NORTHERN OIL & GAS, INC.
Form 10-Q
November 08, 2012

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-Q

T QUARTERLY REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended September 30, 2012

£ TRANSITION REPORT UNDER SECTION 13 OR 15(d) OF THE EXCHANGE ACT

For the transition period from ____________ to____________

Commission File No. 001-33999

NORTHERN OIL AND GAS, INC.
(Exact name of Registrant as specified in its charter)

Minnesota	95-3848122
(State or Other Jurisdiction of Incorporation or organization)	(I.R.S. Employer Identification No.)

315 Manitoba Avenue – Suite 200
Wayzata, Minnesota 55391
(Address of Principal Executive Offices)

(952) 476-9800
(Registrant's Telephone Number)

N/A
(Former name, former address and former fiscal year,
if changed since last report)

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes T No £

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes T No £

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of “large accelerated filer,” “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act:

Large Accelerated Filer x Accelerated Filer ¨

Non-Accelerated Filer £ Smaller Reporting Company £
(Do not check if a smaller reporting company)

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
Yes £ No T

As of November 5, 2012, there were 63,475,452 shares of our common stock, par value $0.001, outstanding.

GLOSSARY OF TERMS

Unless otherwise indicated in this report, natural gas volumes are stated at the legal pressure base of the state or geographic area in which the reserves are located at 60 degrees Fahrenheit. Crude oil and natural gas equivalents are determined using the ratio of six Mcf of natural gas to one barrel of crude oil, condensate or natural gas liquids.

The following definitions shall apply to the technical terms used in this report.

Terms used to describe quantities of crude oil and natural gas:

“Bbl.” One stock tank barrel of 42 U.S. gallons liquid volume used herein in reference to crude oil, condensate or NGLs.

“Boe.” A barrel of oil equivalent and is a standard convention used to express oil, NGL and natural gas volumes on a comparable oil equivalent basis. Gas equivalents are determined under the relative energy content method by using the ratio of 6.0 Mcf of gas to 1.0 Bbl of oil or NGL.

“Boepd.” Boe per day.

“Btu or British Thermal Unit.” The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

“MBbl.” One thousand barrels of crude oil, condensate or NGLs.

“MBoe.” One thousand Boes.

“Mcf.” One thousand cubic feet of natural gas.

“MMBbl.” One million barrels of crude oil, condensate or NGLs.

“MMBoe.” One million Boes.

“MMBtu.” One million British Thermal Units.

“MMcf.” One million cubic feet of natural gas.

“NGLs.” Natural gas liquids. Hydrocarbons found in natural gas that may be extracted as liquefied petroleum gas and natural gasoline.

Terms used to describe our interests in wells and acreage:

“Basin.” A large natural depression on the earth’s surface in which sediments generally brought by water accumulate.

“Completion.” The process of treating a drilled well followed by the installation of permanent equipment for the production of crude oil, NGLs, and/or natural gas.

“Conventional play.” An area that is believed to be capable of producing crude oil, NGLs, and natural gas occurring in discrete accumulations in structural and stratigraphic traps.

"Developed acreage." Acreage consisting of leased acres spaced or assignable to productive wells. Acreage included in spacing units of infill wells is classified as developed acreage at the time production commences from the initial well in the spacing unit. As such, the addition of an infill well does not have any impact on a company's amount of developed acreage.

"Development well." A well drilled within the proved area of a crude oil, NGL, or natural gas reservoir to the depth of stratigraphic horizon (rock layer or formation) noted to be productive for the purpose of extracting proved crude oil, NGL, or natural gas reserves.

"Dry hole." A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

"Exploratory well" A well drilled to find and produce crude oil, NGLs, or natural gas in an unproved area, to find a new reservoir in a field previously found to be producing crude oil, NGLs, or natural gas in another reservoir, or to extend a known reservoir.

"Field." An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.

"Formation." A layer of rock which has distinct characteristics that differs from nearby rock.

"Gross acres or Gross wells." The total acres or wells, as the case may be, in which a working interest is owned.

"Held by operations." A provision in an oil and gas lease that extends the stated term of the lease as long as drilling operations are ongoing on the property.

"Held by production." A provision in an oil and gas lease that extends the stated term of the lease as long as the property produces a minimum quantity of crude oil, NGLs, and natural gas.

"Hydraulic fracturing." The technique of improving a well's production or injection rates by pumping a mixture of fluids into the formation and rupturing the rock, creating an artificial channel. As part of this technique, sand or other material may also be injected into the formation to keep the channel open, so that fluids or natural gases may more easily flow through the formation.

"Infill well." A subsequent well drilled in an established spacing unit to the addition of an already established productive well in the spacing unit. Acreage on which infill wells are drilled is considered developed commencing with the initial productive well established in the spacing unit. As such, the addition of an infill well does not have any impact on a company's amount of developed acreage.

"Net acres." The percentage ownership of gross acres. Net acres are deemed to exist when the sum of fractional ownership working interests in gross acres equals one (e.g., a 10% working interest in a lease covering 640 gross acres is equivalent to 64 net acres).

"Net well." A well that is deemed to exist when the sum of fractional ownership working interests in gross wells equals one.

"NYMEX." The New York Mercantile Exchange.

"OPEC." The Organization of Petroleum Exporting Countries.

"Productive well." A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.

"Recompletion." The process of treating a drilled well followed by the installation of permanent equipment for the production of crude oil, NGLs or natural gas or, in the case of a dry hole, the reporting of abandonment to the appropriate agency.

“Reservoir.” A porous and permeable underground formation containing a natural accumulation of producible crude oil, NGLs and/or natural gas that is confined by impermeable rock or water barriers and is separate from other reservoirs.

“Spacing.” The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres, e.g., 40-acre spacing, and is often established by regulatory agencies.

“Unconventional play.” An area believed to be capable of producing crude oil, NGLs, and/or natural gas occurring in cumulations that are regionally extensive but require recently developed technologies to achieve profitability. These areas tend to have low permeability and may be closely associated with source rock as this is the case with crude oil and natural gas shale, tight crude oil and natural gas sands and coal bed methane.

“Undeveloped acreage.” Leased acreage on which wells have not been drilled or completed to a point that would permit the production of economic quantities of crude oil, NGLs, and natural gas, regardless of whether such acreage contains proved reserves. Undeveloped acreage includes net acres held by operations until a productive well is established in the spacing unit.

“Unit.” The joining of all or substantially all interests in a reservoir or field, rather than a single tract, to provide for development and operation without regard to separate property interests. Also, the area covered by a unitization agreement.

“Wellbore.” The hole drilled by the bit that is equipped for natural gas production on a completed well. Also called well or borehole.

“West Texas Intermediate or WTI.” A light, sweet blend of oil produced from the fields in West Texas.

“Working interest.” The right granted to the lessee of a property to explore for and to produce and own crude oil, NGLs, natural gas or other minerals. The working interest owners bear the exploration, development, and operating costs on either a cash, penalty, or carried basis.

Terms used to assign a present value to or to classify our reserves:

“Possible reserves.” The additional reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than probable reserves.

“Pre-tax PV-10% or PV-10.” The estimated future net revenue, discounted at a rate of 10% per annum, before income taxes and with no price or cost escalation or de-escalation in accordance with guidelines promulgated by the SEC.

“Probable reserves.” The additional reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than proved reserves but which together with proved reserves, are as likely as not to be recovered.

“Proved developed producing reserves (PDP’s).” Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional crude oil, NGLs, and natural gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery are included in “proved developed reserves” only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

“Proved developed non-producing reserves (PDNP’s).” Proved crude oil, NGLs, and natural gas reserves that are developed behind pipe, shut-in or that can be recovered through improved recovery only after the necessary equipment has been installed, or when the costs to do so are relatively minor. Shut-in reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not started producing, (2) wells that were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe reserves are expected to be recovered from zones in existing wells that will require additional completion work or future recompletion prior to the start of production.

“Proved reserves.” The quantities of crude oil, NGLs and natural gas, which, by analysis of geosciences and engineering data, can be estimated with reasonable certainty to be economically producible, from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations, prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

"Proved undeveloped drilling location." A site on which a development well can be drilled consistent with spacing rules for purposes of recovering proved undeveloped reserves.

"Proved undeveloped reserves" or "PUDs." Reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for development. Reserves on undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units are claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Estimates for proved undeveloped reserves will not be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

(i) The area of the reservoir considered as proved includes: (A) the area identified by drilling and limited by fluid contacts, if any, and (B) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible crude oil, NGLs or natural gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons ("LKH") as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil ("HKO") elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when: (A) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (B) the project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based on future conditions.

"Standardized measure." The estimated future net revenue, discounted at a rate of 10% per annum, after income taxes and with no price or cost escalation, calculated in accordance with Accounting Standards Codification ("ASC") 932, formerly Statement of Financial Accounting Standards No. 69 "Disclosures About Oil and Gas Producing Activities."

NORTHERN OIL AND GAS, INC.
FORM 10-Q

September 30, 2012

C O N T E N T S

PART I - FINANCIAL INFORMATION

Item 1. Financial Statements.

NORTHERN OIL AND GAS, INC.
BALANCE SHEETS
SEPTEMBER 30, 2012 AND DECEMBER 31, 2011

	September 30, 2012 (UNAUDITED)	December 31, 2011
CURRENT ASSETS		
Cash and Cash Equivalents	$ 8,234,566	$ 6,279,587
Trade Receivables	79,324,983	51,418,830
Advances to Operators	4,050,511	17,530,474
Prepaid Expenses	758,476	486,421
Other Current Assets	280,052	317,460
Derivative Instruments	4,005,611	-
Deferred Tax Asset	-	4,472,000
Total Current Assets	96,654,199	80,504,772
PROPERTY AND EQUIPMENT		
Oil and Natural Gas Properties, Full Cost Method of Accounting		
Proved	1,051,333,841	566,195,321
Unproved	104,910,316	137,784,903
Other Property and Equipment	3,173,798	2,988,641
Total Property and Equipment	1,159,417,955	706,968,865
Less - Accumulated Depreciation and Depletion	135,352,039	63,265,919
Total Property and Equipment, Net	1,024,065,916	643,702,946
DERIVATIVE INSTRUMENTS	2,283,655	-
DEBT ISSUANCE COSTS	12,211,806	1,386,201
TOTAL ASSETS	$ 1,135,215,576	$ 725,593,919
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Accounts Payable	$ 122,259,062	$ 110,133,286
Accrued Expenses	2,769,351	65,443
Accrued Interest	9,022,667	98,798
Derivative Instruments	-	9,363,068
Deferred Tax Liability	709,000	-
Total Current Liabilities	134,760,080	119,660,595
LONG-TERM LIABILITIES		
Revolving Credit Facility	68,000,000	69,900,000
8% Senior Notes Due 2020	300,000,000	-
Derivative Instruments	-	2,574,903
Other Noncurrent Liabilities	1,422,683	959,366
Deferred Tax Liability	65,657,000	35,929,000

Total Long-Term Liabilities	435,079,683	109,363,269
TOTAL LIABILITIES	569,839,763	229,023,864
COMMITMENTS AND CONTINGENCIES (NOTE 8)		
STOCKHOLDERS' EQUITY		
Preferred Stock, Par Value $.001; 5,000,000 Authorized, No Shares Outstanding	-	-
Common Stock, Par Value $.001; 95,000,000 Authorized, (9/30/2012 – 63,490,667 Shares Outstanding and 12/31/2011 – 63,330,421 Shares Outstanding)	63,491	63,330
Additional Paid-In Capital	464,209,170	448,198,350
Retained Earnings	101,103,152	48,370,684
Accumulated Other Comprehensive Loss	-	(62,309)
Total Stockholders' Equity	565,375,813	496,570,055
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$1,135,215,576	$725,593,919

The accompanying notes are an integral part of these financial statements.

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NORTHERN OIL AND GAS, INC.
STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
FOR THE THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2012 AND 2011
(UNAUDITED)

	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
REVENUES				
Oil and Gas Sales	$80,690,301	$43,680,619	$216,268,712	$106,203,904
Gain (Loss) on Settled Derivatives	1,701,296	(1,824,719)	(4,729,186)	(10,695,006)
Unrealized (Loss) Gain on Derivative Instruments	(22,308,470)	27,105,400	18,125,928	26,675,003
Other Revenue	12,486	88,738	160,752	218,984
Total Revenues	60,095,613	69,050,038	229,826,206	122,402,885
OPERATING EXPENSES				
Production Expenses	8,734,636	3,910,859	22,540,237	8,542,761
Production Taxes	8,092,843	4,261,407	20,829,732	10,188,308
General and Administrative Expense	9,467,711	4,073,988	18,568,696	10,113,995
Depletion of Oil and Gas Properties	27,952,585	10,749,384	71,781,894	25,962,463
Depreciation and Amortization	104,830	75,597	304,226	214,205
Accretion of Discount on Asset Retirement Obligations	23,709	7,781	61,162	20,305
Total Expenses	54,376,314	23,079,016	134,085,947	55,042,037
INCOME FROM OPERATIONS	5,719,299	45,971,022	95,740,259	67,360,848
OTHER INCOME (EXPENSE)				
Interest Expense	(5,205,822)	(182,499)	(8,130,225)	(425,687)
Interest Income	106	1,699	1,206	567,327
Gain on Available for Sale Securities	-	-	-	215,092
Total Other Income (Expense)	(5,205,716)	(180,800)	(8,129,019)	356,732
INCOME BEFORE INCOME TAXES	513,583	45,790,222	87,611,240	67,717,580
INCOME TAX PROVISION	213,422	17,173,000	34,878,772	25,725,300
NET INCOME	$300,161	$28,617,222	$52,732,468	$41,992,280
OTHER COMPREHENSIVE INCOME, NET OF TAX				
Unrealized Gains on Marketable Securities (Net of Tax of $109,000 for the nine months ended September 30, 2011)	-	-	-	173,846
Reclassification of Derivative Instruments Included in Income (Net of Tax of $119,000 for the three months ended September 30, 2011 and $39,000 and $331,000	-	176,950	62,309	518,900

for the nine months ended September 30, 2012 and 2011, respectively)				
Total Other Comprehensive Income	$-	$176,950	$62,309	$692,746
COMPREHENSIVE INCOME	$300,161	$28,794,172	$52,794,777	$42,685,026
Net Income Per Common Share – Basic	$0.00	$0.46	$0.84	$0.68
Net Income Per Common Share – Diluted	$0.00	$0.46	$0.84	$0.68
Weighted Average Shares Outstanding – Basic	62,589,256	61,919,641	62,410,110	61,708,537
Weighted Average Shares Outstanding – Diluted	62,882,673	62,265,502	62,753,241	62,114,115

The accompanying notes are an integral part of these financial statements.

