NORTHERN OIL & GAS, INC.
Form 10-Q
May 07, 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 March 31, 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 May 4, 2012, there were 63,509,352 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:

"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 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 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.

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

“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.

“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.

“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

March 31, 2012

C O N T E N T S

PART I - FINANCIAL INFORMATION

Item 1. Financial Statements.

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

	March 31, 2012 (unaudited)	December 31, 2011
CURRENT ASSETS		
Cash and Cash Equivalents	$3,834,888	$6,279,587
Trade Receivables	61,365,535	51,418,830
Advances to Operators	12,546,787	17,530,474
Prepaid Expenses	995,145	486,421
Other Current Assets	389,656	317,460
Deferred Tax Asset	6,625,000	4,472,000
Total Current Assets	85,757,011	80,504,772
PROPERTY AND EQUIPMENT		
Oil and Natural Gas Properties, Full Cost Method of Accounting		
Proved	717,342,914	566,195,321
Unproved	141,627,217	137,784,903
Other Property and Equipment	3,119,612	2,988,641
Total Property and Equipment	862,089,743	706,968,865
Less - Accumulated Depreciation and Depletion	81,672,508	63,265,919
Total Property and Equipment, Net	780,417,235	643,702,946
DEBT ISSUANCE COSTS	3,633,570	1,386,201
TOTAL ASSETS	$869,807,816	$725,593,919
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Accounts Payable	$114,864,432	$110,133,286
Accrued Expenses	1,112,942	131,012
Derivative Liability	14,916,895	9,363,068
Other Liabilities	28,585	33,229
Total Current Liabilities	130,922,854	119,660,595
LONG-TERM LIABILITIES		
Revolving Credit Facility	177,500,000	69,900,000
Derivative Liability	6,284,680	2,574,903
Other Noncurrent Liabilities	1,112,271	959,366
Deferred Tax Liability	43,941,000	35,929,000
Total Long-Term Liabilities	228,837,951	109,363,269
TOTAL LIABILITIES	359,760,805	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, (3/31/2012 - 63,503,852 Shares Outstanding and 12/31/2011 – 63,330,421 Shares Outstanding)	63,504	63,330
Additional Paid-In Capital	452,806,912	448,198,350
Retained Earnings	57,176,595	48,370,684
Accumulated Other Comprehensive Loss	-	(62,309)
Total Stockholders' Equity	510,047,011	496,570,055
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$869,807,816	$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 OPERATIONS AND COMPREHENSIVE INCOME (LOSS)
FOR THE THREE MONTHS ENDED MARCH 31, 2012 AND 2011
(UNAUDITED)

	Three Months Ended March 31, 2012	Three Months Ended March 31, 2011
REVENUES		
Oil and Gas Sales	$65,139,396	$27,041,621
Loss on Settled Derivatives	(5,335,597)	(3,262,056)
Loss on Mark-to-Market of Derivative Instruments	(9,364,913)	(21,278,629)
Other Revenue	84,106	25,813
Total Revenue	50,522,992	2,526,749
OPERATING EXPENSES		
Production Expenses	6,513,348	2,016,356
Production Taxes	6,078,885	2,615,864
General and Administrative Expense	4,681,378	3,290,589
Depletion of Oil and Gas Properties	18,309,500	6,863,479
Depreciation and Amortization	97,089	68,313
Accretion of Discount on Asset Retirement Obligations	15,632	4,730
Total Expenses	35,695,832	14,859,331
INCOME (LOSS) FROM OPERATIONS	14,827,160	(12,332,582)
OTHER (EXPENSE) INCOME		
Interest Expense	(196,299)	(120,642)
Interest Income	400	427,685
Gain on Available for Sale Securities	-	459,997
Total Other Income (Expense)	(195,899)	767,040
INCOME (LOSS) BEFORE INCOME TAXES	14,631,261	(11,565,542)
INCOME TAX PROVISION (BENEFIT)	5,825,350	(4,507,700)
NET INCOME (LOSS)	$8,805,911	$(7,057,842)
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX		
Unrealized Losses on Marketable Securities (Net of Tax of $295,000 at March 31, 2011)	$-	$(456,915)
Reclassification of Derivative Instruments Included in Income (Net of Tax of $39,000 and $101,000 for the Three Months Ended March 31, 2012 and 2011, Respectively)	62,309	169,150
Total Other Comprehensive Income (Loss)	$62,309	$(287,765)
COMPREHENSIVE INCOME (LOSS)	$8,868,220	$(7,345,607)
Net Income (Loss) Per Common Share - Basic	$0.14	$(0.11)
Net Income (Loss) Per Common Share - Diluted	$0.14	$(0.11)

