NORTHERN OIL & GAS, INC.
Form 10-Q
August 09, 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 June 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 £ (Do not check if a smaller reporting company)	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 August 7, 2012, there were 63,618,352 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 acreage. 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 acres under the bit" or "net acreage under the bit." The net leased acres on which wells are spud, drilling, drilled, awaiting completion or completing in the spacing unit only, and not yet classified as developed acreage, regardless of whether or not such acreage contains proved reserves. Acreage included in spacing units of infill wells is not considered under the bit because such acreage was already previously classified as developed acreage when the initial well was completed in the subject spacing unit.

"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 under the bit and 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

June 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
JUNE 30, 2012 AND DECEMBER 31, 2011

	June 30, 2012 (UNAUDITED)	December 31, 2011
CURRENT ASSETS		
Cash and Cash Equivalents	$ 25,171,675	$ 6,279,587
Trade Receivables	66,063,522	51,418,830
Advances to Operators	7,023,970	17,530,474
Prepaid Expenses	875,212	486,421
Other Current Assets	240,551	317,460
Derivative Instruments	17,732,562	-
Deferred Tax Asset	-	4,472,000
Total Current Assets	117,107,492	80,504,772
PROPERTY AND EQUIPMENT		
Oil and Natural Gas Properties, Full Cost Method of Accounting		
Proved	939,211,344	566,195,321
Unproved	98,102,110	137,784,903
Other Property and Equipment	3,161,246	2,988,641
Total Property and Equipment	1,040,474,700	706,968,865
Less - Accumulated Depreciation and Depletion	107,294,624	63,265,919
Total Property and Equipment, Net	933,180,076	643,702,946
DERIVATIVE INSTRUMENTS	10,865,174	-
DEBT ISSUANCE COSTS	12,444,823	1,386,201
TOTAL ASSETS	$ 1,073,597,565	$ 725,593,919
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Accounts Payable	$ 143,061,879	$ 110,133,286
Accrued Expenses	4,848,262	164,241
Derivative Instruments	-	9,363,068
Deferred Tax Liability	6,029,000	-
Total Current Liabilities	153,939,141	119,660,595
LONG-TERM LIABILITIES		
Revolving Credit Facility	-	69,900,000
8% Senior Notes Due 2020	300,000,000	-
Derivative Instruments	-	2,574,903
Other Noncurrent Liabilities	1,291,844	959,366
Deferred Tax Liability	60,127,000	35,929,000
Total Long-Term Liabilities	361,418,844	109,363,269

TOTAL LIABILITIES	515,357,985	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, (6/30/2012 – 63,612,352 Shares Outstanding and 12/31/2011 – 63,330,421 Shares Outstanding)	63,612	63,330
Additional Paid-In Capital	457,372,977	448,198,350
Retained Earnings	100,802,991	48,370,684
Accumulated Other Comprehensive Loss	-	(62,309)
Total Stockholders' Equity	558,239,580	496,570,055
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$1,073,597,565	$725,593,919

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

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

	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
REVENUES				
Oil and Gas Sales	$70,439,015	$35,481,664	$135,578,411	$62,523,285
Loss on Settled Derivatives	(1,094,885)	(5,608,231)	(6,430,482)	(8,870,287)
Unrealized Gain (Loss) on Derivative Instruments	49,799,311	20,848,232	40,434,398	(430,397)
Other Revenue	64,160	104,433	148,266	130,246
Total Revenues	119,207,601	50,826,098	169,730,593	53,352,847
OPERATING EXPENSES				
Production Expenses	7,292,253	2,615,546	13,805,601	4,631,902
Production Taxes	6,658,004	3,311,037	12,736,889	5,926,901
General and Administrative Expense	4,419,607	2,749,418	9,100,985	6,040,007
Depletion of Oil and Gas Properties	25,519,809	8,349,600	43,829,309	15,213,079
Depreciation and Amortization	102,307	70,295	199,396	138,608
Accretion of Discount on Asset Retirement Obligations	21,821	7,794	37,453	12,524
Total Expenses	44,013,801	17,103,690	79,709,633	31,963,021
INCOME FROM OPERATIONS	75,193,800	33,722,408	90,020,960	21,389,826
OTHER INCOME (EXPENSE)				
Interest Expense	(2,728,104)	(122,546)	(2,924,403)	(243,188)
Interest Income	700	137,944	1,100	565,629
(Loss) Gain on Available for Sale Securities	-	(244,906)	-	215,091
Total Other Income (Expense)	(2,727,404)	(229,508)	(2,923,303)	537,532
INCOME BEFORE INCOME TAXES	72,466,396	33,492,900	87,097,657	21,927,358
INCOME TAX PROVISION	28,840,000	13,060,000	34,665,350	8,552,300
NET INCOME	$43,626,396	$20,432,900	$52,432,307	$13,375,058
OTHER COMPREHENSIVE INCOME NET OF TAX				
Unrealized Gains on Marketable Securities (Net of Tax of $404,000 and $109,000 for the three and six months ended June 30, 2011, respectively)	-	630,761	-	173,846
Reclassification of Derivative Instruments Included in Income (Net of Tax of $111,000 for the Three Months Ended June 30, 2011 and $39,000 and $212,000 for the Six Months June 30, 2012 and 2011, respectively)	-	172,800	62,309	341,950
Total Other Comprehensive Income	$-	$803,561	$62,309	$515,796

