March 31, 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 September 30,		For the nine months ended September 30,	
	2013	2012	2013	2012
EBITDAX [(a)] Calculation:				
Income (loss)	2,022,974	5,020,879	1,360,296	2,105,169
DD&A	2,142,053	2,579,192	6,806,797	5,162,590
Exploration and evaluation	3,205	0	2,162,364	(303,543)
Non-cash plug and abandonment	0	0	0	940,000
Bad debt expense	125,584	0	2,796,446	0
Stock-based compensation	200,085	190,755	595,382	289,885
Finance expenses and unrealized loss on financing warrants	940,305	472,027	4,969,071	833,687
Impairment expense	0	343,786	0	343,786
Deferred tax expense (recovery)	1,161,000	0	1,076,000	0
EBITDAX	6,595,206	8,606,639	19,766,356	9,371,574

(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.