Weighted Average Shares Outstanding - Basic	62,239,237	63,000,113
Weighted Average Shares Outstanding - Diluted	62,670,156	63,000,113

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

NORTHERN OIL AND GAS, INC.
STATEMENTS OF CASH FLOWS
FOR THE THREE MONTHS ENDED MARCH 31, 2012 AND 2011
(UNAUDITED)

	Three Months Ended March 31, 2012	Three Months Ended March 31, 2011
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income (Loss)	$8,805,911	$(7,057,842)
Adjustments to Reconcile Net Income (Loss) to Net Cash Provided by (Used for) Operating Activities:		
Depletion of Oil and Gas Properties	18,309,500	6,863,479
Depreciation and Amortization	97,089	68,313
Amortization of Debt Issuance Costs	148,687	89,392
Accretion of Discount on Asset Retirement Obligations	15,632	4,730
Deferred Income Taxes	5,820,000	(4,510,000)
Net Gain on Sale of Available for Sale Securities	-	(459,998)
Unrealized Loss on Derivative Instruments	9,364,913	21,278,629
Amortization of Deferred Rent	(8,308)	(4,644)
Share - Based Compensation Expense	2,204,927	1,858,171
Changes in Working Capital and Other Items:		
Increase in Trade Receivables	(9,946,705)	(4,993,687)
Increase in Prepaid Expenses	(508,724)	(50,779)
Increase in Other Current Assets	(72,196)	(277,694)
Increase (Decrease) in Accounts Payable	3,400,776	(19,968,628)
Increase (Decrease) in Accrued Expenses	981,930	(263)
Net Cash Provided By (Used For) Operating Activities	38,613,432	(7,160,821)
CASH FLOWS FROM INVESTING ACTIVITIES		
Purchase of Oil and Gas Properties and Development Capital Expenditures	(144,975,919)	(59,167,274)
Advances to Operators	-	(2,125,069)
Proceeds from Sale of Available for Sale Securities	-	32,949,813
Purchase of Available for Sale Securities	-	(18,381,690)
Purchases of Other Equipment and Furniture	(130,971)	(20,500)
Net Cash Used For Investing Activities	(145,106,890)	(46,744,720)
CASH FLOWS FROM FINANCING ACTIVITIES		
Advances on Revolving Credit Facility	262,600,000	-
Repayments on Revolving Credit Facility	(155,000,000)	-
Debt Issuance Costs Paid	(2,396,056)	-
Repurchase of Common Stock	(1,173,315)	-
Proceeds from Exercise of Stock Options	18,130	-
Proceeds from Exercise of Warrants	-	1,500,000
Net Cash Provided by Financing Activities	104,048,759	1,500,000
NET DECREASE IN CASH AND CASH EQUIVALENTS	(2,444,699)	(52,405,541)
CASH AND CASH EQUIVALENTS – BEGINNING OF PERIOD	6,279,587	152,110,701

CASH AND CASH EQUIVALENTS – END OF PERIOD	$3,834,888	$99,705,160
Supplemental Disclosure of Cash Flow Information		
Cash Paid During the Period for Interest	$750,624	$-
Cash Paid During the Period for Income Taxes	$5,350	$2,300
Non-Cash Financing and Investing Activities:		
Payment of Compensation through Issuance of Common Stock	$5,763,921	$7,374,660
Capitalized Asset Retirement Obligations	$140,937	$85,141
Non-Cash Compensation Capitalized on Oil and Gas Properties	$3,558,994	$5,516,489

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

NOTES TO UNAUDITED FINANCIAL STATEMENTS
MARCH 31, 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 Amex Equities 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 March 31, 2012, approximately 37% of our 174,248 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 $97,089 and $68,313 for the three months ended March 31, 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 months ended March 31, 2012 and 2011, respectively.

	Three Months Ended March 31,	
	2012	2011
Capitalized Certain Payroll and Other Internal Costs	$4,204,439	$5,940,025
Capitalized Interest Costs	1,010,974	-
Total	$5,215,413	$5,940,025

As of March 31, 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. There were no proceeds from property sales in the three months ended March 31, 2012 and 2011.

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 as determined by independent petroleum engineers. 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 March 31, 2012 and 2011, the Company transferred into the full cost pool costs related to expired leases of $1.9 million and $3.1 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 March 31, 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 has issuance costs related to the revolving credit facility (see Note 4) of $5.1 million. The debt issuance costs are being amortized over the term of the credit facility.