NORTHERN OIL AND GAS, INC.
STATEMENTS OF CASH FLOWS
FOR THE NINE MONTHS ENDED SEPTEMBER 30, 2012 AND 2011
(UNAUDITED)

	Nine Months Ended September 30, 2012	2011
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$52,732,468	$41,992,280
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities:		
Depletion of Oil and Gas Properties	71,781,894	25,962,463
Depreciation and Amortization	304,226	214,205
Amortization of Debt Issuance Costs	1,025,009	286,969
Accretion of Discount on Asset Retirement Obligations	61,162	20,305
Deferred Income Taxes	34,870,000	25,723,000
Net Gain on Sale of Available for Sale Securities	-	(215,092)
Unrealized Gain on Derivative Instruments	(18,125,928)	(26,675,003)
Amortization of Deferred Rent	(24,921)	(13,931)
Share - Based Compensation Expense	11,295,664	5,552,245
Changes in Working Capital and Other Items:		
Increase in Trade Receivables	(27,906,153)	(22,527,820)
Increase in Prepaid Expenses	(272,055)	(111,797)
Decrease in Other Current Assets	37,408	185,661
Decrease in Accounts Payable	(723,549)	(1,028,434)
Increase in Accrued Interest	8,923,869	20,475
Increase in Accrued Expenses	2,717,838	340
Net Cash Provided By Operating Activities	136,696,932	49,385,866
CASH FLOWS FROM INVESTING ACTIVITIES		
Purchases of Oil and Gas Properties and Development Capital Expenditures	(419,687,257)	(239,762,074)
Advances to Operators	-	(14,790,456)
Proceeds from Sale of Oil and Gas Properties	-	5,027,162
Proceeds from Sale of Available for Sale Securities	-	58,606,328
Purchases of Available for Sale Securities	-	(18,381,690)
Purchases of Other Equipment and Furniture	(185,157)	(181,041)
Net Cash Used For Investing Activities	(419,872,414)	(209,481,771)
CASH FLOWS FROM FINANCING ACTIVITIES		
Advances on Revolving Credit Facility	409,600,000	21,000,000
Repayments on Revolving Credit Facility	(411,500,000)	(6,000,000)
Issuances of 8% Senior Notes Due 2020	300,000,000	-
Debt Issuance Costs Paid	(11,850,614)	(249,147)
Repurchase of Common Stock	(1,173,315)	-
Proceeds from Exercise of Stock Options	54,390	-
Proceeds from Exercise of Warrants	-	1,500,000
Net Cash Provided by Financing Activities	285,130,461	16,250,853

NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	1,954,979	(143,845,052)
CASH AND CASH EQUIVALENTS – BEGINNING OF PERIOD	6,279,587	152,110,701
CASH AND CASH EQUIVALENTS – END OF PERIOD	$8,234,566	$8,265,649
Supplemental Disclosure of Cash Flow Information		
Cash Paid During the Period for Interest	$2,226,598	$17,965
Cash Paid During the Period for Income Taxes	$8,772	$2,300
Non-Cash Financing and Investing Activities:		
Payment of Compensation through Issuance of Common Stock	$17,129,906	$17,391,413
Capitalized Asset Retirement Obligations	$413,146	$259,832
Non-Cash Compensation Capitalized in Oil and Gas Properties	$5,834,242	$10,308,464

The accompanying notes are an integral part of these financial statements.

NOTES TO UNAUDITED CONDENSED FINANCIAL STATEMENTS
SEPTEMBER 30, 2012
(Unaudited)

NOTE 1 ORGANIZATION AND NATURE OF BUSINESS

Northern Oil and Gas, Inc. (the "Company," "Northern," "our" and words of similar import), a Minnesota corporation, is an independent energy company engaged in the acquisition, exploration, exploitation, development and production of crude oil and natural gas properties. The Company's common stock trades on the NYSE MKT market under the symbol "NOG".

Northern's principal business is crude oil and natural gas exploration, development, and production with operations in North Dakota and Montana that primarily target the Bakken and Three Forks formations in the Williston Basin of the United States. The Company acquires leasehold interests that comprise of non-operated working interests in wells and in drilling projects within its area of operations. As of September 30, 2012, approximately 47% of the Company's 183,788 total net acres were developed.

NOTE 2 SIGNIFICANT ACCOUNTING POLICIES

The financial information included herein is unaudited, except for the balance sheet as of December 31, 2011, which has been derived from the Company's audited financial statements for the year ended December 31, 2011. However, such information includes all adjustments (consisting of normal recurring adjustments and change in accounting principles), which are in the opinion of management, necessary for a fair presentation of financial position, results of operations and cash flows for the interim periods. The results of operations for interim periods are not necessarily indicative of the results to be expected for an entire year.

Certain information, accounting policies, and footnote disclosures normally included in the financial statements prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP") have been omitted in this Form 10-Q pursuant to certain rules and regulations of the Securities and Exchange Commission ("SEC"). The financial statements should be read in conjunction with the audited financial statements for the year ended December 31, 2011, which were included in the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2011.

Use of Estimates

The preparation of these financial statements under GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The most significant estimates relate to proved crude oil and natural gas reserve volumes, future development costs, estimates relating to certain crude oil and natural gas revenues and expenses, fair value of derivative instruments, and deferred income taxes. Actual results may differ from those estimates.

Cash and Cash Equivalents

The Company considers highly liquid investments with insignificant interest rate risk and original maturities to the Company of three months or less to be cash equivalents. Cash equivalents consist primarily of interest-bearing bank accounts and money market funds. The Company's cash positions represent assets held in checking and money market accounts. These assets are generally available on a daily or weekly basis and are highly liquid in nature. Due to the balances being greater than $250,000, the Company does not have FDIC coverage on the entire amount of bank deposits. The Company believes this risk is minimal. In addition, the Company is subject to Security Investor Protection Corporation (SIPC) protection on a vast majority of its financial assets.

Other Property and Equipment

Property and equipment that are not crude oil and natural gas properties are recorded at cost and depreciated using the straight-line method over their estimated useful lives of three to fifteen years. Expenditures for replacements, renewals, and betterments are capitalized. Maintenance and repairs are charged to operations as incurred. Long-lived assets, other than crude oil and natural gas properties, are evaluated for impairment to determine if current circumstances and market conditions indicate the carrying amount may not be recoverable. The Company has not recognized any impairment losses on non-crude oil and natural gas long-lived assets. Depreciation expense was $104,830 and $75,597 for the three months ended September 30, 2012 and 2011, respectively. Depreciation expense was $304,226 and $214,205 for the nine months ended September 30, 2012 and 2011, respectively.

Full Cost Method

The Company follows the full cost method of accounting for crude oil and natural gas operations whereby all costs related to the exploration and development of crude oil and natural gas properties are initially capitalized into a single cost center ("full cost pool"). Such costs include land acquisition costs, geological and geophysical expenses, carrying charges on non-producing properties, costs of drilling directly related to acquisition, and exploration activities. Internal costs that are capitalized are directly attributable to acquisition, exploration and development activities and do not include costs related to the production, general corporate overhead or similar activities. Costs associated with production and general corporate activities are expensed in the period incurred. Capitalized costs are summarized as follows for the three and nine months ended September 30, 2012 and 2011, respectively.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Capitalized Certain Payroll and Other Internal Costs	$79,471	$3,760,296	$7,366,101	$13,364,427
Capitalized Interest Costs	$1,811,088	-	4,426,429	-
Total	$1,890,559	$3,760,296	$11,792,530	$13,364,427

As of September 30, 2012, the Company held leasehold interests in the Williston Basin on acreage located in North Dakota and Montana targeting the Bakken and Three Forks formations.

Proceeds from property sales will generally be credited to the full cost pool, with no gain or loss recognized, unless such a sale would significantly alter the relationship between capitalized costs and the proved reserves attributable to these costs. A significant alteration would typically involve a sale of 25% or more of the proved reserves related to a single full cost pool. The Company received $5.0 million of proceeds from property sales in the nine months ended September 30, 2011, which was credited to the full cost pool. There were no proceeds from property sales in the nine months ended September 30, 2012.

Capitalized costs associated with impaired properties and capitalized cost related to properties having proved reserves, plus the estimated future development costs and asset retirement costs, are depleted and amortized on the unit-of-production method based on the estimated gross proved reserves. The costs of unproved properties are withheld from the depletion base until such time as they are either developed or abandoned. When proved reserves are assigned or the property is considered to be impaired, the cost of the property or the amount of the impairment is added to costs subject to depletion and full cost ceiling calculations. For the three months ended September 30, 2012 and 2011, the Company transferred into the full cost pool costs related to expired leases of $0.5 million and $2.5 million, respectively. For the nine months ended September 30, 2012 and 2011, the Company transferred into the full cost pool costs related to expired leases of $3.1 million and $8.1 million, respectively.

Capitalized costs of crude oil and natural gas properties (net of related deferred income taxes) may not exceed an amount equal to the present value, discounted at 10% per annum, of the estimated future net cash flows from proved crude oil and natural gas reserves plus the cost of unproved properties (adjusted for related income tax effects). Should capitalized costs exceed this ceiling, impairment is recognized. The present value of estimated future net cash flows is computed by applying the 12-month average price of crude oil and natural gas to estimated future production of proved crude oil and natural gas reserves as of period-end, less estimated future expenditures to be incurred in developing and producing the proved reserves and assuming continuation of existing economic conditions. Such present value of proved reserves' future net cash flows excludes future cash outflows associated with settling asset retirement obligations that have been accrued on the balance sheet. Should this comparison indicate an excess carrying value, the excess is charged to earnings as an impairment expense. As of September 30, 2012, the Company has not realized any impairment of its properties.

Asset Retirement Obligations

Asset retirement obligation is included in other noncurrent liabilities and relates to future costs associated with the plugging and abandonment of crude oil and natural gas wells, removal of equipment and facilities from leased acreage and returning the land to its original condition. Estimates are based on estimated remaining lives of those wells based on reserve estimates, external estimates to plug and abandon the wells in the future and federal and state regulatory requirements. The liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset.

Debt Issuance Costs

The Company capitalized $5.8 million and $8.8 million of costs incurred in connection with the revolving credit facility and senior unsecured notes, respectively (see Note 4). These debt issuance costs are being amortized over the term of the related financing using the straight-line method, which approximates the effective interest method.

The amortization of debt issuance costs for the three months ended September 30, 2012 and 2011 was $492,745 and $106,629, respectively. The amortization of debt issuance costs for the nine months ended September 30, 2012 and 2011 was $1,025,009 and $286,969, respectively.

Revenue Recognition

The Company recognizes crude oil and natural gas revenues from its interests in producing wells when production is delivered to, and title has transferred to, the purchaser and to the extent the selling price is reasonably determinable. The Company uses the sales method of accounting for natural gas balancing of natural gas production and would recognize a liability if the existing proven reserves were not adequate to cover the current imbalance situation. As of September 30, 2012 and December 31, 2011, the Company's natural gas production was in balance, meaning its cumulative portion of natural gas production taken and sold from wells in which it has an interest equaled its entitled interest in natural gas production from those wells.

Stock-Based Compensation

The Company records expense associated with the fair value of stock-based compensation. For fully vested stock and restricted stock grants the Company calculates the stock based compensation expense based upon estimated fair value on the date of grant. For stock options, the Company uses the Black-Scholes option valuation model to calculate stock based compensation at the date of grant. Option pricing models require the input of highly subjective assumptions, including the expected price volatility. Changes in these assumptions can materially affect the fair value estimate.

Stock Issuance

The Company records the stock-based compensation awards issued to non-employees and other external entities for goods and services at either the fair market value of the goods received or services rendered or the instruments issued in exchange for such services, whichever is more readily determinable.

Income Taxes

Deferred income tax assets and liabilities are determined based upon differences between the financial reporting and tax bases of assets and liabilities and are measured using the enacted tax rates and laws that will be in effect when the differences are expected to reverse. Accounting standards require the consideration of a valuation allowance for deferred tax assets if it is "more likely than not" that some component or all of the benefits of deferred tax assets will not be realized. No valuation allowance has been recorded as of September 30, 2012 and December 31, 2011.

Net Income Per Common Share

Basic earnings per share ("EPS") are computed by dividing net income (the numerator) by the weighted average number of common shares outstanding for the period (the denominator). Diluted EPS is computed by dividing net income by the weighted average number of common shares and potential common shares outstanding (if dilutive) during each period. Potential common shares include stock options, warrants and restricted stock. The number of potential common shares outstanding relating to stock options, warrants and restricted stock is computed using the treasury stock method.

The reconciliation of the denominators used to calculate basic EPS and diluted EPS for the three and nine months ended September 30, 2012 and 2011 are as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Weighted average common shares outstanding – basic	62,589,256	61,919,641	62,410,110	61,708,537
Plus: Potentially dilutive common shares				
Stock options, warrants, and restricted stock	293,417	345,861	343,131	405,578
Weighted average common shares outstanding – diluted	62,882,673	62,265,502	62,753,241	62,114,115
Restricted stock excluded from EPS due to the anti-dilutive effect	34,702	44,242	23,099	37,065

Derivative Instruments and Price Risk Management

The Company uses derivative instruments to manage market risks resulting from fluctuations in the prices of crude oil. The Company enters into derivative contracts, including price swaps, caps and floors, which require payments to (or receipts from) counterparties based on the differential between a fixed price and a variable price for a fixed quantity of crude oil without the exchange of underlying volumes. The notional amounts of these financial instruments are based on expected production from existing wells. The Company has, and may continue to use exchange traded futures contracts and option contracts to hedge the delivery price of crude oil at a future date.

On November 1, 2009, due to the volatility of price differentials in the Williston Basin, the Company de-designated all derivatives that were previously classified as cash flow hedges and in addition, the Company has elected not to designate any subsequent derivative contracts as accounting hedges. As such, all derivative positions are carried at their fair value on the balance sheet and are marked-to-market at the end of each period. Any realized gains and losses are recorded to gain (loss) on settled derivatives and unrealized mark-to-market gains or losses are recorded to unrealized gain (loss) on derivative instruments on the statements of income and comprehensive income rather than as a component of accumulated other comprehensive income (loss) or other income (expense). See Note 12 for a description of the derivative contracts which the Company has entered into.

Prior to November 1, 2009, the Company, at the inception of a derivative contract, designated the derivative as a cash flow hedge. For all derivatives designated as cash flow hedges, the Company formally documented the relationship between the derivative contract and the hedged items, as well as the risk management objective for entering into the derivative contract. To be designated as a cash flow hedge transaction, the relationship between the derivative and the hedged items must be highly effective in achieving the offset of changes in cash flows attributable to the risk both at the inception of the derivative and on an ongoing basis. The Company historically measured hedge effectiveness on a quarterly basis and hedge accounting would be discontinued prospectively if it determined that the derivative was no longer effective in offsetting changes in the cash flows of the hedged item. Gains and losses deferred in accumulated other comprehensive income (loss) related to cash flow hedge derivatives that become ineffective remain unchanged until the related production was delivered. If the Company determines that it was probable that a hedged forecasted transaction would not occur, deferred gains or losses on the derivative were recognized in earnings immediately.

Derivatives, historically, were recorded on the balance sheet at fair value and changes in the fair value of derivatives were recorded each period in current earnings or other comprehensive income (loss), depending on whether a derivative was designated as part of a hedge transaction and, if it was, depending on the type of hedge transaction. The Company's derivatives historically consisted primarily of cash flow hedge transactions in which the Company was hedging the variability of cash flows related to a forecasted transaction. Period to period changes in the fair value of derivative instruments designated as cash flow hedges were reported in accumulated other comprehensive income (loss) and reclassified to earnings in the periods in which the hedged item impacts earnings. The ineffective portion of the cash flow hedges were reflected in current period earnings as gain or loss from derivatives. Gains and losses on derivative instruments that did not qualify for hedge accounting were included in income or loss from derivatives in the period in which they occur. The resulting cash flows from derivatives were reported as cash flows from operating activities.