COMPREHENSIVE INCOME	43,626,396	$21,236,461	$52,494,616	$13,890,854
Net Income Per Common Share - Basic	$0.70	$0.33	$0.84	$0.22
Net Income Per Common Share - Diluted	$0.70	$0.33	$0.84	$0.22
Weighted Average Shares Outstanding - Basic	62,399,869	61,686,463	62,319,553	61,586,603
Weighted Average Shares Outstanding - Diluted	62,705,473	62,053,888	62,687,814	62,028,292

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

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

	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 52,432,307	$ 13,375,058
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities:		
Depletion of Oil and Gas Properties	43,829,309	15,213,079
Depreciation and Amortization	199,396	138,608
Amortization of Debt Issuance Costs	532,264	180,341
Accretion of Discount on Asset Retirement Obligations	37,453	12,524
Deferred Income Taxes	34,660,000	8,550,000
Net Gain on Sale of Available for Sale Securities	-	(215,092)
Unrealized (Gain) Loss on Derivative Instruments	(40,434,398)	430,397
Amortization of Deferred Rent	(16,615)	(9,287)
Share - Based Compensation Expense	4,296,899	3,363,345
Changes in Working Capital and Other Items:		
Increase in Trade Receivables	(14,644,692)	(13,552,651)
Increase in Prepaid Expenses	(388,791)	(173,146)
Decrease in Other Current Assets	76,909	264,952
Increase in Accounts Payable	288,100	7,916,402
Increase in Accrued Expenses	4,693,308	158
Net Cash Provided By Operating Activities	85,561,449	35,494,688
CASH FLOWS FROM INVESTING ACTIVITIES		
Purchases of Oil and Gas Properties and Development Capital Expenditures	(283,868,815)	(154,374,342)
Advances to Operators	-	(2,529,779)
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	(172,605)	(73,692)
Net Cash Used For Investing Activities	(284,041,420)	(111,726,013)
CASH FLOWS FROM FINANCING ACTIVITIES		
Advances on Revolving Credit Facility	322,600,000	-
Repayments on Revolving Credit Facility	(392,500,000)	-
Advances on Senior Unsecured Notes	300,000,000	-
Debt Issuance Costs Paid	(11,590,886)	-
Repurchase of Common Stock	(1,173,315)	-
Proceeds from Exercise of Stock Options	36,260	-
Proceeds from Exercise of Warrants	-	1,500,000
Net Cash Provided by Financing Activities	217,372,059	1,500,000
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	18,892,088	(74,731,325)

CASH AND CASH EQUIVALENTS – BEGINNING OF PERIOD	6,279,587	152,110,701
CASH AND CASH EQUIVALENTS – END OF PERIOD	$25,171,675	$77,379,376
Supplemental Disclosure of Cash Flow Information		
Cash Paid During the Period for Interest	$1,922,026	$-
Cash Paid During the Period for Income Taxes	$5,350	$-
Non-Cash Financing and Investing Activities:		
Payment of Compensation through Issuance of Common Stock	$10,311,964	$12,227,060
Capitalized Asset Retirement Obligations	$302,353	$199,996
Non-Cash Compensation Capitalized in Oil and Gas Properties	$6,015,065	$8,863,715
The accompanying notes are an integral part of these financial statements.		

NOTES TO UNAUDITED CONDENSED FINANCIAL STATEMENTS
JUNE 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 and development of crude oil and natural gas properties. The Company's common stock trades on the NYSE MKT market under the symbol "NOG".