The amortization of debt issuance costs for the three months ended March 31, 2012 and 2011 was $148,687 and $89,392, 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 March 31, 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 March 31, 2012 and December 31, 2011.

Net Income (Loss) Per Common Share

Basic earnings per share ("EPS") are computed by dividing net income (loss) (the numerator) by the weighted average number of common shares outstanding for the period (the denominator). Diluted EPS is computed by dividing net income (loss) 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 months ended March 31, 2012 and 2011 are as follows:

	Three Months Ended March 31,	
	2012	2011
Weighted average common shares outstanding – basic	62,239,237	63,000,113
Plus: Potentially dilutive common shares		
Stock options, warrants, and restricted stock	430,919	-
Weighted average common shares outstanding – diluted	62,670,156	63,000,113
Restricted stock excluded from EPS due to the anti-dilutive effect	9,632	246,871

As of March 31, 2012 and 2011, potentially dilutive shares from stock options were 258,963 and 265,963, respectively. As of March 31, 2011, the 265,963 potentially dilutive shares from stock options were not included in the computation of diluted shares because they would be anti- dilutive due to the net loss during the period.

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 loss on settled derivatives and unrealized gains or losses are recorded to loss on mark-to-market of derivative instruments on the statements of operations and comprehensive income (loss) 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 is 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 is delivered. If the Company determines that it is probable that a hedged forecasted transaction will not occur, deferred gains or losses on the derivative are 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 March 31, 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 operations and comprehensive income (loss) 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 borrowings and the issuance of equity securities. At March 31, 2012, approximately $107.4 million of capital expenditures were in accounts payable.

Acquisitions

For the three months ended March 31, 2012, the Company acquired approximately 10,278 net mineral acres, for an average cost of $1,672 per net acre, in its key prospect areas in the form of effective leases.

For the three months ended March 31, 2011, the Company acquired approximately 11,514 net mineral acres, for an average cost of $1,601 per net acre, in its key prospect areas in the form of effective leases.

Unproved Properties

Unproved properties not being amortized comprise approximately 110,000 net acres and 117,000 net acres of undeveloped leasehold interests at March 31, 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 158 gross (16.5 net) wells drilling, awaiting completion or completing as of March 31, 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 March 31, 2012 and December 31, 2011, the amount of capitalized costs excluded from depletion were $141.6 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 described below.

As of March 31, 2012, the Company was participating in three defined drilling projects covering an aggregate of approximately 18,500 net acres of leasehold interests held by the Company. The Windsor project area includes approximately 2,700 net acres held by the Company, primarily located in Mountrail and surrounding counties of North Dakota. The South West Big Sky project includes approximately 4,500 total net acres held by the Company in Richland County, Montana. The Lambert project includes approximately 11,300 net acres held by the Company in Richland and Dawson Counties, Montana.

NOTE 4 REVOLVING CREDIT FACILITY

Credit Facility

On February 28, 2012, the Company entered into an amended and restated revolving bank 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 an initial commitment equal to the lesser of the facility amount or the borrowing base. At March 31, 2012, the facility amount was $750 million, the borrowing base was $250 million and there was an outstanding balance of $177.5 million, leaving $72.5 million of borrowing capacity available under the facility. Under the terms of the Revolving Credit Facility, the Company can issue up 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 bank 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 March 31, 2012, the commitment fee was 0.50% and the interest rate margin was 2.25% on LIBOR loans and 1.25% 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 bank credit facility at March 31, 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.

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 three months ended March 31, 2012 and the year ended December 31, 2011:

	Three Months Ended March 31, 2012	Year Ended December 31, 2011
Beginning balance	63,330,421	62,129,424
Stock based compensation	52,640	161,628
Stock options exercised	3,500	3,500
Restricted stock grants (Note 6)	343,548	786,263
Warrants exercised	-	300,000
Other Surrenders	(226,257)	(50,394)
Ending balance	63,503,852	63,330,421

2012 Activity

In the three months ended March 31, 2012, the Company issued 52,640 shares of common stock in aggregate to executives and employees of the Company as compensation for their services. The shares were fully vested on the date of grant. The fair value of the stock issued was approximately $1.3 million. The value of the stock was between $20.74 and $24.89 per share, the market value of the shares of common stock on the date the stock was issued. The Company expensed approximately $453,000 in share-based compensation related to these fully vested shares in the three months ended March 31, 2012. The remainder of fair value was capitalized into the full cost pool.