Impairment

Long-lived assets to be held and used are required to be reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Crude oil and natural gas properties accounted for using the full cost method of accounting (which the Company uses) are excluded from this requirement but continue to be subject to the full cost method's impairment rules. There was no impairment identified as of September 30, 2012 and December 31, 2011.

New Accounting Pronouncements

From time to time, new accounting pronouncements are issued by FASB that are adopted by the Company as of the specified effective date. If not discussed, management believes that the impact of recently issued standards, which are not yet effective, will not have a material impact on the Company's financial statements upon adoption. There have been no developments to recently issued accounting standards, including the expected dates of adoption and estimated effects on our financial statements, from those disclosed in our Annual Report on Form 10-K for the year ended December 31, 2011.

Presentation of Comprehensive Income

In June 2011, the FASB issued Comprehensive Income (Topic 220) — Presentation of Comprehensive Income (ASU No. 2011-05). The guidance eliminates the option of presenting components of other comprehensive income as part of the statement of stockholders' equity. The standard will allow the Company the option to present the total of comprehensive income, the components of net income and the components of other comprehensive income in either a single continuous statement of comprehensive income or in two separate but consecutive statements. In December 2011, the FASB issued Comprehensive Income (Topic 220) — Deferral of the Effective Date for Amendments to the Presentation of Reclassifications of Items Out of Accumulated Other Comprehensive Income in Accounting Standards Update No. 2011-05 (ASU No. 2011-12). The FASB indefinitely deferred the effective date for the guidance related to the presentation of reclassifications of items out of accumulated other comprehensive income by component in both the statement in which net income is presented and the statement in which other comprehensive income is presented. The standard, except for the portion that was indefinitely deferred, is effective for the Company on January 1, 2012, and must be applied retrospectively. On January 1, 2012, the Company adopted this standard on disclosure and it did not impact the Company's results of operations, financial position or cash flows.

Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs

In May 2011, the FASB issued Fair Value Measurement (Topic 820) — Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS (ASU No. 2011-04). The standard generally clarifies the application of existing requirements on topics including the concepts of highest and best use and valuation premise and disclosing quantitative information about the unobservable inputs used in the measurement of instruments categorized within Level 3 of the fair value hierarchy. Additionally, the standard includes changes on topics such as measuring fair value of financial instruments that are managed within a portfolio and additional disclosure for fair value measurements categorized within Level 3 of the fair value hierarchy. This standard is effective for the Company on January 1, 2012. The standard will require additional disclosures, but it will not impact the Company's results of operations, financial position or cash flows. On January 1, 2012, the Company adopted this standard on disclosure and it did not impact the Company's results of operations, financial position or cash flows.

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NOTE 3   CRUDE OIL AND NATURAL GAS PROPERTIES

The value of the Company's crude oil and natural gas properties consists of all acreage acquisition costs (including cash expenditures and the value of stock consideration), drilling costs and other associated capitalized costs. Acquisitions are accounted for as purchases and, accordingly, the results of operations are included in the accompanying statements of income and comprehensive income from the closing date of the acquisition. Purchase prices are allocated to acquired assets based on their estimated fair value at the time of the acquisition. In the past, acquisitions have been funded with internal cash flow, bank and other borrowings and the issuance of equity securities. At September 30, 2012, approximately $118.9 million of capital expenditures were in accounts payable.

Acquisitions

For the nine months ended September 30, 2012, the Company acquired or earned through farm-in arrangements approximately 21,153 net acres, for an average cost of approximately $1,913 per net acre, in its key prospect areas in the form of effective leases.

For the nine months ended September 30, 2011, the Company acquired approximately 30,600 net acres, for an average cost of $1,820 per net acre, in its key prospect areas in the form of effective leases.

Unproved Properties

At September 30, 2012 and December 31, 2011, the amount of capitalized costs excluded from depletion was $104.9 million and $137.8 million, respectively. The Company believes that the majority of its unproved costs will become subject to depletion within the next five years by proving up reserves relating to the acreage through exploration and development activities, by impairing the acreage that will expire before the Company can explore or develop it further or by determining that further exploration and development activity will not occur. The timing by which all other properties will become subject to depletion will be dependent upon the timing of future drilling activities and delineation of its reserves.

Excluded costs for unproved properties are accumulated by year. Costs are reflected in the full cost pool as the drilling costs are incurred or as costs are evaluated and deemed impaired. The Company anticipates these excluded costs will be included in the depletion computation over the next five years. The Company is unable to predict the future impact on depletion rates.

The Company had 153 gross (10.1 net) wells drilling, awaiting completion or completing as of September 30, 2012. All properties that are not classified as proven properties are considered unproved properties and, thus, the costs associated with such properties are not subject to depletion. Once a property is classified as proven, all associated acreage and drilling costs are subject to depletion.

The Company historically has acquired its properties by purchasing individual or small groups of leases directly from mineral owners or from landmen or lease brokers, which leases historically have not been subject to specified drilling projects, and by purchasing lease packages in identified project areas controlled by specific operators. The Company generally participates in drilling activities by electing whether to participate in each well on a well-by-well basis at the time wells are proposed for drilling, with the exception of the defined drilling projects with Slawson Exploration Company, Inc. ("Slawson") described below.

As of September 30, 2012, the Company was participating in three defined drilling projects with Slawson, with participation interests ranging between 4.5% and 50% covering an aggregate of approximately 19,556 net acres of leasehold interests held by the Company. The areas cover the Windsor project area (4.5% participation interest) which includes approximately 2,722 net acres held by the Company, primarily located in Mountrail and surrounding counties of North Dakota. The South West Big Sky project (20% participation interest) includes approximately 5,216 net acres held by the Company in Richland County, Montana. The Lambert project (50% participation interest) includes approximately 11,618 net acres held by the Company in Richland and Dawson Counties, Montana.

NOTE 4 LONG-TERM DEBT

Revolving Credit Facility

In February, 2012, the Company entered into an amended and restated credit agreement providing for a revolving credit facility (the "Revolving Credit Facility"), which replaced its previous bank credit facility with a syndicated facility. The Revolving Credit Facility, which is secured by substantially all of the Company's assets, provides for a commitment equal to the lesser of the facility amount or the borrowing base. At September 30, 2012, the facility amount was $750 million, the borrowing base was $350 million and there was a $68.0 million outstanding balance, leaving $282 million of borrowing capacity available under the facility. Under the terms of the Revolving Credit Facility, the Company is limited to $500 million of permitted additional indebtedness, as defined, provided that the borrowing base will be reduced by 25% of the stated amount of any such permitted additional indebtedness. The $300 million in Notes described below is "permitted additional indebtedness" as defined in the Revolving Credit Facility.

The Revolving Credit Facility matures on January 1, 2017 and provides for a borrowing base subject to redetermination semi-annually each April and October and for event-driven unscheduled redeterminations. Borrowings under the Revolving Credit Facility can either be at the Alternate Base Rate (as defined) plus a spread ranging from 0.75% to 1.75% or LIBOR borrowings at the Adjusted LIBO Rate (as defined) plus a spread ranging from 1.75% to 2.75%. The applicable spread is dependent upon borrowings relative to the borrowing base. The Company may elect, from time to time, to convert all or any part of its LIBOR loans to base rate loans or to convert all or any of the base rate loans to LIBOR loans. A commitment fee is paid on the undrawn balance based on an annual rate of 0.375% to 0.50%. At September 30, 2012, the commitment fee was 0.375% and the interest rate margin was 1.75% on LIBOR loans and 0.75% on base rate loans.

The Revolving Credit Facility contains negative covenants that limit the Company's ability, among other things, to pay any cash dividends, incur additional indebtedness, sell assets, enter into certain hedging contracts, change the nature of its business or operations, merge, consolidate, or make investments. In addition, the Company is required to maintain a ratio of debt to EBITDAX (as defined in the credit agreement) of no greater than 4.0 to 1.0, maintain a ratio of EBITDAX to interest expense (as defined in the credit agreement) of not less that 3.0 to 1.0 and a current ratio (as defined in the credit agreement) of no less than 1.0 to 1.0. The Company was in compliance with its covenants under the Revolving Credit Facility at September 30, 2012.

All of the Company's obligations under the Revolving Credit Facility are secured by a first priority security interest in any and all assets of the Company.

8.000% Senior Notes Due 2020

On May 18, 2012, the Company issued $300 million aggregate principal amount of 8.000% senior unsecured notes due June 1, 2020 (the "Notes"). Interest is payable on the Notes semi-annually in arrears on each of June 1 and December 1, commencing December 1, 2012. The Company currently does not have any subsidiaries and, as a result, the Notes will not be guaranteed initially. Any subsidiaries the Company forms in the future may be required to unconditionally guarantee, jointly and severally, payment obligation under the Notes on a senior unsecured basis. The issuance of these Notes resulted in net proceeds to the Company of approximately $291.2 million, which are in use to fund the Company's exploration, development and acquisition program and for general corporate purposes (including repayment of borrowings that were outstanding under the Revolving Credit Facility at the time the Notes were issued).

At any time prior to June 1, 2015, the Company may redeem up to 35% of the Notes at a redemption price of 108% of the principal amount, plus accrued and unpaid interest to the redemption date, with the proceeds of certain equity offerings, so long as the redemption occurs within 180 days of completing such equity offering and at least 65% of the aggregate principal amount of the Notes remains outstanding after such redemption. Prior to June 1, 2016, the Company may redeem some or all of the Notes for cash at a redemption price equal to 100% of their principal amount plus an applicable make-whole premium and accrued and unpaid interest to the redemption date. On and after June 1, 2016, the Company may redeem some or all of the Notes at redemption prices (expressed as percentages of principal amount) equal to 104% for the twelve-month period beginning on June 1, 2016, 102% for the twelve-month period beginning June 1, 2017 and 100% beginning on June 1, 2018, plus accrued and unpaid interest to the redemption date.

On May 18, 2012, in connection with the issuance of the Notes, the Company entered into an Indenture (the "Base Indenture"), by and among the Company and Wilmington Trust, National Association, as trustee (the "Trustee"). The Indenture restricts the Company's ability to: (i) incur additional debt or enter into sale and leaseback transactions; (ii) pay distributions on, redeem or, repurchase equity interests; (iii) make certain investments; (iv) incur liens; (v) enter into transactions with affiliates; (vi) merge or consolidate with another company; and (vii) transfer and sell assets. These covenants are subject to a number of important exceptions and qualifications. If at any time when the Notes are rated investment grade by both Moody's Investors Service, Inc. and Standard & Poor's Ratings Services and no Default (as defined in the Indenture) has occurred and is continuing, many of such covenants will terminate and the Company and its subsidiaries (if any) will cease to be subject to such covenants.

The Indenture contains customary events of default, including:

- default in any payment of interest on any Note when due, continued for 30 days;
- default in the payment of principal of or premium, if any, on any Note when due;
- failure by the Company to comply with its other obligations under the Indenture, in certain cases subject to notice and grace periods;
- payment defaults and accelerations with respect to other indebtedness of the Company and its Restricted Subsidiaries (as defined in the Indenture) in the aggregate principal amount of $25 million or more;
- certain events of bankruptcy, insolvency or reorganization of the Company or a Significant Subsidiary (as defined in the Indenture) or group of Restricted Subsidiaries that, taken together, would constitute a Significant Subsidiary;
- failure by the Company or any Significant Subsidiary or group of Restricted Subsidiaries that, taken together, would constitute a Significant Subsidiary to pay certain final judgments aggregating in excess of $25 million within 60 days; and
- any guarantee of the Notes by a Guarantor ceases to be in full force and effect, is declared null and void in a judicial proceeding or is denied or disaffirmed by its maker.

NOTE 5 COMMON AND PREFERRED STOCK

The Company's Articles of Incorporation authorize the issuance of up to 100,000,000 shares. The shares are classified in two classes, consisting of 95,000,000 shares of common stock, par value $.001 per share, and 5,000,000 shares of preferred stock, par value $.001 per share. The board of directors is authorized to establish one or more series of preferred stock, setting forth the designation of each such series, and fixing the relative rights and preferences of each such series. The Company has neither designated nor issued any shares of preferred stock.

Common Stock

The following is a schedule of changes in the number of common stock during the nine months ended September 30, 2012 and the year ended December 31, 2011:

	Nine Months	Year Ended

	Ended September 30, 2012	December 31, 2011
Beginning balance	63,330,421	62,129,424
Stock options exercised	10,500	3,500
Restricted stock grants (Note 6)	825,436	947,891
Warrants exercised	-	300,000
Other Surrenders	(675,690)	(50,394)
Ending balance	63,490,667	63,330,421

2012 Activity

In each of January 2012, April 2012 and July 2012, a director of the Company exercised 3,500 shares of stock options granted to him in 2007.

In January 2012, 47,140 shares of common stock were surrendered by certain executives of the Company to cover tax obligations in connection with their restricted stock awards. The total value of these shares was approximately $1.2 million, which was based on the market price on the date the shares were surrendered.

During 2012, the Company's compensation committee of the board of directors adopted a bonus plan that includes a matrix of performance goals that will be used to determine 2012 bonuses for executive officers. For 2012, the annual performance goals will include metrics related to production, Adjusted EBITDA, acreage position, acreage development, stock performance and specified milestones relating to the successful execution of the Company's business plan and completion of key projects.

For the nine month period ended September 30, 2012, the Company had accrued bonuses of approximately $2.7 million based on the year to date results of operations in comparison to year-end bonus performance goals. During the three and nine months ended September 30, 2012, the Company expensed approximately $578,000 and $1,378,000, respectively, in compensation related to this bonus accrual and capitalized the remaining into the full cost pool. The Company had accrued bonuses of approximately $2.9 million for the nine months ended September 30, 2011, approximately $485,000 and $900,000 were expensed in share-based compensation for the three and nine months ended September 30, 2011, respectively, and capitalized the remaining into the full cost pool

NOTE 6 STOCK OPTIONS/STOCK-BASED COMPENSATION AND WARRANTS

On April 26, 2011, the board of directors approved an amendment and restatement of the Northern Oil and Gas, Inc. 2009 Equity Incentive Plan (the "Plan"), which was approved at the annual meeting of shareholders. An additional 1,000,000 shares were authorized for grant under the Plan, resulting in an aggregate of 4,000,000 shares authorized for past and future grants under the Plan. The Plan is intended to provide a means whereby the Company may be able, by granting stock options and shares of restricted stock, to attract, retain and motivate capable and loyal employees, non-employee directors, consultants and advisors of the Company, for the benefit of the Company and its shareholders.