The Company acquires interests in crude oil and natural gas acreage and drilling projects, primarily in North Dakota and Montana that target the Bakken and Three Forks formations. In addition to developing its acreage the Company acquires non-operated working interests in wells within its area of operations. As of June 30, 2012, approximately 43% of our 180,588 total net mineral 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 $102,307 and $70,295 for the three months ended June 30, 2012 and 2011, respectively. Depreciation expense was $199,396 and $138,608 for the six months ended June 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 six months ended June 30, 2012 and 2011, respectively.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Capitalized Certain Payroll and Other Internal Costs	$3,082,191	$3,664,106	$7,286,630	$9,604,131
Capitalized Interest Costs	1,604,367	-	2,615,341	-
Total	$4,686,558	$3,664,106	$9,901,971	$9,604,131

As of June 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. Additionally, the Company held leasehold acreage in Yates County, New York that targets Trenton/Black River, Marcellus and Queenstown-Medina 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 $5,027,162 of proceeds from property sales in the six months ended June 30, 2011, which was credited to the full cost pool. There were no proceeds from property sales in the six months ended June 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 June 30, 2012 and 2011, the Company transferred into the full cost pool costs related to expired leases of $0.7 million and $2.4 million, respectively. For the six months ended June 30, 2012 and 2011, the Company transferred into the full cost pool costs related to expired leases of $2.6 million and $5.6 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 June 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 $5.5 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 June 30, 2012 and 2011 was $383,577 and $90,949, respectively. The amortization of debt issuance costs for the six months ended June 30, 2012 and 2011 was $532,264 and $180,341, 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 June 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 June 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 six months ended June 30, 2012 and 2011 are as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Weighted average common shares outstanding – basic	62,399,869	61,686,463	62,319,553	61,586,603
Plus: Potentially dilutive common shares				
Stock options, warrants, and restricted stock	305,604	367,425	368,261	441,689
Weighted average common shares outstanding – diluted	62,705,473	62,053,888	62,687,814	62,028,292
Restricted stock excluded from EPS due to the anti-dilutive effect	24,835	-	17,234	-

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 June 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.

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 June 30, 2012, approximately $138.7 million of capital expenditures were in accounts payable.

Acquisitions

For the six months ended June 30, 2012, the Company acquired or earned through farm-in arrangements approximately 17,338 net mineral acres, for an average cost of approximately $1,881 per net acre, in its key prospect areas in the form of effective leases.

For the six months ended June 30, 2011, the Company acquired approximately 24,281 net mineral acres, for an average cost of $1,808 per net acre, in its key prospect areas in the form of effective leases.

Unproved Properties

Unproved properties not being amortized comprise approximately 74,000 net acres and 117,000 net acres of undeveloped leasehold interests at June 30, 2012 and December 31, 2011, 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 150 gross (10.8 net) wells drilling, awaiting completion or completing as of June 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. At June 30, 2012 and December 31, 2011, the amount of capitalized costs excluded from depletion was $98.1 million and $137.8 million, respectively.

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 on a heads up basis 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. described below.

As of June 30, 2012, the Company was participating in three defined drilling projects with Slawson covering an aggregate of approximately 18,540 net acres of leasehold interests held by the Company. The Windsor project area 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 includes approximately 4,525 net acres held by the Company in Richland County, Montana. The Lambert project includes approximately 11,293 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 comprised of eleven banks. 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. On June 29, 2012, the Company entered into an amendment to the credit agreement governing its Revolving Credit Facility to increase the borrowing base to $300 million. At June 30, 2012, the facility amount was $750 million, the borrowing base was $300 million and there was no outstanding balance, leaving $300 million of borrowing capacity available under the facility. Under the terms of the Revolving Credit Facility, the Company is limited to $300 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 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 June 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 June 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 six months ended June 30, 2012 and the year ended December 31, 2011:

	Six Months Ended	Year Ended

	June 30, 2012	December 31, 2011
Beginning balance	63,330,421	62,129,424
Stock options exercised	7,000	3,500
Restricted stock grants (Note 6)	501,188	947,891
Warrants exercised	-	300,000
Other Surrenders	(226,257)	(50,394)
Ending balance	63,612,352	63,330,421

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2012 Activity

In January 2012 and April 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 six month period ended June 30, 2012, the Company had accrued bonuses of approximately $1.7 million based on the year to date results of operations in comparison to year-end bonus performance goals. During the six and three months ended June 30, 2012, the Company expensed approximately $800,000 and $475,000, respectively, in compensation related to this bonus accrual and capitalized the remaining into the full cost pool. The Company had accrued bonuses of approximately $1.4 million for the six months ended June 30, 2011, approximately $423,000 were expensed in share-based compensation for the six months ended June 30, 2011 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 six months ended June 30, 2012, the Company issued 501,188 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 June 30, 2012, there was approximately $18.0 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 six months ended June 30, 2012:

	Six Months Ended June 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	501,188		