In January 2012, a director of the Company exercised 3,500 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 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 our business plan and completion of key projects.

For the quarter ended March 31, 2012, the Company had accrued bonuses of approximately $750,000 based on the year to date results of operations in comparison to year-end bonus performance goals. During the three months ended March 31, 2012, the Company expensed approximately $325,000 in compensation related to this bonus accrual and capitalized the remaining $425,000 into the full cost pool. The Company had accrued bonuses of approximately $437,000 for the three months ended March 30, 2011, approximately $121,000 were expensed in share-based compensation for the three months ended March 30, 2011 and the remaining $316,000 was capitalized 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 three months ended March 31, 2012, the Company issued 343,548 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 October 2014. As of March 31, 2012, there was approximately $20.8 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 three months ended March 31, 2012:

	Three Months Ended March 31, 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	343,548		24.65
Shares Forfeited	(179,117)		15.08
Lapse of Restrictions	(139,084)		21.68
Restricted Shares Outstanding at March 31, 2012	1,242,339	$	21.68

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 March 31, 2012, options to purchase a total of 258,963 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 three months ended March 31, 2012 under the 2006 Stock Option Plan or the 2009 Equity Incentive Plan. All exercises of options as of March 31, 2012 relate to the 2007 grants.

Currently Outstanding Options

- No options were forfeited in the three months ended March 31, 2012.
- No options expired during the three months ended March 31, 2012.
- Options covering 258,963 shares are exercisable and outstanding at March 31, 2012.
- There is no further compensation expense that will be recognized in future periods relative to any options that had been granted as of March 31, 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 March 31, 2012.
- There were no unvested options at March 31, 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 three month period ended March 31, 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.

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 (benefit) for the three months ended March 31, 2012 and 2011 consists of the following:

	Three Months Ended March 31,	
	2012	2011
Current Income Taxes	$5,350	$2,300
Deferred Income Taxes		
Federal	5,120,000	(3,645,000)
State	700,000	(865,000)
Total Provision (Benefit)	$5,825,350	$(4,507,700)

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 months ended March 31, 2012 and 2011, the Company did not recognize any interest or penalties in its statements of operations and comprehensive income (loss), nor did it have any interest or penalties accrued in its balance sheet at March 31, 2012 and December 31, 2011 relating to unrecognized benefits.

The tax years 2011, 2010, 2009 and 2008 remain open to examination for federal income tax purposes and by the other major taxing jurisdictions to which the Company is subject.

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 March 31, 2012 and December 31, 2011.

	Fair Value Measurements at March 31, 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 Liability (crude oil swaps and collars)	$-	$(14,916,895)	$ -
Commodity Derivatives – Non-Current Liability (crude oil swaps and collars)	-	(6,284,680)	-
Credit Facility – Long Term Liability		(177,500,000)	-
Total	$-	$(198,701,575)	$ -

	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)	-
Credit Facility – Long Term Liability	-	(69,900,000)	-
Total	$-	$(81,837,971)	$ -

There were no transfers of financial assets or liabilities between Level 1 and Level 2 inputs for the three month period ended March 31, 2012.

Level 2 liabilities consist of derivative liabilities (see Note 12) and our Credit Facility (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 liability amounts represent the fair values expected to be settled in the subsequent year. Fair value of the Company's credit facility was based on discounted future cash flows and current market interest rates.

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 three month period ended March 31, 2012.

NOTE 11 FINANCIAL INSTRUMENTS

The Company's non-derivative financial instruments include cash and cash equivalents, accounts receivable, accounts payable, and credit facility and are not measured at fair value on the balance sheets. The carrying amount of these non-derivative financial instruments approximate 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 March 31, 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 March 31, 2012 and December 31, 2011. As of March 31, 2012, outstanding derivative contracts with commercial banks participating in the Company's 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 Company's 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 loss on settled derivatives and unrealized gains or losses are recorded to gain (loss) on mark-to-market of derivative instruments on the statement of operations and comprehensive income (loss) rather than as a component of other comprehensive income (loss) or other income (expense).

The Company has a master netting agreement on each of the individual crude oil contracts and therefore the current asset and liability are netted on the balance sheet and the non-current asset and liability are netted on the balance sheet.

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 operations and comprehensive income (loss). 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 March 31, 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.

Crude Oil Derivative Contracts Cash-flow Not Designated as Hedges

The Company realized a loss on settled derivatives of $5,335,597 and $3,262,056 and a loss on mark-to-market of derivative instruments of $9,364,913 and $21,278,629 for three months ended March 31, 2012 and 2011, respectively.