Restricted Stock Awards

During the nine months ended September 30, 2012, the Company issued 825,436 restricted shares of common stock as compensation to officers and employees of the Company. Unvested restricted shares vest over various terms with all restricted shares vesting no later than June 2016. As of September 30, 2012, there was approximately $7.4 million of total unrecognized compensation expense related to unvested restricted stock. This compensation expense will be recognized over the remaining vesting period of the grants. The Company has assumed a zero percent forfeiture rate for restricted stock due to the small number of officers and employees that have received restricted stock awards.

The following table reflects the outstanding restricted stock awards and activity related thereto for the nine months ended September 30, 2012:

	Nine Months Ended September 30, 2012

	Number of Shares	Weighted-Average Price
Restricted Stock Awards:		
Restricted Shares Outstanding at the Beginning of Period	1,216,992	$19.87
Shares Granted	825,436	20.59
Shares Forfeited	(628,550)	19.08
Lapse of Restrictions	(526,792)	22.42
Restricted Shares Outstanding at September 30, 2012	887,086	$19.60

Stock Option Awards

On November 1, 2007, the board of directors granted options to purchase 560,000 shares of the Company's common stock under the Company's 2006 Incentive Stock Option Plan. The Company granted options to purchase 500,000 shares of the Company's common stock, to members of the board and options to purchase 60,000 shares of the Company's common stock to one employee pursuant to an employment agreement. These options were granted at a price of $5.18 per share and the optionees were fully vested on the grant date. As of September 30, 2012, options to purchase a total of 251,963 shares remain outstanding but unexercised. The board of directors determined that no future grants will be made pursuant to the 2006 Incentive Stock Option Plan. All future stock compensation will be issued under the 2009 Equity Incentive Plan.

The Company used the Black-Scholes option valuation model to calculate stock-based compensation at the date of grant. Option pricing models require the input of highly subjective assumptions, including the expected price volatility. Changes in these assumptions can materially affect the fair value estimate. The total fair value of the options is recognized as compensation over the vesting period. There have been no stock options granted in the nine months ended September 30, 2012 under the 2006 Stock Option Plan or the 2009 Equity Incentive Plan. All exercises of options as of September 30, 2012 relate to the 2007 grants.

Currently Outstanding Options

- No options were forfeited in the nine month period ended September 30, 2012.
- No options expired during the nine month period ended September 30, 2012.
- Options covering 251,963 shares were exercisable and outstanding at September 30, 2012.
- There is no further compensation expense that will be recognized in future periods relative to any options that had been granted as of September 30, 2012, because the Company recognized the entire fair value of such compensation upon vesting of the options.
- 3,500 options were exercised in the three months ended September 30, 2012 and an aggregate of 10,500 options were exercised in the nine months ended September 30, 2012.
- There were no unvested options at September 30, 2012.

NOTE 7 RELATED PARTY TRANSACTIONS

Carter Stewart, a former director of the Company (until August 2011), owned a 25% interest in Gallatin Resources, LLC ("Gallatin"). Legal counsel for Gallatin informed the Company that Mr. Stewart did not have the power to control Gallatin because each member of Gallatin has the right to vote on matters in proportion to their respective membership interest in the company and company matters are determined by a vote of the holders of a majority of membership interests. Further, Mr. Stewart was neither an officer nor a director of Gallatin. As such, Mr. Stewart did not have the ability to individually control company decisions for Gallatin. In 2011, the Company paid Gallatin a total of approximately $6,500 related to previously acquired leasehold interests. During the nine month period ended September 30, 2012, the Company paid Gallatin a total of approximately $500 related to previously acquired leasehold interests.

All transactions involving related parties were approved by the Company's board of directors or Audit Committee.

NOTE 8 COMMITMENTS & CONTINGENCIES

Litigation

The Company is engaged in proceedings incidental to the normal course of business. Due to their nature, such legal proceedings involve inherent uncertainties, including but not limited to, court rulings, negotiations between affected parties and governmental intervention. Based upon the information available to the Company and discussions with legal counsel, it is the Company's opinion that the outcome of the various legal actions and claims that are incidental to its business will not have a material impact on the financial position, results of operations or cash flows. Such matters, however, are subject to many uncertainties, and the outcome of any matter is not predictable with assurance.

The Company is party to a quiet title action in North Dakota that relates to its interest in certain oil and natural gas leases. In the event the action results in a final judgment that is adverse to the Company, the Company would be required to reverse approximately $1.2 million in revenue (net of accrued taxes) that has been accrued since the second quarter of 2008 based on the Company's purported interest in the oil and gas leases at issue, $5,000 and $87,000 of which relates to the three and nine month periods ended September 30, 2012, respectively. The Company fully maintains the validity of its interest in the oil and natural gas leases, and is vigorously defending such interest.

NOTE 9 INCOME TAXES

The Company utilizes the asset and liability approach to measuring deferred tax assets and liabilities based on temporary differences existing at each balance sheet date using currently enacted tax rates. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized. Deferred tax assets and liabilities are adjusted for the effects of changes in tax laws and rates on the date of enactment.

The income tax provision for the three and nine months ended September 30, 2012 and 2011 consists of the following:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Current Income Taxes	$3,422	$-	$8,772	$2,300
Deferred Income Taxes				
Federal	175,000	14,798,000	30,660,000	21,813,000
State	35,000	2,375,000	4,210,000	3,910,000
Total Provision	$213,422	$17,173,000	$34,878,772	$25,725,300

Tax benefits are recognized only for tax positions that are more likely than not to be sustained upon examination by tax authorities. The amount recognized is measured as the largest amount of benefit that is greater than 50 percent likely to be realized upon ultimate settlement. Unrecognized tax benefits are tax benefits claimed in the Company's tax returns that do not meet these recognition and measurement standards.

The Company has no liabilities for unrecognized tax benefits.

The Company's policy is to recognize potential interest and penalties accrued related to unrecognized tax benefits within income tax expense. For the three and nine months ended September 30, 2012 and 2011, the Company did not recognize any interest or penalties in its statements of income and comprehensive income , nor did it have any interest or penalties accrued in its balance sheet at September 30, 2012 and December 31, 2011 relating to unrecognized benefits.

The tax years 2011, 2010, and 2009 remain open to examination for federal income tax purposes and by the other major taxing jurisdictions to which the Company is subject. During 2012, the IRS commenced an examination of the Company's 2009 tax return. No adjustments to prior tax returns or additional tax obligations have been identified to date in the examination.

NOTE 10 FAIR VALUE

Fair value is defined as the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants on the measurement date. Valuation techniques used to measure fair value must maximize the use of observable inputs and minimize the use of unobservable inputs. The Company uses a fair value hierarchy based on three levels of inputs, of which the first two are considered observable and the last unobservable, that may be used to measure fair value which are the following:

Level 1 - Quoted prices in active markets for identical assets or liabilities.

Level 2 - Inputs other than Level 1 that are observable, either directly or indirectly, such as quoted prices for similar assets of liabilities; quoted prices in markets that are not active; or other inputs that are observable or can be corroborated by observable market data for substantially the full term of the assets or liabilities.

Level 3 - Unobservable inputs that are supported by little or no market activity and that are significant to the fair value of the assets or liabilities.

The following schedule summarizes the valuation of financial instruments measured at fair value on a recurring basis in the balance sheet as of September 30, 2012 and December 31, 2011.

	Fair Value Measurements at September 30, 2012 Using		
	Quoted Prices In Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Commodity Derivatives – Current Asset (crude oil swaps and collars)	$ -	$ 4,005,611	$ -
Commodity Derivatives – Non-Current Asset (crude oil swaps and collars)	-	2,283,655	-
Total	$ -	$ 6,289,266	$ -

	Fair Value Measurements at December 31, 2011 Using		
	Quoted Prices In Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Commodity Derivatives – Current Liability (crude oil swaps and collars)	$ -	$ (9,363,068)	$ -
Commodity Derivatives – Non-Current Liability (crude oil swaps and collars)	-	(2,574,903)	-
Total	$ -	$ (11,937,971)	$ -

Level 2 assets and liabilities consist of derivative assets and liabilities (see Note 12), the Revolving Credit Facility (see Note 4) and the Senior Notes (see Note 4). The fair value of the Company's derivative financial instruments is based upon futures prices, volatility and time to maturity, among other things. Counterparty statements are utilized to determine the value of the commodity derivative instruments and are reviewed and corroborated using various methodologies and significant observable inputs. The Company's and the counterparties' nonperformance risk is evaluated. The fair value of all derivative contracts is reflected on the balance sheet. The current derivative assets and liability amounts represent the fair values expected to be settled in the subsequent year. The book value of the Revolving Credit Facility approximates fair value because of its floating rate structure. The fair value of our 8% senior notes is based on an end of period market quote.

The Company’s long-term debt is not measured at fair value on the balance sheets and the fair value is being provided for disclosure purposes. At September 30, 2012, the Company had $300 million of senior unsecured notes and $68 million under the Revolving Credit Facility outstanding with a fair value of $310.5 million and $68 million, respectively. At December 31, 2011, the Company had $69.9 million outstanding under a revolving credit facility. The estimated fair value of debt was based upon quoted market prices and, where such prices were not available, other observable inputs regarding interest rates available to the Company at the end of each respective period.

Though the Company believes the methods used to estimate fair value are consistent with those used by other market participants, the use of other methods or assumptions could result in a different estimate of fair value. There were no transfers of financial assets or liabilities between Level 1 and Level 2 inputs for the nine month period ended September 30, 2012.

NOTE 11 FINANCIAL INSTRUMENTS

The Company’s non-derivative financial instruments include cash and cash equivalents, accounts receivable, and accounts payable and are not measured at fair value on the balance sheets. The carrying amount of these non-derivative financial instruments approximates their fair values.

The Company’s accounts receivable relate to crude oil and natural gas sold to various industry companies. Credit terms, typical of industry standards, are of a short-term nature and the Company does not require collateral. Management believes the Company’s accounts receivable at September 30, 2012 and December 31, 2011 do not represent significant credit risks as they are dispersed across many counterparties. The Company has determined that no allowance for doubtful accounts is necessary at September 30, 2012 and December 31, 2011. As of September 30, 2012, outstanding derivative contracts with commercial banks participating in the Revolving Credit Facility represent all of the Company’s crude oil volumes hedged. These commercial banks have investment-grade ratings from Moody’s and Standard & Poor and are lenders under the Revolving Credit Facility and management believes this does not represent a significant credit risk.

NOTE 12 DERIVATIVE INSTRUMENTS AND PRICE RISK MANAGEMENT

The Company utilizes commodity swap contracts and costless collars (purchased put options and written call options) to (i) reduce the effects of volatility in price changes on the crude oil commodities it produces and sells, (ii) reduce commodity price risk and (iii) provide a base level of cash flow in order to assure it can execute at least a portion of its capital spending.

On November 1, 2009, due to the volatility of price differentials in the Williston Basin, the Company de-designated all derivatives that were previously classified as cash flow hedges and, in addition, the Company has elected not to designate any subsequent derivative contracts as cash flow hedges. Beginning on November 1, 2009, all derivative positions are carried at their fair value on the balance sheet and are marked-to-market at the end of each period. Any realized gains and losses are recorded to gain (loss) on settled derivatives and unrealized mark-to-market gains or losses are recorded to gain (loss) on derivative instruments on the statement of income and comprehensive income rather than as a component of other comprehensive income (loss) or other income (expense).

Crude Oil Derivative Contracts Cash-flow Hedges

Prior to November 1, 2009, all derivative positions that qualified for hedge accounting were designated on the date the Company entered into the contract as a hedge against the variability in cash flows associated with the forecasted sale of future crude oil production. The cash flow hedges were valued at the end of each period and adjustments to the fair value of the contract prior to settlement were recorded on the statement of stockholders’ equity as other comprehensive income. Upon settlement, the gain (loss) on the cash flow hedge was recorded as an increase or decrease in revenue on the statement of income and comprehensive income. The Company reports average crude oil and natural gas prices and revenues including the net results of hedging activities.

The net loss on the Company’s remaining swaps that qualified for cash flow hedge accounting at the date the decision was made to discontinue hedge accounting totals approximately $0 and $101,000 as of September 30, 2012 and December 31, 2011, respectively. The Company has recorded that amount as accumulated other comprehensive income in stockholders’ equity and the entire amount was amortized into revenues as the original forecasted hedged crude oil production occurred.

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Crude Oil Derivative Contracts Cash-flow Not Designated as Hedges

The Company had a realized gain (loss) on settled derivatives of $1,701,296 and ($1,824,719) for the three months ended September 30, 2012 and 2011, respectively. The Company had an unrealized (loss) gain on derivative instruments of ($22,308,470) and $27,105,400 for the three months ended September 30, 2012 and 2011, respectively. The Company had a realized loss on settled derivatives of $4,729,186 and $10,695,006 for the nine months ended September 30, 2012 and 2011, respectively. The Company had an unrealized gain on derivative instruments of $18,125,928 and $26,675,003 for the nine months ended September 30, 2012 and 2011, respectively.

The following table reflects open commodity swap contracts as of September 30, 2012, the associated volumes and the corresponding weighted average NYMEX reference price.

Settlement Period	Oil (Barrels)	Fixed Price	Weighted Avg NYMEX Reference Price
Oil Swaps			
10/01/12 – 12/31/12	60,000	$90.40	$92.73
10/01/12 – 12/31/14	540,000	91.65	92.61
10/01/12 – 12/31/12	60,000	97.80	92.21
10/01/12 – 12/31/12	30,000	104.50	92.75
10/01/12 – 12/31/12	150,000	88.00	92.73
10/01/12 – 12/31/12	142,500	95.15	92.72
10/01/12 – 12/31/12	60,000	100.00	92.74
01/01/13 – 12/31/13	300,000	89.50	93.61
01/01/13 – 12/31/13	240,000	91.10	93.70
07/01/13 – 12/31/13	60,000	102.30	93.51
01/01/14 – 6/30/14	300,000	89.50	92.03
01/01/14 – 6/30/14	240,000	90.00	92.44
01/01/14 – 12/31/14	240,000	90.15	91.49
01/01/14 – 12/31/14	240,000	91.00	91.49
01/01/14 – 06/30/14	240,000	100.00	92.46
07/01/14 – 12/31/14	120,000	90.00	90.87
07/01/14 – 12/31/14	120,000	93.50	90.90

As of September 30, 2012, the Company had a total volume on open commodity swaps of 3,142,500 barrels at a weighted average price of approximately $92.12.

In addition to the open commodity swap contracts the Company has entered into costless collars. The costless collars are used to establish floor and ceiling prices on anticipated crude oil production. There were no premiums paid or received by the Company related to the costless collar agreements. The following table reflects open costless collar agreements as of September 30, 2012.