The following table reflects open commodity swap contracts as of March 31, 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			
04/01/12 – 6/30/12	69,000	80.00	103.63
04/01/12 – 6/30/12	96,000	81.50	103.64
04/01/12 – 6/30/12	30,000	85.50	103.64
04/01/12 – 12/31/12	325,000	95.15	104.84
04/01/12 – 12/31/12	180,000	100.00	104.53
01/01/14 – 6/30/14	240,000	100.00	100.00

As of March 31, 2012, the Company had a total volume on open commodity swaps of 940,000 barrels at a weighted average price of approximately $94.50.

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 March 31, 2012.

Term	Oil (Barrels)		Price	Basis
Costless Collars				
04/01/12 – 12/31/12	101,333	$	85.00/$95.25	NYMEX
01/01/13 – 12/31/13	760,794	$	85.00/$98.00	NYMEX
04/01/12 – 12/31/13	327,808	$	90.00/$103.50	NYMEX
04/01/12 – 12/31/13	318,640	$	90.00/$106.50	NYMEX
04/01/12 – 12/31/13	459,968	$	90.00/$110.00	NYMEX
04/01/12 – 12/31/13	440,847	$	95.00/$107.00	NYMEX
07/01/12 – 12/31/12	120,000	$	95.00/$115.10	NYMEX
01/01/13 – 12/31/13	480,000	$	95.00/$110.70	NYMEX

At March 31, 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		March 31, 2012 Estimated Fair Value		December 31, 2011 Estimated Fair Value
Derivative Assets:					
Swap Contracts	Current liabilities	$	-	$	285,126
Swap Contracts	Non-current liabilities		73,661		-
Costless Collars	Current liabilities		5,140,785		1,932,884
Costless Collars	Non-current liabilities		9,750,745		8,766,484
Total Derivative Assets		$	14,965,191	$	10,984,494
Derivative Liabilities:					

Swap Contracts	Current liabilities	$ (8,264,098)	$ (8,383,588)
Swap Contracts	Non-current liabilities	(78,625)	-
Costless Collars	Current liabilities	(11,793,582)	(3,197,490)
Costless Collars	Non-current liabilities	(16,030,461)	(11,341,387)
Total Derivative Liabilities		(36,166,766)	$ (22,922,465)

The following disclosures are applicable to the Company's financial statements, as of March 31, 2012 and 2011, respectively:

		Amount of Loss Reclassified from AOCI into Income	
Derivative Type	Location of Loss for Effective and Ineffective Portion of Derivative In Income	Three Months Ended March 31, 2012	Three Months Ended March 31, 2011
Commodity - Cash Flow	Loss on Settled Derivatives	$ 101,309	$ 270,150

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

NOTE 13 SUBSEQUENT EVENTS

In connection with preparing the unaudited financial statements for the three months ended March 31, 2012, the Company has evaluated subsequent events for potential recognition and disclosure through the date of this filing and determined that there were no subsequent events which required recognition or disclosure in the financial statements.

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), 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, primarily in the Bakken and Three Forks formations within the Williston Basin in North Dakota and Montana. 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 to 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 first quarter of 2012 was approximately 8,517 Boe per day, of which approximately 93% was oil. Our first quarter 2012 average daily production increased 115% year-over-year, as compared to an average of 3,962 Boe per day in the first quarter of 2011. As of March 31, 2012, we participated in 793 gross (71.8 net) producing wells.

As of March 31, 2012, we leased approximately 646,522 gross (174,248 net) acres, of which 645,455 gross (173,171 net) acres, over 99%, were located in the Williston Basin of North Dakota and Montana. In 2011, we acquired approximately 43,239 net mineral acres at an average cost of approximately $1,832 per net acre. During the quarter ended March 31, 2012, we acquired approximately 10,278 net mineral acres at an average cost of approximately $1,672 per net acre.

Highlights from First Quarter 2012 Results

During the three months ended March 31, 2012, we achieved the following financial and operating results:

- Including the effect of realized gains (losses) from derivative contracts, oil, gas and NGL sales increased 151% for the three month period ended March 31, 2012 as compared to the same period last year;
- Average daily production reached 8,517 Boe per day;
- Participated in the completion of 129 gross (13.9 net) wells, with a 100% success rate in the Bakken and Three Forks plays;
- Entered into additional derivative contracts for 2012, 2013 and 2014; and
- Increased our borrowing base from $120 million to $250 million.

Total oil, gas, and NGL sales increased 141% for the first quarter of 2012 compared to the same period in 2011. This increase was due to higher production levels resulting from 13.9 net wells added during the first quarter of 2012. Average realized prices on a per Boe basis (including realized gains (losses) from derivative contracts) were 16% higher in the first quarter 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 hedging 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

- 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 mark-to-market of 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 under our revolving credit facility. As a result, we incur interest expense that is affected by both fluctuations in interest rates and our financing decisions. We capitalize interest paid to the lenders under our revolving credit facility into our full cost pool. We include 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 differentials between the NYMEX WTI and the sales prices we receive for our oil production. Higher oil differentials lowered our oil and gas sales in the first quarter 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 differentials to increase for a short period during the first quarter, 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 differentials will return to historical levels. Our oil price differential to the NYMEX WTI benchmark price during the first quarter of 2012 was $14.09 per barrel, as compared to $9.34 per barrel in the first quarter of 2011.

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 natural gas, natural gas liquids ("NGLs") and oil that we produce significantly impact our revenues and cash flows. Commodity prices have been volatile in recent years. The following table lists average New York Mercantile Exchange ("NYMEX") prices for natural gas and oil for the three months ended March 31, 2012 and 2011.

	Three Months Ended March 31, 2012	Three Months Ended March 31, 2011
Average NYMEX prices(a)		
Natural gas (per mcf)	$2.50	$4.20
Oil (per bbl)	$103.03	$94.60

(a) Based on average NYMEX closing prices.

Results of Operations for the periods ended March 31, 2012 and March 31, 2011

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

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	Three Months Ended March 31, 2012	2011	% Change
Net Production:			
Oil (Bbl)	717,518	335,241	114 %
Natural Gas (Mcf)	345,427	128,286	169
Total (Boe)	775,089	356,622	117
Net Sales:			
Oil Sales	$62,674,342	$26,247,102	139
Natural Gas Sales	2,465,054	794,519	210
Loss on Settled Derivatives	(5,335,597)	(3,262,056)	(64)
(Loss) on Mark-to-Market of Derivative Instruments	(9,364,913)	(21,278,629)	56
Other Revenue	84,106	25,813	226
Total Revenues	50,522,992	2,526,749	1900
Average Sales Prices:			
Oil (per Bbl)	$87.35	$78.29	12
Effect of Loss on Settled Derivatives on Average Price (per Bbl)	(7.44)	(9.73)	(24)
Oil Net of Settled Derivatives (per Bbl)	79.91	68.56	17
Natural Gas and other liquids (per Mcf)	7.14	6.19	15
Realized price on a Boe basis including all realized derivative settlements	77.16	66.68	16
Operating Expenses:			
Production Expenses	$6,513,348	$2,016,356	223
Production Taxes	6,078,885	2,615,864	132
General and Administrative Expense (Including Share Based Compensation)	4,681,378	3,290,589	42
General and Administrative Expense (Non-Cash Share Based Compensation)	2,204,927	1,858,171	19
Depletion of Oil and Gas Properties	18,309,500	6,863,479	167
Costs and Expenses (per Boe):			
Production Expenses	$8.40	$5.65	49
Production Taxes	7.84	7.34	7
General and Administrative Expense (Including Share Based Compensation)	6.04	9.23	(35)
General and Administrative Expense (Non-Cash Share Based Compensation)	2.84	5.21	(45)
Depletion of Oil and Gas Properties	23.62	19.25	23
Net Producing Wells at Period End	71.8	31.0	132

Oil and Gas Sales

In the first quarter of 2012, oil, natural gas and NGL sales increased 141% as compared to the first quarter of 2011, driven primarily by a 117% increase in production and partially aided by a 16% increase in realized prices taking into account the effect of settled derivatives. Partially offsetting the higher average realized price in the first quarter of 2012 as compared to the same period in 2011 was a higher oil differential. Oil differential during the first quarter of 2012 was $14.09 per barrel, as compared to $9.34 per barrel in the first 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 first quarter of 2012, our average daily production volumes increased 115% as compared to the first quarter of 2011. The production primarily increased due to the addition of more net productive wells in 2012 as compared to 2011.

Derivative Instruments

For the three months ended March 31, 2012, we incurred a loss on settled derivatives of $5.3 million, compared to $3.3 million loss for the three month period ended March 31, 2011. Our average realized price (including all derivative settlements) received during the first quarter of 2012 was $77.16 per Boe compared to $66.68 per Boe in the first quarter of 2011. Our average realized price (including all derivative settlements) calculation includes all cash settlements for derivatives.