Term	Oil (Barrels)		Price	Basis
Costless Collars				
10/01/12 – 12/31/12	60,000	$	90.00/$98.50	NYMEX

10/01/12 – 12/31/12	33,308	$	85.00/$95.25	NYMEX
10/01/12 – 12/31/12	60,000	$	95.00/$115.10	NYMEX
10/01/12 – 12/31/13	199,026	$	90.00/$103.50	NYMEX
10/01/12 – 12/31/13	188,018	$	90.00/$106.50	NYMEX
10/01/12 – 12/31/13	292,580	$	90.00/$110.00	NYMEX
10/01/12 – 12/31/13	247,683	$	95.00/$107.00	NYMEX
01/01/13 – 12/31/13	480,000	$	95.00/$110.70	NYMEX
01/01/13 – 12/31/13	760,794	$	85.00/$98.00	NYMEX
07/01/13 – 12/31/13	96,000	$	95.00/$106.90	NYMEX
01/01/14 – 12/31/14	240,000	$	90.00/$99.05	NYMEX

At September 30, 2012 and December 31, 2011, the Company had derivative financial instruments recorded on the balance sheet as set forth below:

Type of Contract	Balance Sheet Location	September 30, 2012 Estimated Fair Value	December 31, 2011 Estimated Fair Value
Derivative Assets:			
Swap Contracts	Current assets/liabilities	$ 1,733,586	$ 285,126
Swap Contracts	Non-current assets	2,502,317	-
Costless Collars	Current assets/liabilities	12,395,866	1,932,884
Costless Collars	Non-current asset/liabilities	7,615,509	8,766,484
Total Derivative Assets		$ 24,247,278	$ 10,984,494
Derivative Liabilities:			
Swap Contracts	Current assets/liabilities	$ (2,592,475)	$ (8,383,588)
Swap Contracts	Non-current assets	(2,635,325)	-
Costless Collars	Current assets/liabilities	(7,531,366)	(3,197,490)
Costless Collars	Non-current assets/liabilities	(5,198,846)	(11,341,387)
Total Derivative Liabilities		$ (17,958,012)	$ (22,922,465)

The following disclosures are applicable to the Company's financial statements, as of September 30, 2012 and 2011:

Derivative Type	Location of Loss for Effective and Ineffective Portion of Derivative In Income	Amount of Loss Reclassified from AOCI into Income — Three Months Ended September 30, 2012	2011	2012
Commodity - Cash Flow	Loss on Settled Derivatives	$ -	$ 295,950	$ 101,309

The use of derivative transactions involves the risk that the counterparties will be unable to meet the financial terms of such transactions. In some cases, the Company has netting arrangements with its counterparties that provide for offsetting payables against receivables from separate derivative instruments.

NOTE 13 SEVERANCE ARRANGEMENT

In connection with the resignation of its former president, the Company and Mr. Gilbertson entered into a separation and release agreement and a consulting agreement (collectively, the "New Agreements"), which terminate and supersede his prior employment agreement with the Company (except for certain surviving provisions). Pursuant to the New Agreements, Mr. Gilbertson's outstanding and unvested restricted stock awards will continue to vest on their original vesting schedules, so long as Mr. Gilbertson does not terminate the consulting agreement and the Company does not terminate the consulting agreement for cause (as defined). In addition, pursuant to the New Agreements the Company will (i) provide Mr. Gilbertson with a prorated portion of his 2012 year-end bonus (based on predetermined performance metrics and as determined by the Company's compensation committee following the end of 2012), (ii) buy out the lease and transfer title to Mr. Gilbertson on his Company-leased vehicle, and (iii) reimburse Mr. Gilbertson for continuation coverage pursuant to COBRA on the Company's health plans for up to 18 months.

In connection with the New Agreements, the Company concluded the unvested restricted stock awards were modified in connection with the change in Mr. Gilbertson's employment status and service requirements. Because the Company expects Mr. Gilbertson's awards will vest under the modified conditions but his period of active service in substance has concluded, $4.3 million of share based compensation costs was reflected in general and administrative expense during the third quarter of 2012 related to the modified awards. Additionally, the cash expenses estimated for Mr. Gilbertson's prorated 2012 bonus, Company-leased vehicle and continuation coverage pursuant to COBRA was estimated at approximately $0.6 million and was reflected in general and administrative expense during the third quarter of 2012.

NOTE 14 SUBSEQUENT EVENTS

In connection with preparing the unaudited financial statements for the nine months ended September 30, 2012, the Company has evaluated subsequent events for potential recognition and disclosure through the date of this filing and determined that, except as noted below in this Note 14, there were no subsequent events which required recognition or disclosure in the financial statements.

On October 16, 2012, the Company terminated the employment of its Chief Operating Officer, James R. Sankovitz. Mr. Sankovitz's termination was "not for cause" under his existing employment agreement with the Company, and as a result he will be entitled to certain severance benefits which includes a single lump-sum payment of one times his $325,000 base salary. In addition, the Company has agreed to buy out the lease and transfer title to Mr. Sankovitz on his Company-leased vehicle, and reimburse Mr. Sankovitz for continuation coverage pursuant to COBRA on the Company's health plans for up to 18 months.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations.

Cautionary Statement Concerning Forward-Looking Statements

This Management's Discussion and Analysis of Financial Condition and Results of Operations contains forward-looking statements regarding future events and our future results that are subject to the safe harbors created under the Securities Act of 1933 (the "Securities Act") and the Securities Exchange Act of 1934 (the "Exchange Act"). All statements other than statements of historical facts included in this report regarding our financial position, business strategy, plans and objectives of management for future operations, industry conditions, and indebtedness covenant compliance are forward-looking statements. When used in this report, forward-looking statements are generally accompanied by terms or phrases such as "estimate," "project," "predict," "believe," "expect," "anticipate," "target "intend," "seek," "goal," "will," "should," "may" or other words and similar expressions that convey the uncertainty of f events or outcomes. Items contemplating or making assumptions about actual or potential future sales, market size, collaborations, and trends or operating results also constitute such forward-looking statements.

Forward-looking statements involve inherent risks and uncertainties, and important factors (many of which are beyond our Company's control) that could cause actual results to differ materially from those set forth in the forward-looking statements, including the following: crude oil and natural gas prices, our ability to raise or access capital, general economic or industry conditions, nationally and/or in the communities in which our Company conducts business, changes in the interest rate environment, legislation or regulatory requirements, conditions of the securities markets, changes in accounting principles, policies or guidelines, financial or political instability, acts of war or terrorism, and other economic, competitive, governmental, regulatory and technical factors affecting our Company's operations, products and prices.

We have based any forward-looking statements on our current expectations and assumptions about future events. While our management considers these expectations and assumptions to be reasonable, they are inherently subject to significant business, economic, competitive, regulatory and other risks, contingencies and uncertainties, most of which are difficult to predict and many of which are beyond our control. Accordingly, results actually achieved may differ materially from expected results described in these statements. Forward-looking statements speak only as of the date they are made. You should consider carefully the statements in the section entitled "Item 1A. Risk Factors" and other sections of our Annual Report on Form 10-K for the fiscal year ended December 31, 2011, as updated by subsequent reports we file with the SEC (including this report and our reports on Form 10-Q for the fiscal quarters ended March 31, 2012 and June 30, 2012), which describe factors that could cause our actual results to differ from those set forth in the forward-looking statements. Our Company does not undertake, and specifically disclaims, any obligation to update any forward-looking statements to reflect events or circumstances occurring after the date of such statements.

The following discussion should be read in conjunction with the Financial Statements and Accompanying Notes appearing elsewhere in this report.

Overview

We are an independent energy company engaged in the acquisition, exploration, development and production of oil and natural gas properties, with operations in North Dakota and Montana that primarily target the Bakken and Three Forks formations in the Williston Basin of the United States. We believe the location, size and concentration of our acreage position in one of North America's leading unconventional oil-resource plays will provide drilling and development opportunities that result in significant long-term value. Our primary focus is oil exploration and production through non-operated working interests in wells drilled and completed in spacing units that include our acreage.

As of December 31, 2011, our proved reserves were 46.8 MMBoe (all of which were in the Williston Basin) as estimated by Ryder Scott, our independent reservoir engineering firm, representing a 198% growth in proved reserves compared to year end 2010. As of December 31, 2011, 34% of our reserves were classified as proved developed and 89% of our reserves were oil.

Our average daily production in the third quarter of 2012 was approximately 11,282 Boe per day, of which approximately 92% was oil. Our third quarter 2012 average daily production increased 96% compared to an average of 5,743 Boe per day in the third quarter of 2011. As of September 30, 2012, we participated in 1,104 gross (98.5 net) producing wells.

As of September 30, 2012, we leased approximately 718,391 gross (183,788 net) acres, of which 100% were located in the Williston Basin of North Dakota and Montana. In 2011, we acquired approximately 43,239 net acres at an average cost of approximately $1,832 per net acre. During the nine months ended September 30, 2012, we acquired or earned through farm-in arrangements approximately 21,153 net acres at an average cost of approximately $1,913 per net acre.

Highlights from the First Nine Months of 2012 Results

During the nine month period ended September 30, 2012, we achieved the following financial and operating results:

- Including the effect of realized gains and losses from derivative contracts, oil, natural gas and NGL sales increased 121% for the nine month period ended September 30, 2012 as compared to the same period last year;
- Average daily production reached 10,075 Boe per day for the nine months ended September 30, 2012;
- Our developed well total increased to 1,104 gross (98.5 net) as of September 30, 2012;
- We entered into additional derivative contracts for 2012, 2013 and 2014;
- The borrowing base under our Revolving Credit Facility was increased from $120 million to $350 million; and
- We issued $300 million aggregate principal amount of 8.000% senior notes due 2020.

Total oil, natural gas, and NGL production increased 115% for the first nine months of 2012 compared to the same period in 2011. This increase was due to higher production levels resulting from 40.6 net wells added to production during the first nine months of 2012. Our average realized prices on a per Boe basis (including realized gains and losses from derivative contracts) were 3% higher during the first nine months of 2012 compared to the same period in 2011.

Source of Our Revenues

We derive our revenues from the sale of oil, natural gas and NGLs produced from our properties. Revenues are a function of the volume produced, the prevailing market price at the time of sale, oil quality, Btu content and transportation costs to market. We use derivative instruments to hedge future sales prices on a substantial, but varying, portion of our oil and natural gas production. We expect our derivative activities will help us achieve more predictable cash flows and reduce our exposure to downward price fluctuations. The use of derivative instruments has in the past, and may in the future, prevent us from realizing the full benefit of upward price movements but also mitigates the effects of declining price movements. Our average realized price calculations include the effects of the settlement of all derivative contracts regardless of the accounting treatment.

Principal Components of Our Cost Structure

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Oil price differentials. The price differential between our Williston Basin well head price and the NYMEX WTI benchmark price is driven by the additional cost to transport oil from the Williston Basin via train, barge, pipeline or truck to refineries.

- Unrealized gain (loss) on derivative instruments. We utilize commodity derivative financial instruments to reduce our exposure to fluctuations in the price of oil. This account activity represents the recognition of gains and losses associated with our outstanding derivative contracts as commodity prices and commodity derivative contracts change on contracts that have not been designated for hedge accounting.

- Realized gain (loss) on derivative instruments. This account activity represents our realized gains and losses on the settlement of commodity derivative instruments.

- Production expenses. Production expenses are daily costs incurred to bring oil and natural gas out of the ground and to the market, together with the daily costs incurred to maintain our producing properties. Such costs also include field personnel compensation, salt water disposal, utilities, maintenance, repairs and workover expenses related to our oil and natural gas properties.

- Production taxes. Production taxes are paid on produced oil and natural gas based on a percentage of revenues from products sold at market prices (not hedged prices) or at fixed rates established by federal, state or local taxing authorities. We seek to take full advantage of all credits and exemptions in our various taxing jurisdictions. In general, the production taxes we pay correlate to the changes in oil and natural gas revenues.

- Depreciation, depletion and amortization. Depreciation, depletion and amortization includes the systematic expensing of the capitalized costs incurred to acquire, explore and develop oil and natural gas. As a full cost company, we capitalize all costs associated with our development and acquisition efforts and allocate these costs to each unit of production using the units-of-production method.

- General and administrative expenses. General and administrative expenses include overhead, including payroll and benefits for our corporate staff, costs of maintaining our headquarters, costs of managing our acquisition and development operations, franchise taxes, audit and other professional fees and legal compliance.

- Interest expense. We finance a portion of our working capital requirements, capital expenditures and acquisitions with borrowings. As a result, we incur interest expense that is affected by both fluctuations in interest rates and our financing decisions. We capitalize a portion of the interest paid on applicable borrowings into our full cost pool. We include interest expense that is not capitalized into the full cost pool, the amortization of deferred financing costs (including origination and amendment fees), commitment fees and annual agency fees as interest expense.

- Income tax expense. Our provision for taxes includes both federal and state taxes. We record our federal income taxes in accordance with accounting for income taxes under GAAP which results in the recognition of deferred tax assets and liabilities for the expected future tax consequences of temporary differences between the book carrying amounts and the tax basis of assets and liabilities. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences and carryforwards are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized.

Selected Factors That Affect Our Operating Results

Our revenues, cash flows from operations and future growth depend substantially upon:

- the timing and success of drilling and production activities by our operating partners;
- the prices and demand for oil, natural gas and NGLs;
- the quantity of oil and natural gas production from the wells in which we participate;
- changes in the fair value of the derivative instruments we use to reduce our exposure to fluctuations in the price of oil;
- our ability to continue to identify and acquire high-quality acreage; and

- the level of our operating expenses.

In addition to the factors that affect companies in our industry generally, the location of our acreage and wells in the Williston Basin subjects our operating results to factors specific to this region. These factors include the potential adverse impact of weather on drilling, production and transportation activities, particularly during the winter months, and the limitations of the developing infrastructure and transportation capacity in this region.

The price of oil in the Williston Basin can vary depending on the market in which it is sold and the means of transportation used to transport the oil to market. Light sweet crude from the Williston Basin has a higher value at many major refining centers because of its higher quality relative to heavier and sour grades of crude oil; however, because of North Dakota's location relative to traditional oil transport centers, this higher value is generally offset to some extent by higher transportation costs. While rail transportation has historically been more expensive than pipeline transportation, Williston Basin prices have been high enough to justify shipment by rail to markets as far as St. James, Louisiana, which offers prices benchmarked to Brent/LLS. Although pipeline, truck and rail capacity in the Williston Basin has historically lagged production in growth, we believe that additional planned infrastructure growth will help keep price discounts from significantly eroding wellhead values in the region.

The price at which our oil production is sold typically reflects a discount to the NYMEX WTI benchmark price. Thus, our operating results are also affected by changes in the oil price differentials between the NYMEX WTI and the sales prices we receive for our oil production. Higher oil price differentials lowered our oil and gas sales during the first nine months of 2012. Relatively mild weather in North Dakota allowed production throughout the winter (increasing supply) while some refineries were down for routine maintenance (decreasing demand). This caused oil price differentials to increase for a short period during the first half of 2012, which have subsequently declined due to various rail projects coming online, refineries completing their seasonal maintenance and the reversal of the Seaway pipeline from Cushing, Oklahoma to the Gulf Coast. As the rail capacity continues to increase and planned Seaway pipeline expansions are completed, we believe the oil price differentials will return to historical levels. Our oil price differential to the NYMEX WTI benchmark price during the first nine months of 2012 was \$12.50 per barrel, as compared to \$6.93 per barrel in the first nine months of 2011. Our oil price differential to the NYMEX WTI benchmark price during the three month periods ended September 30, 2012 and 2011 were \$10.18 and \$4.91, respectively.

Another significant factor affecting our operating results is drilling costs. The cost of drilling wells has increased significantly over the past few years as rising oil prices have triggered increased drilling activity in the Williston Basin. Although individual components of the cost can vary depending on numerous factors such as the length of the horizontal lateral, the number of fracture stimulation stages, and the choice of proppant (sand or ceramic), the total cost of drilling and completing an oil well has increased. This increase is largely due to longer horizontal laterals and more fracture stimulation stages, but also higher demand for rigs and completion services throughout the region. In addition, because of the rapid growth in drilling, the availability of well completion services has been constrained, and many producers face a backlog of wells that are awaiting completion.

Market Conditions

Prices for various quantities of oil, natural gas, and NGLs that we produce significantly impact our revenues and cash flows. Commodity prices have been volatile in recent years. The following tables list average New York Mercantile Exchange ("NYMEX") prices for natural gas and crude oil for the three and nine months ended September 30, 2012 and 2011.

	Three Months Ended September 30,	
	2012	2011

Average NYMEX prices(a)		
Crude oil (per bbl)	$92.20	$89.54
Natural gas (per mcf)	$2.89	$4.05

(a)Based on average NYMEX closing prices.

	Nine Months Ended September 30,	
	2012	2011
Average NYMEX prices(a)		
Crude oil (per bbl)	$96.16	$95.47
Natural gas (per mcf)	$2.58	$4.21

(a) Based on average NYMEX closing prices.

Results of Operations for the three month periods ended September 30, 2012 and September 30, 2011

The following table sets forth selected operating data for the periods indicated.

	Three Months Ended September 30,		
	2012	2011	% Change
Net Production:			
Oil (Bbl)	954,831	491,646	94 %
Natural Gas (Mcf)	498,846	220,298	126
Total (Boe)	1,037,972	528,362	96
Net Sales:			
Oil Sales	$79,142,522	$42,135,529	88
Natural Gas Sales	1,547,779	1,545,090	-
Gain (Loss) on Settled Derivatives	1,701,296	(1,824,719)	193
Unrealized (Loss) Gain on Derivative Instruments	(22,308,470)	27,105,400	(182)
Other Revenue	12,486	88,738	(86)
Total Revenues	60,095,613	69,050,038	(13)
Average Sales Prices:			
Oil (per Bbl)	$82.89	$85.70	(3)
Effect of Gain (Loss) on Settled Derivatives on Average Price (per Bbl)	1.78	(3.71)	148
Oil Net of Settled Derivatives (per Bbl)	84.67	81.99	3
Natural Gas and other liquids (per Mcf)	3.10	7.01	(56)
Realized price on a Boe basis including all realized derivative settlements	79.38	79.22	-
Operating Expenses:			
Production Expenses	$8,734,636	$3,910,859	123
Production Taxes	8,092,843	4,261,407	90
General and Administrative Expense (Including Share Based Compensation)	9,467,711	4,073,988	132
General and Administrative Expense (Non-Cash Share Based Compensation)	6,998,765	2,188,900	220
Depletion of Oil and Gas Properties	27,952,585	10,749,384	160
Costs and Expenses (per Boe):			
Production Expenses	$8.42	$7.40	14
Production Taxes	7.80	8.07	(3)
General and Administrative Expense (Including Share Based Compensation)	9.12	7.71	18
General and Administrative Expense (Non-Cash Share Based Compensation)	6.74	4.14	63
Depletion of Oil and Gas Properties	26.93	20.34	32
Net Producing Wells at Period End	98.5	43.6	126

Oil and Natural Gas Sales

In the third quarter of 2012, oil, natural gas and NGL sales, including the effect of settled derivatives, increased 97% as compared to the third quarter of 2011, driven primarily by a 96% increase in production. Higher oil price differentials in the third quarter of 2012 lowered the average realized price in the third quarter of 2012 as compared to the same period in 2011. The oil price differential during the third quarter of 2012 was $10.18 per barrel, as compared to $4.91 per barrel in the third quarter of 2011.

As discussed above, our production continues to grow through drilling success as we place new wells into production and through additions from acquisitions, partially offset by the natural decline of our oil and natural gas sales from existing wells. During the third quarter of 2012, our average daily production volumes increased 96% as compared to the third quarter of 2011. The production increased primarily due to the addition of more net productive wells in 2012 as compared to 2011.

Derivative Instruments

For the third quarter of 2012, we realized a gain on settled derivatives of $1.7 million, compared to $1.8 million loss for the third quarter of 2011. Our average realized price (including all derivative settlements) received during the third quarter of 2012 was $79.38 per Boe compared to $79.22 per Boe in the third quarter of 2011, due to slightly higher average NYMEX prices in 2012. Our average realized price (including all derivative settlements) calculation includes all cash settlements for derivatives.

We had unrealized loss on derivative instruments of $22.3 million in the third quarter of 2012, compared to a $27.1 million gain in the third quarter of 2011. At September 30, 2012, all of our derivative contracts were recorded at their fair value, which was a net asset of $6.3 million, an increase of $18.2 million from the $11.9 million net liability recorded as of December 31, 2011.

Production Expenses

Production expenses were $8.7 million in the third quarter of 2012 compared to $3.9 million in the third quarter of 2011. We experience increases in operating expenses as we add new wells and maintain production from existing properties. On a per unit basis, production expenses increased from $7.40 per Boe in the third quarter of 2011 to $8.42 in the third quarter of 2012. This increase was due to a rise in workover expenses, as well as increased costs associated with salt water trucking and disposal during 2012 as compared to 2011. On an absolute dollar basis, our production expenses in the third quarter of 2012 were 123% higher when compared to the same quarter in 2011 due to a 96% increase in production levels, as well as higher water hauling and disposal costs.

Production Taxes

We pay production taxes based on realized oil and natural gas sales. These costs were $8.1 million in the third quarter of 2012 compared to $4.3 million in the third quarter of 2011. As a percent of oil and natural gas sales, our production taxes were 10.0% and 9.8% in the third quarter of 2012 and 2011, respectively. The third quarter of 2012 average production tax rate was higher than the third quarter of 2011 average due to greater levels of production from properties that did not qualify for reduced rates/or tax exemptions during 2012. A portion of our production is in Montana and North Dakota jurisdictions that have lower initial tax rates for an established period of time or until an established threshold of production is exceeded, after which the tax rates are increased to the standard tax rate.

General and Administrative Expense

General and administrative expense was $9.5 million for the third quarter of 2012 compared to $4.1 million for the third quarter of 2011. General and administrative expense for the third quarter of 2012 includes a severance charge in connection with the separation of our former president comprised of $4.3 million of non-cash share based compensation and other expenses estimated at $0.6 million. The third quarter of 2012 increase of $5.4 million when compared to third quarter of 2011 was primarily due to the $4.9 million in severance expense. Excluding the $4.9 million in severance expenses, the increase in general and administrative expenses was due to higher salary and benefit costs ($1.1 million), partially offset by lower legal and other professional services ($0.5 million) and lower travel expenses ($0.1 million). As a result of our growth, we increased staffing in the legal, finance and land departments.

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Depletion, Depreciation and Amortization

Depletion, depreciation and amortization ("DD&A") was $28.1 million in the third quarter of 2012 compared to $10.8 million in the third quarter of 2011. Depletion expense, the largest component of DD&A, was $26.93 per Boe in the third quarter of 2012 compared to $20.34 per Boe in the third quarter of 2011. The aggregate increase in depletion expense for third quarter of 2012 compared to the third quarter of 2011 was driven by a 96% increase in production. Additionally, depletion rates rose in third quarter of 2012 due to an increase in our future development and operating cost estimates to reflect the changes in well completion methodologies (e.g. more stimulation costs per well due to longer lateral extensions). Depletion rates in new plays tend to be higher in the beginning as increased initial outlays are amortized over proved reserves based on early stages of evaluations. As these plays mature, new technologies, well completion methodologies and additional historical operating information impact the reserve evaluations. Depreciation, amortization and accretion was $129,000 in third quarter of 2012 compared to $83,000 in the third quarter of 2011. The following table summarizes DD&A expense per Boe for the third quarters of 2012 and 2011:

	Three Months Ended September 30,			
	2012	2011	$ Change	% Change
Depletion per BOE	$26.93	$20.34	6.59	32
Depreciation, amortization, and accretion per BOE	0.12	0.16	(0.04)	(25)
Total DD&A expense per BOE	$27.05	$20.50	6.55	32

Interest Expense

Interest expense, net of capitalized interest, was $5.2 million for the third quarter of 2012 compared to $0.2 million in the third quarter of 2011. Capitalized interest was $1.8 million and $0 for the three month periods ended September 30, 2012 and 2011, respectively. The increase in interest expense between periods was primarily due to higher borrowing levels in 2012.

Income Tax Provision

The provision for income taxes was $0.2 million in the third quarter of 2012 compared to $17.2 million in the third quarter of 2011. The effective tax rate in the third quarter of 2012 was 41.6% compared to an effective tax rate of 37.5% in the third quarter of 2011. The effective tax rate was different than the statutory rate of 35% primarily due to state taxes and permanent differences.

Results of Operations for the nine month periods ended September 30, 2012 and September 30, 2011

The following table sets forth selected operating data for the periods indicated.

	Nine Months Ended September 30, 2012	2011	% Change
Net Production:			
Oil (Bbl)	2,555,994	1,203,057	112 %
Natural Gas (Mcf)	1,227,213	497,131	147
Total (Boe)	2,760,530	1,285,912	115
Net Sales:			
Oil Sales	$210,306,283	$102,932,359	104
Natural Gas Sales	5,962,429	3,271,545	82
Loss on Settled Derivatives	(4,729,186)	(10,695,006)	(56)
Unrealized Gain on Derivative Instruments	18,125,928	26,675,003	(32)
Other Revenue	160,752	218,984	(27)
Total Revenues	229,826,206	122,402,885	88
Average Sales Prices:			
Oil (per Bbl)	$82.28	$85.56	(4)
Effect of Loss on Settled Derivatives on Average Price (per Bbl)	(1.85)	(8.89)	79
Oil Net of Settled Derivatives (per Bbl)	80.43	76.67	5
Natural Gas and other liquids (per Mcf)	4.86	6.58	(26)
Realized price on a Boe basis including all realized derivative settlements	76.63	74.27	3
Operating Expenses:			
Production Expenses	$22,540,237	$8,542,761	164
Production Taxes	20,829,732	10,188,308	104
General and Administrative Expense (Including Share Based Compensation)	18,568,696	10,113,995	84
General and Administrative Expense (Non-Cash Share Based Compensation)	11,295,666	5,552,245	103
Depletion of Oil and Gas Properties	71,781,894	25,962,463	176
Costs and Expenses (per Boe):			
Production Expenses	$8.17	$6.64	23
Production Taxes	7.55	7.92	(5)
General and Administrative Expense (Including Share Based Compensation)	6.73	7.87	(14)
General and Administrative Expense (Non-Cash Share Based Compensation)	4.09	4.32	(5)
Depletion of Oil and Gas Properties	26.00	20.19	29
Net Producing Wells at Period End	98.5	43.6	126

Oil and Natural Gas Sales

During the first nine months of 2012, oil, natural gas and NGL sales, including the effect of settled derivatives, increased 121% as compared to the first nine months of 2011, driven primarily by a 115% increase in production and partially aided by a 3% increase in realized prices taking into account the effect of settled derivatives. Partially offsetting the higher average realized price in the first nine months of 2012 as compared to the same period in 2011 was a higher oil price differential. The oil price differential during the first nine months of 2012 was $12.50 per barrel, as compared to $6.93 per barrel in the first nine months of 2011.

As discussed above, our production continues to grow through drilling success as we place new wells into production and through additions from acquisitions, partially offset by the natural decline of our oil and natural gas sales from existing wells. During the first nine months of 2012, our average daily production volumes increased 114% as compared to the first nine months of 2011. The production increased primarily due to the addition of more net productive wells in 2012 as compared to 2011.

Derivative Instruments

In the first nine months of 2012, we incurred a loss on settled derivatives of $4.7 million, compared to $10.7 million loss for the first nine months of 2011. Our average realized price (including all derivative settlements) received during the first nine months of 2012 was $76.63 per Boe compared to $74.27 per Boe in the first nine months of 2011 due to higher average NYMEX prices in 2012. Our average realized price (including all derivative settlements) calculation includes all cash settlements for derivatives.

We had unrealized gains on derivative instruments of $18.1 million in the first nine months of 2012 compared to a $26.7 million gain in the first nine months of 2011. At September 30, 2012, all of our derivative contracts were recorded at their fair value, which was a net asset of $6.3 million, an increase of $18.2 million from the $11.9 million net liability recorded as of December 31, 2011

Production Expenses

Production expenses were $22.5 million in the first nine months of 2012 compared to $8.5 million in the first nine months of 2011. We experience increases in operating expenses as we add new wells and maintain production from existing properties. On a per unit basis, production expenses increased from $6.64 per Boe in the first nine months of 2011 to $8.17 in the first nine months of 2012. On an absolute dollar basis, our production expenses in the first nine months of 2012 were 164% higher when compared to the same period in 2011 due to a 115% increase in production levels, as well as, higher water hauling and disposal costs and higher workover expenses. These increases were due to an increased number of producing wells, increased water production and increased costs associated with salt water trucking and disposal during 2012 as compared to 2011.

Production Taxes

We pay production taxes based on realized crude oil and natural gas sales. These costs were $20.8 million in the first nine months of 2012 compared to $10.2 million in the first nine months of 2011. As a percent of oil and gas sales, our production taxes were 9.6% and 9.6% in the first nine months of 2012 and 2011, respectively.

General and Administrative Expense

General and administrative expense was $18.6 million for the first nine months of 2012 compared to $10.1 million for the first nine months of 2011. General and administrative expense for the first nine months of 2012 include a severance charge in connection with the separation of our former president comprised of $4.3 million of non-cash, share based compensation and other expenses estimated at $0.6 million. The first nine months of 2012 increase of $8.5 million when compared to first nine months of 2011 was primarily due to the $4.9 million in severance expense. Excluding the $4.9 million in severance expenses, the increase in general and administrative expenses was due to higher salary and benefit costs ($3.5 million) and higher travel expense ($0.1 million). As a result of our growth, we increased staffing in the legal, finance and land departments.

Depletion, Depreciation and Amortization

Depletion, depreciation and amortization (“DD&A”) was $72.1 million in the first nine months of 2012 compared to $26.2 million in the first nine months of 2011. Depletion expense, the largest component of DD&A, was $26.00 per Boe in the first nine months of 2012 compared to $20.19 per Boe in the first nine months of 2011. The aggregate increase in depletion expense for first nine months of 2012 compared to the first nine months of 2011 was driven by a 115% increase in production. Additionally, depletion rates rose in first nine months of 2012 due to an increase in our future development and operating cost estimates to reflect the changes in well completion methodologies (e.g. more stimulation costs per well due to longer lateral extensions). Depletion rates in new plays tend to be higher in the beginning as increased initial outlays are amortized over proved reserves based on early stages of evaluations. As these plays mature, new technologies, well completion methodologies and additional historical operating information impact the reserve evaluations. Depreciation, amortization and accretion was $0.4 million in the first nine months of 2012 compared to $0.2 million in the first nine months of 2011. The following table summarizes DD&A expense per Boe for the first nine months of 2012 and 2011:

	Nine Months Ended September 30,			
	2012	2011	$ Change	% Change
Depletion per BOE	$26.00	$20.19	5.81	29
Depreciation, amortization, and accretion per BOE	0.13	0.18	(0.05)	(28)
Total DD&A expense per BOE	$26.13	$20.37	5.76	28

Interest Expense

Interest expense, net of capitalized interest, was $8.1 million for the first nine months of 2012 compared to $0.4 million in the first nine months of 2011. The increase in interest expense between periods was primarily due to higher borrowing levels in 2012

Interest Income

During the first nine months of 2012 we had $1,206 of interest income as compared to $0.6 million in the first nine months of 2011. Interest income for the first nine months of 2012 decreased as compared to the first nine months of 2011 because of lower levels of cash and short term investments. The higher amount of cash and short term investments in 2011 resulted from the sale of common stock in November 2010.