We had mark-to-market derivative losses of $9.4 million in the first quarter of 2012 compared to a $21.3 million loss in the first quarter of 2011. At March 31, 2012, all of our derivative contracts were recorded at their fair value, which was a net liability of $21.2 million, a decrease of $16.0 million from the $37.2 million net liability recorded as of March 31, 2011.

Production Expenses

Production expenses were $6.5 million in the first quarter of 2012 compared to $2.0 million in the first 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 per Boe increased from $5.65 per barrel sold in the first quarter of 2011 to $8.40 in first quarter of 2012. The increase was related to higher operating costs in our Williston Basin activities. The largest cost driver in our Williston Basin operations is the disposal of water. On an absolute dollar basis, our production expenses in the first quarter of 2012 were 223% higher when compared to the same quarter in 2011 due to production levels increasing 117%, higher water hauling and disposal costs and workover expenses.

Production Taxes

We pay production taxes based on realized crude oil and natural gas sales. These costs were $6.1 million in the first quarter of 2012 compared to $2.6 million in the first quarter of 2011. As a percent of oil and gas sales, our production taxes were 9.3% and 9.7% in 2012 and 2011, respectively. The 2012 average production tax rate was lower than the 2011 average due to well additions that qualified for reduced rates/or tax exemptions during 2012. Certain 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 $4.7 million for the first quarter of 2012 compared to $3.3 million for the first quarter of 2011. The 2012 increase of $1.4 million when compared to 2011 was due to higher base salaries and benefits ($0.5 million), increased share based compensation expense ($0.3 million), travel expenses ($0.1 million) and higher legal and professional expenses ($0.2 million). As a result of our growth, we increased staffing in the legal, finance and land departments. Our personnel costs continue to increase as we invest in our technical teams and other staffing to support our growth. Share based compensation expense represents the amortization of restricted stock grants granted to our employees and directors as part of compensation as well as fully vested share grants to employees and directors throughout the year.

Depletion, Depreciation and Amortization

Depletion, depreciation and amortization ("DD&A") was $18.4 million in the first quarter of 2012 compared to $6.9 million in the first quarter of 2011. Depletion expense, the largest component of DD&A, was $23.62 per Boe in the first quarter of 2012 compared to $19.25 per Boe in the first quarter of 2011. The aggregate increase in depletion expense for 2012 compared to 2011 was driven by a 117% increase in production. Additionally, depletion rates rose in 2012 due to an increase in our future development 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 $0.1 million in first quarter of 2012 compared to $73,043 in the first quarter of 2011.

The following table summarizes DD&A expense per Boe for the first quarters of 2012 and 2011:

	Three Months Ended March 31,			
	2012	2011	Change	Change
Depletion	$23.62	$19.25	$4.38	23 %
Depreciation, amortization, and accretion	0.15	0.20	(0.05)	(25 %)
Total DD&A expense	$23.77	$19.45	$4.32	22 %

Interest Expense

Interest expense, net of capitalized interest, was $0.2 million for the first quarter of 2012 compared to $0.1 million in the first quarter of 2011. The increase in interest expense between periods was not significant.

Interest Income

During the first quarter of 2012 we had no interest income as compared to $0.4 million in the first quarter of 2011. Interest income for 2012 decreased $0.4 million as compared to 2011 because of lower levels of cash and short term investments. The higher amount of cash and short term investments in the first quarter of 2011 resulted from the sale of common stock in November 2010.

Income Tax Provision

The provision for income taxes was $5.8 million in the first quarter of 2012 compared to a benefit of $4.5 million in the first quarter of 2011. The effective tax rate in 2012 was 39.8% compared to an effective tax rate of 38.9% in 2011. The $21.3 million mark-to-market losses on derivative instruments was the primary reason for pre-tax losses during the first quarter of 2011. Additionally, 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 of 4.8% and (4.9)% in 2012 and 2011, respectively.

Non-GAAP Financial Measures

Our non-GAAP net income, which excludes unrealized mark-to-market derivative gains and losses net of tax, for the first quarter of 2012 was $14.4 million (representing approximately $0.23 per diluted share) as compared to our non-GAAP net income, which excludes unrealized mark-to-market hedging gains and losses net of tax of $5.9 million (representing approximately $0.09 per diluted share) for the first quarter of 2011. The increase in non-GAAP net income is 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 first quarter of 2012 was $44.8 million, compared to Adjusted EBITDA of $18.6 million for the first quarter of 2011. The increase in Adjusted EBITDA is 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.