Income Tax Provision

The provision for income taxes was $34.9 million in the first nine months of 2012 compared to a provision of $25.7 million in the first nine months of 2011. The effective tax rate in the first nine months of 2012 was 39.8% compared to an effective tax rate of 38.0% in the first nine months of 2011. The higher pre-tax income levels caused us to increase our federal statutory rate from 34% to 35% in 2012. The effective tax rate was different than the statutory rate of 35% primarily due to state tax rates and permanent differences.

Non-GAAP Financial Measures

We define Adjusted Net Income as net income excluding (i) unrealized gain (loss) on derivative instruments, net of tax and (ii) severance expenses in connection with the departure of our former president, net of tax. Our Adjusted Net Income for the three months ended September 30, 2012, was $16.7 million (representing approximately $0.27 per diluted share), as compared to $11.9 million (representing approximately $0.19 per diluted share) for the three months ended September 30, 2011. Our Adjusted Net Income for the nine months ended September 30, 2012, was $44.8 million (representing approximately $0.71 per diluted share), as compared to $25.5 million (representing approximately $0.41 per diluted share) for the nine months ended September 30, 2011. These increases in Adjusted Net Income are primarily due to our continued addition of crude oil and natural gas production from new wells and higher realized commodity prices in 2012 compared to 2011.

We define Adjusted EBITDA as net income before (i) interest expense, (ii) income taxes, (iii) depreciation, depletion, amortization, and accretion, (iv) unrealized gain (loss) on derivative instruments and (v) non-cash share based compensation expense. Adjusted EBITDA for the three months ended September 30, 2012 was $63.1 million, compared to Adjusted EBITDA of $31.9 million for the three months ended September 30, 2011. Adjusted EBITDA for the nine months ended September 30, 2012 was $161.1 million, compared to Adjusted EBITDA of $73.2 million for the nine months ended September 30, 2011. These increases in Adjusted EBITDA are primarily due to our continued addition of crude oil and natural gas production from new wells and higher realized commodity prices in 2012 compared to 2011.

We believe the use of these non-GAAP financial measures provides useful information to investors to gain an overall understanding of our current financial performance. Specifically, we believe the non-GAAP financial measures included herein provide useful information to both management and investors by excluding certain expenses and unrealized commodity gains and losses that our management believes are not indicative of our core operating results. In addition, these non-GAAP financial measures are used by management for budgeting and forecasting as well as subsequently measuring our performance, and we believe that we are providing investors with financial measures that most closely align to our internal measurement processes. We consider these non-GAAP measures to be useful in evaluating our core operating results as they more closely reflect our essential revenue generating activities and direct operating expenses (resulting in cash expenditures) needed to perform these revenue generating activities. Our management also believes, based on feedback provided by the investment community, that the non-GAAP financial measures are necessary to allow the investment community to construct its valuation models to better compare our results with our competitors and market sector.

These measures should be considered in addition to results prepared in accordance with GAAP. In addition, these non-GAAP financial measures are not based on any comprehensive set of accounting rules or principles. We believe that non-GAAP financial measures have limitations in that they do not reflect all of the amounts associated with our results of operations as determined in accordance with GAAP and that these measures should only be used to evaluate our results of operations in conjunction with the corresponding GAAP financial measures.

Adjusted Net income and Adjusted EBITDA are non-GAAP measures. A reconciliation of these measures to GAAP is included below:

NORTHERN OIL AND GAS, INC.
Reconciliation of GAAP Net Income to Adjusted Net Income
(UNAUDITED)

	Three Months Ended		Nine Months Ended	
	September 30, 2012	September 30, 2011	September 30, 2012	September 30, 2011
Net Income	$300,161	$28,617,222	$52,732,468	$41,992,280
Add:				
Unrealized Loss (Gain) on Derivative Instruments, Net of Tax (a)	13,429,470	(16,766,400)	(10,911,928)	(16,504,003)
Severance Expense, Net of Tax (b)	2,954,631	-	2,954,631	-
Adjusted Net Income	$16,684,262	$11,850,822	$44,775,171	$25,488,277
Weighted Average Shares Outstanding – Basic	62,589,256	61,919,641	62,410,110	61,708,537
Weighted Average Shares Outstanding – Diluted	62,882,673	62,265,502	62,753,241	62,114,115
Net Income Per Common Share – Basic	$-	$0.46	$0.84	$0.68
Add:				
Change due to Unrealized Loss (Gain) on Derivative Instruments, Net of Tax	0.22	(0.27)	(0.17)	(0.27)
Change due to Severance Expense, Net of Tax	0.05	-	0.05	-
Adjusted Net Income Per Common Share – Basic	$0.27	$0.19	$0.72	$0.41
Net Income Per Common Share – Diluted	$-	$0.46	$0.84	$0.68
Add:				
Change due to Unrealized Loss (Gain) on Derivative Instruments, Net of Tax	0.22	(0.27)	(0.17)	(0.27)
Change due to Severance Expense, Net of Tax	0.05	-	0.04	-
Adjusted Net Income Per Common Share – Diluted	$0.27	$0.19	$0.71	$0.41

(a) Adjusted to reflect related tax benefit (expense) of $8,879,000 and ($10,339,000) for the three months ended September 30, 2012 and 2011, respectively, and ($7,214,000) and ($10,171,000) for the nine months ended September 30, 2012 and 2011, respectively.

(b) Reflects severance expense recognized in connection with the departure of the Company's president and co-founder, Ryan Gilbertson. Adjusted to reflect related tax benefit expense of $1,954,000 for the three and nine months ended September 30, 2012, respectively.

Northern Oil and Gas, Inc.
Reconciliation of Adjusted EBITDA
(UNAUDITED)

	Three Months Ended		Nine Months Ended	
	September 30, 2012	September 30, 2011	September 30, 2012	September 30, 2011
Net Income	$300,161	$28,617,222	$52,732,468	$41,992,280
Add Back:				
Interest Expense	5,205,822	182,499	8,130,225	425,687
Income Tax Provision	213,422	17,173,000	34,878,772	25,725,300
Depreciation, Depletion, Amortization, and Accretion	28,081,124	10,832,762	72,147,282	26,196,973
Non – Cash Share Based Compensation	6,998,765	2,188,900	11,295,664	5,552,245
Unrealized Loss (Gain) on Derivative Instruments	22,308,470	(27,105,400)	(18,125,928)	(26,675,003)
Adjusted EBITDA	$63,107,764	$31,888,983	$161,058,483	$73,217,482

Liquidity and Capital Resources

Overview

Historically, our main sources of liquidity and capital resources have been internally generated cash flow from operations, credit facility borrowings and issuances of equity. We generally maintain low cash and cash equivalent balances because we use cash from operations to fund our development activities or reduce our bank debt. We continue to take steps to ensure adequate capital resources and liquidity to fund our capital expenditure program. In February 2012, we amended and restated the credit agreement governing our revolving credit facility (the "Revolving Credit Facility") to increase the maximum facility size to $750 million, subject to a borrowing base that is currently $350 million. In May 2012, we issued $300 million aggregate principal amount of 8.000% senior unsecured notes (the "Notes") due June 1, 2020. The issuance of these Notes resulted in net proceeds to us of approximately $291.2 million, which are in use to fund our exploration, development and acquisition program and for general corporate purposes (including repayment of borrowings that were outstanding under the Revolving Credit Facility at the time the Notes were issued).

At September 30, 2012, our debt to total book capitalization ratio was 39%, we had $68.0 million in borrowings under our Revolving Credit Facility, $300.0 million aggregate principal amount of Notes outstanding, $565.4 million of stockholders' equity, and $8.2 million of cash on hand. At December 31, 2011, we had $69.9 million of debt outstanding, $496.6 million of stockholders' equity, and $6.3 million of cash on hand.

Cash Flow

Cash flows from operations are primarily affected by production volumes and commodity prices, net of the effects of settlements of our derivatives. Our cash flows from operations also are impacted by changes in working capital. We generally maintain low cash and cash equivalent balances because we use cash from operations to fund our development activities or reduce our bank debt. Short-term liquidity needs are satisfied by borrowings under our Revolving Credit Facility. We generally use derivatives to economically hedge a significant, but varying portion of our anticipated future production for the next 12 to 36 months. Any payments due to counterparties under our derivative contracts are funded by proceeds received from the sale of our production. Production receipts, however, lag payments to the counterparties. Any interim cash needs are funded by cash from operations or borrowings under our Revolving Credit Facility.

Our cash flows for the nine month periods ended September 30, 2012 and 2011 are presented below:

	Nine Months Ended September 30,	
	2012	2011
	(unaudited)	
Net cash provided by operating activities	$136,696,932	$49,385,866
Net cash used for investing activities	(419,872,414)	(209,481,773)
Net cash provided by financing activities	285,130,461	16,250,853
Net change in cash	$1,954,979	$(143,845,054)

Cash flows provided by operating activities

Net cash provided by operating activities for the nine months ended September 30, 2012 was $136.7 million compared to $49.4 million during the nine months ended September 30, 2011. This increase was due to higher production from development activity, which was partially offset by higher operating costs. Net cash provided by operating activities is also affected by working capital changes or the timing of cash receipts and disbursements. Changes in working capital in the nine months ended September 30, 2012 was an increase of $17.2 million compared to an increase of $23.5 million in the same period of the prior year.

Cash flows used in investing activities

We had cash flows used in investing activities of $419.9 million and $209.5 million during the nine month periods ended September 30, 2012 and 2011, respectively, primarily as a result of our capital expenditures for drilling, development and acquisition costs. The increase in cash used in investing activities for the first nine months of 2012 as compared to same period of the prior year was attributable to our acquisitions of properties in the Williston Basin, as well as increased levels of development of our properties. During the first nine months of 2012, we added 40.6 net producing wells compared to approximately 17.4 net producing wells during the first nine months of 2011. At September 30, 2012 we were drilling or awaiting completion on 10.1 net wells.

Cash flows provided by financing activities

Net cash provided by financing activities was $285.1 million and $16.3 million during the nine months ended September 30, 2012 and 2011, respectively. For the nine months ended September 30, 2012, we issued $300 million in senior notes, incurred $11.9 million of debt issuance costs in connection with the senior notes offering and had net repayments on our Revolving Credit Facility of $1.9 million. The proceeds from these borrowings are in use to fund our exploration, development and acquisition program and for general corporate purposes.

Revolving Credit Facility

As of December 31, 2011, we maintained a $500 million revolving credit facility that was secured by substantially all of our assets with a maturity of May 26, 2014. We had $69.9 million of borrowings under that revolving credit facility at December 31, 2011. At December 31, 2011, we had a borrowing base of $150 million, subject to a $120 million aggregate maximum credit amount that provided $50.1 million of additional borrowing capacity under that facility.

In February 2012, we entered into an amended and restated credit agreement governing our Revolving Credit Facility, which replaced our previous revolving credit facility. The new facility, secured by substantially all of our assets, provides for an initial commitment equal to the lesser of the facility amount or the borrowing base. At September 30, 2012, the maximum facility amount was $750 million and the borrowing base was $350 million. Our bank group is comprised of a group of commercial banks, with no single bank holding more than 12% of the total facility. Under the terms of the Revolving Credit Facility, we are limited to $500 million of permitted additional indebtedness, as defined in the credit agreement. The borrowing base is reduced by 25% of the stated amount of the permitted additional indebtedness. The Revolving Credit Facility provides for a borrowing base subject to redetermination semi-annually each April and October and for event-driven unscheduled redeterminations. As of September 30, 2012, there were $68.0 million in borrowings under our Revolving Credit Facility, leaving $282 million of borrowing capacity available to us. The Revolving Credit Facility will expire and all outstanding borrowings under it will mature on January 1, 2017. Borrowings under the Revolving Credit Facility can either be at the Alternate Base Rate (as defined) plus a spread ranging from 0.75% to 1.75% or LIBOR borrowings at the Adjusted LIBOR Rate (as defined) plus a spread ranging from 1.75% to 2.75%. The applicable spread is dependent upon borrowings relative to the borrowing base. We may elect, from time to time, to convert all or any part of our LIBOR loans to base rate loans or to convert all or any of the base rate loans to LIBOR loans. A commitment fee is paid on the undrawn balance based on an annual rate of either 0.375% or 0.50%, depending on outstanding borrowings relative to the borrowing base. The Revolving Credit Facility is subject to negative covenants that limit our ability, among other things, to pay cash dividends, incur additional indebtedness, sell assets, enter into certain hedging contracts, change the nature of our business or operations, merge, consolidate, or make certain types of investments. In addition, we are required to maintain a ratio of debt to EBITDAX (as defined in the credit agreement) of no greater than 4.0 to 1.0, a current ratio (as defined in the credit agreement) of no less than 1.0 to 1.0 and a ratio of EBITDAX to interest expense of no less than 3.0 to 1.0. We were in compliance with our covenants under the Revolving Credit Facility at September 30, 2012.

8.000% Senior Notes due 2020

On May 18, 2012, we issued $300 million aggregate principal amount of 8.000% senior unsecured notes due June 1, 2020 (the “Notes”). Interest is payable on the Notes semi-annually in arrears on each June 1 and December 1, commencing December 1, 2012. The issuance of these Notes resulted in net proceeds to us of approximately $291.2 million, which are in use to fund our exploration, development and acquisition program and for general corporate purposes (including repayment of borrowings that were outstanding under our Revolving Credit Facility at the time the Notes were issued).

At any time prior to June 1, 2015, we may redeem up to 35% of the Notes at a redemption price of 108% of the principal amount, plus accrued and unpaid interest to the redemption date, with the proceeds of certain equity offerings so long as the redemption occurs within 180 days of completing such equity offering and at least 65% of the aggregate principal amount of the Notes remains outstanding after such redemption. Prior to June 1, 2016, we may redeem some or all of the Notes for cash at a redemption price equal to 100% of their principal amount plus an applicable make-whole premium and accrued and unpaid interest to the redemption date. On and after June 1, 2016, we may redeem some or all of the Notes at redemption prices (expressed as percentages of principal amount) equal to 104% for the twelve-month period beginning on June 1, 2016, 102% for the twelve-month period beginning June 1, 2017 and 100% beginning on June1, 2018, plus accrued and unpaid interest to the redemption date.

On May 18, 2012, in connection with the issuance of the Notes, we entered into an Indenture (the "Base Indenture"), with Wilmington Trust, National Association, as trustee (the "Trustee").

The Indenture restricts our ability to: (i) incur additional debt or enter into sale and leaseback transactions; (ii) pay distributions on, redeem or repurchase, equity interests; (iii) make certain investments; (iv) incur liens; (v) enter into transactions with affiliates; (vi) merge or consolidate with another company; and (vii) transfer and sell assets. These covenants are subject to a number of important exceptions and qualifications. If at any time when the Notes are rated investment grade by both Moody's Investors Service, Inc. and Standard & Poor's Ratings Services and no Default (as defined in the Indenture) has occurred and is continuing, many of such covenants will terminate and we and any of our subsidiaries will cease to be subject to such covenants.

The Indenture contains customary events of default, including:

- default in any payment of interest on any Note when due, continued for 30 days;
- default in the payment of principal of or premium, if any, on any Note when due;
- failure by us to comply with our other obligations under the Indenture, in certain cases subject to notice and grace periods;
- payment defaults and accelerations with respect to other indebtedness of Northern and our Restricted Subsidiaries (as defined in the Indenture) in the aggregate principal amount of $25 million or more;
- certain events of bankruptcy, insolvency or reorganization of Northern or a Significant Subsidiary (as defined in the Indenture) or group of Restricted Subsidiaries that, taken together, would constitute a Significant Subsidiary;
- failure by us or any Significant Subsidiary or group of Restricted Subsidiaries that, taken together, would constitute a Significant Subsidiary to pay certain final judgments aggregating in excess of $25 million within 60 days; and
- any guarantee of the Notes by a Guarantor ceases to be in full force and effect, is declared null and void in a judicial proceeding or is denied or disaffirmed by its maker.

Capital Expenditures

Our primary needs for cash are for exploration, development and acquisition of oil and natural gas properties and payment of interest on outstanding indebtedness. Development and acquisition activities are highly discretionary and we monitor our capital expenditures on a regular basis, adjusting the amount up or down depending on projected commodity prices, cash flows and returns. Total drilling and completion cost in the Williston Basin generally ranges from approximately $7 to $10 million per well, and can vary based on vertical depth of the well, lateral length and completion techniques.

2012 Drilling and Acreage Plan

In the first nine months of 2012, we participated in the spudding of 32.7 net wells and we reaffirm our expectation to participate in the spudding of approximately 44 net wells for the year. Based on current drilling and completion costs reflected on authority for expenditures (AFE's) received from operating partners, we estimate the average completed well cost will be $8.7 million for the remainder of 2012. In the first nine months of 2012 we spent approximately $225 million on drilling expenditures and $33.8 on acreage expenditures in connection with our 2012 capital budget. The 2012 budget does not include approximately $181.1 million of capital that was related to wells spud prior to 2012 that was included in the first nine months of 2012 capital expenditures. The majority of these expenditures for wells spud prior to 2012 relate to wells that were drilling or awaiting completion at December 31, 2011 that were subsequently completed in 2012 as a result of a greater availability of completion (frac) crews. Total capital expenditure for the first nine months of 2012 include $406.3 in drilling expenditures, $33.8 in acreage expenditures, $7.4 million in internal capitalized costs, $4.4 million in capitalized interest, as well as $0.4 million in costs related to asset retirement obligations.

The forward-looking statements about our capital budget are based on current expectations, estimates and projections and are not guarantees of future performance. Actual results may differ materially from these expectations, estimates and projections and are subject to certain risks, uncertainties and other factors, some of which are beyond our control and are difficult to predict. Some factors that could cause actual results to differ materially include prices of and demand for crude oil and natural gas, actions of operating partners and competitors, changes in methods and costs for drilling and completion of wells, disruptions or interruptions of our production and unforeseen hazards such as weather conditions, acts of war or terrorists acts and the government or military response, and other operating and economic considerations.

Significant Accounting Policies

Our critical accounting policies involving significant estimates include impairment testing of natural gas and crude oil production properties, asset retirement obligations, revenue recognition, derivative instruments and hedging activity, and income taxes. There were no material changes in our critical accounting policies involving significant estimates from those reported in our 2011 Annual Report on Form 10-K.

A description of our critical accounting policies was provided in Note 2 to the Financial Statements provided in Part II, Item 8 of our Annual Report on Form 10-K for the fiscal year ended December 31, 2011.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

Our quantitative and qualitative disclosures about market risk for changes in commodity prices and interest rates are included in Item 7A of our Annual Report on Form 10-K for the fiscal year ended December 31, 2011 and, except as set forth below, have not materially changed since that report was filed.

Commodity Price Risk

The price we receive for our oil and natural gas production heavily influences our revenue, profitability, access to capital and future rate of growth. Oil and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil and natural gas have been volatile, and our management believes these markets will likely continue to be volatile in the future. The prices we receive for our production depend on numerous factors beyond our control. Our revenue during 2011 generally would have increased or decreased along with any increases or decreases in oil or natural gas prices, but the exact impact on our income is indeterminable given the variety of expenses associated with producing and selling oil that also increase and decrease along with oil prices.

We enter into derivative contracts to achieve a more predictable cash flow by reducing our exposure to oil price volatility. On November 1, 2009, due to the volatility of price differentials in the Williston Basin, we de-designated all derivatives that were previously classified as cash flow hedges and we have elected not to designate any subsequent derivative contracts as accounting hedges. As such, all derivative positions are carried at their fair value on the balance sheet and are marked-to-market at the end of each period. Any realized gains and losses are recorded to gain (loss) on settled derivatives and unrealized mark–to-market gains or losses are recorded to unrealized gain (loss) on derivative instruments on the statement of income rather than as a component of other comprehensive income (loss) or other income (expense).

We generally use derivatives to economically hedge a significant, but varying portion of our anticipated future production over a rolling 36 month horizon. Any payments due to counterparties under our derivative contracts are funded by proceeds received from the sale of our production. Production receipts, however, lag payments to the counterparties. Any interim cash needs are funded by cash from operations or borrowings under our Revolving Credit Facility. As of September 30, 2012, we had entered into derivative agreements covering 0.9 million barrels for the remainder of 2012, 2.9 million barrels for 2013 and 2.0 million barrels for 2014.

The following table summarizes the oil derivative contracts that we have entered into for each year as of September 30, 2012:

Settlement Period	Oil (Barrels)	Fixed Price	Weighted Avg NYMEX Reference Price
Oil Swaps			
10/01/12 – 12/31/12	60,000	$90.40	$92.73
10/01/12 – 12/31/14	540,000	91.65	92.61
10/01/12 – 12/31/12	60,000	97.80	92.21
10/01/12 – 12/31/12	30,000	104.50	92.75
10/01/12 – 12/31/12	150,000	88.00	92.73
10/01/12 – 12/31/12	142,500	95.15	92.72
10/01/12 – 12/31/12	60,000	100.00	92.74
01/01/13 – 12/31/13	300,000	89.50	93.61
01/01/13 – 12/31/13	240,000	91.10	93.70
07/01/13 – 12/31/13	60,000	102.30	93.51
01/01/14 – 06/30/14	300,000	89.50	92.03
01/01/14 – 06/30/14	240,000	90.00	92.44
01/01/14 – 12/31/14	240,000	90.15	91.49
01/01/14 – 12/31/14	240,000	91.00	91.49
01/01/14 – 06/30/14	240,000	100.00	92.46
07/01/14 – 12/31/14	120,000	90.00	90.87
07/01/14 – 12/31/14	120,000	93.50	90.90

Term	Oil (Barrels)		Price	Basis
Costless Collars				
10/01/12 – 12/31/12	60,000	$	90.00/$98.50	NYMEX
10/01/12 – 12/31/12	33,308	$	85.00/$95.25	NYMEX
10/01/12 – 12/31/12	60,000	$	95.00/$115.10	NYMEX
10/01/12 – 12/31/13	199,026	$	90.00/$103.50	NYMEX
10/01/12 – 12/31/13	188,018	$	90.00/$106.50	NYMEX
10/01/12 – 12/31/13	292,580	$	90.00/$110.00	NYMEX
10/01/12 – 12/31/13	247,683	$	95.00/$107.00	NYMEX
01/01/13 – 12/31/13	480,000	$	95.00/$110.70	NYMEX
01/01/13 – 12/31/13	760,794	$	85.00/$98.00	NYMEX
07/01/13 – 12/31/13	96,000	$	95.00/$106.90	NYMEX

01/01/14 – 12/31/14	240,000	$	90.00/$99.05	NYMEX

Interest Rate Risk

Our long-term debt is comprised of borrowings that contain fixed and floating interest rates. The Notes bear interest at an annual fixed rate of 8% and our Revolving Credit Facility interest rate is a floating rate option that is designated by us. During the first nine months of 2012, we had $102.0 million in average outstanding borrowings under our credit facility at a weighted average rate of 1.65%. We have the option to designate the reference rate of interest for each specific borrowing under the credit facility as amounts are advanced. Borrowings based upon the London Interbank Offered Rate ("LIBOR") will bear interest at a rate equal to LIBOR plus a spread ranging from 1.75% to 2.75% depending on the percentage of borrowing base that is currently advanced. Any borrowings not designated as being based upon LIBOR will bear interest at a rate equal to the current prime rate published by the Wall Street Journal, plus a spread ranging from 0.75% to 1.75%, depending on the percentage of borrowing base that is currently advanced. We have the option to designate either pricing mechanism. Interest payments are due under the credit facility in arrears, in the case of a loan based on LIBOR on the last day of the specified interest period and in the case of all other loans on the last day of each March, June, September and December. All outstanding principal is due and payable upon termination of the credit facility.

Our credit facility allows us to fix the interest rate of borrowings under it for all or a portion of the principal balance for a period up to three months; however our borrowings are generally withdrawn with interest rates fixed for one month. Thereafter, to the extent we do not repay the principle, our borrowings are rolled over and the interest rate is reset based on the current LIBOR or prime rate as applicable. As a result, changes in interest rates can impact results of operations and cash flows. A 1% increase in short-term interest rates on the floating-rate debt during the first nine months of 2012 would cost us approximately $1.0 million in additional annual interest expense.

Item 4. Controls and Procedures.

Evaluation of Disclosure Controls and Procedures

We maintain a system of disclosure controls and procedures that is designed to ensure that information required to be disclosed in our Exchange Act reports is recorded, processed, summarized and reported within the time periods specified in rules and forms of the SEC, and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosures.

As of September 30, 2012, our management, including our Chief Executive Officer and Chief Financial Officer, had evaluated the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) pursuant to Rule 13a-15(b) under the Exchange Act. Based upon and as of the date of the evaluation, our Chief Executive Officer and Chief Financial Officer concluded that information required to be disclosed is recorded, processed, summarized and reported within the specified periods and is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, to allow for timely decisions regarding required disclosure of material information required to be included in our periodic SEC reports. Based on the foregoing, our management determined that our disclosure controls and procedures were effective as of September 30, 2012.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting that occurred during the quarter ended September 30, 2012 that materially affected or are reasonably likely to materially affect our internal control over financial reporting.

PART II - OTHER INFORMATION

Item 1. Legal Proceedings.

Our company is subject from time to time to litigation claims and governmental and regulatory proceedings arising in the ordinary course of business.

Item 1A. Risk Factors.

There have been no material changes to the risk factors disclosed in the "Risk Factors" section of our Quarterly Report on Form 10-Q filed with the SEC for the period ended March 31, 2012.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds.

Recent Sales of Unregistered Securities

We did not issue any unregistered equity securities during the quarter ended September 30, 2012.

Issuer Purchases of Equity Securities

No purchases of our common stock were made by or on behalf of our Company, or any "affiliated purchaser" (as defined in Rule 10b-18(a)(3) under the Securities Exchange Act of 1934), during the quarter ended September 30, 2012.

In May 2011, our board of directors approved a stock repurchase program to acquire up to $150 million shares of our Company's outstanding common stock. The stock repurchase program will allow us to repurchase our shares from time to time in the open market, block transactions and in negotiated transactions. We have not made any repurchases under this program to date.

Item 6. Exhibits.

The exhibits listed in the accompanying exhibit index are filed as part of this Quarterly Report on Form 10-Q.

SIGNATURES

In accordance with the requirements of the Exchange Act, the Registrant has caused this Quarterly Report to be signed on its behalf by the undersigned, thereunto duly authorized.

NORTHERN OIL AND GAS, INC.

Date: November 8, 2012	By: /s/ Michael L. Reger Michael L. Reger, Chief Executive Officer and Director
Date: November 8, 2012	By: /s/ Thomas W. Stoelk Thomas W. Stoelk, Chief Financial Officer

EXHIBIT INDEX

Exhibit No.	Description	Reference
3.1	Articles of Incorporation of Northern Oil and Gas, Inc. dated June 28, 2010	Incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed with the SEC on July 2, 2010
3.2	By-Laws of Northern Oil and Gas, Inc.	Incorporated by reference to Exhibit 3.2 to the Registrant's Current Report on Form 8-K filed with the SEC on July 2, 2010
4.1	Specimen Stock Certificate of Northern Oil and Gas, Inc.	Incorporated by reference to Exhibit 4.1 to the Registrant's Annual Report on Form 10-K filed with the SEC on February 29, 2012
4.2	Indenture, dated May 18, 2012, between Northern Oil and Gas, Inc. and Wilmington Trust, National Association, as trustee (including Form of 8.000% Senior Note due 2020)	Incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed with the SEC on March 18, 2012
4.3	Registration Rights Agreement, dated May 18, 2012, by and between Northern Oil and Gas, Inc. and RBC Capital Markets, LLC as representative of the Initial Purchasers	Incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K filed with the SEC on March 18, 2012
10.1	Separation Agreement and Release, dated October 1, 2012, between Northern Oil and Gas, Inc. and Ryan R. Gilbertson	Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on October 1, 2012
10.2	Consulting Agreement, dated October 1, 2012, between Northern Oil and Gas, Inc. and Ryan R. Gilbertson	Incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed with the SEC on October 1, 2012
10.3	Second Amendment to Third Amended and Restated Credit Agreement, dated September 28, 2012, by and among Northern Oil and Gas, Inc., Royal Bank of Canada, and the Lenders Party thereto	Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on October 2, 2012
31.1	Certification of the Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14(a) under the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
31.2	Certification of the Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14(a) under the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
32.1	Certification of the Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	Filed herewith
101.INS	XBRL Instance Document(1)	Filed herewith
101.SCH	XBRL Taxonomy Extension Schema Document(1)	Filed herewith
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document(1)	Filed herewith
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document(1)	Filed herewith
101.LAB	XBRL Taxonomy Extension Label Linkbase Document(1)	Filed herewith
101.PRE		Filed herewith

	XBRL Taxonomy Extension Presentation Linkbase Document(1)

(1) The XBRL related information in Exhibit 101 to this Quarterly Report on Form 10-Q shall not be deemed “filed” for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to liability of that section and shall not be incorporated by reference into any filing or other document pursuant to the Securities Act of 1933, as amended, except as shall be expressly set forth by specific reference in such filing or document.