The non-GAAP financial information is presented using consistent methodology from year to year. 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.

Net income excluding unrealized mark-to-market derivative gains and losses and Adjusted EBITDA are non-GAAP measures. A reconciliation of these measures to GAAP is included below:

NORTHERN OIL AND GAS, INC.
Reconciliation of Net Income to Non-GAAP Net Income Excluding
Unrealized Gain (Loss) on Derivative Instruments
(UNAUDITED)

	Three Months Ended March 31	
	2012	2011
Net Income (Loss)	$8,805,911	$(7,057,842)
Add:		
Unrealized Gain (Loss) on Derivative Instruments	9,364,913	21,278,629
Tax Impact	(3,727,000)	(8,299,000)
Net Income without Effect of Certain Items	$14,443,824	$5,921,787
Weighted Average Shares Outstanding - Basic	62,239,237	63,000,113
Weighted Average Shares Outstanding - Diluted	62,670,156	63,246,984
Net Income (Loss) Per Common Share - Basic	$0.14	$(0.11)
Add:		
Change due to Unrealized Gain (Loss) on Derivative Investments	0.15	0.34
Change due to Tax Impact	(0.06)	(0.14)
Net Income without Effect of Certain Items Per Common Share - Basic	$0.23	$0.09
Net Income (Loss) Per Common Share - Diluted	$0.14	$(0.11)
Add:		
Change due to Mark-to-Market of Derivative Investments	0.15	0.34
Change due to Tax Impact	(0.06)	(0.14)
Net Income without Effect of Certain Items Per Common Share - Diluted	$0.23	$0.09

Northern Oil and Gas, Inc.
Reconciliation of Adjusted EBITDA

	Three Months Ended March 31, 2012	Three Months Ended March 31, 2011
Net Income (Loss)	$ 8,805,911	$ (7,057,842)
Add:		
Interest Expense	196,299	120,642
Income Tax Provision (Benefit)	5,825,350	(4,507,700)
Depreciation, Depletion, Amortization, and Accretion	18,422,221	6,936,522
Non-Cash Share Based Compensation	2,204,927	1,858,171
Unrealized (Gain) Loss on Derivative Instruments	9,364,913	21,278,629
Adjusted EBITDA	$ 44,819,621	$ 18,628,422

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 our senior secured revolving credit facility to increase the maximum facility size to $750 million and the borrowing base to $250 million. Under the terms of the revolving credit facility, the borrowing base will be reduced by 25% of the stated amount of any permitted additional indebtedness (as defined in the credit agreement) that we incur.

At March 31, 2012, our debt to total capitalization ratio was 26%, we had $177.5 million of debt outstanding, $510.0 million of stockholders' equity, and $3.8 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 operation 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 oil 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 three month periods ended March 31, 2012 and 2011 are presented below:

Three Months Ended

	March 31,	
	2012	2011
	(In thousands, unaudited)	
Net cash (used for) provided by operating activities	$ 38,613	$ (7,161)
Net cash used in investing activities	(145,107)	(46,745)
Net cash provided by financing activities	104,049	1,500
Net change in cash	$ (2,445)	$ (52,406)

Cash flows provided by operating activities

Net cash provided by operating activities for the three months ended March 31, 2012 was $38.6 million compared to $7.2 million used in operations during the three months ended March 31, 2011. This increase was due to higher production from development activity and higher realized prices, 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 (as reflected in our statements of cash flows) in the three months ended March 31, 2012 was a decrease of $6.1 million compared to a decrease of $25.3 million in the same period of the prior year.

Cash flows used in investing activities

We had cash flows used in investing activities of $145.1 million and $46.7 million during the three month periods ended March 31, 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 quarter 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 quarter of 2012, we added 13.9 net producing wells compared to approximately 5.0 net producing wells during the first quarter of 2011. At March 31, 2012 we were drilling or awaiting completion on 16.5 net wells.

Cash flows provided by financing activities

Net cash provided by financing activities was $104.0 million and $1.5 million during the three months ended March 31, 2012 and 2011, respectively. For the three months ended March 31, 2012, we received $107.6 million in net advances under our revolving credit facility that were used to fund drilling, development and acquisition costs.

Revolving Credit Facility

As of December 31, 2011, we maintained a $500 million revolving credit facility that is secured by substantially all of our assets with a maturity of May 26, 2014. We had $69.9 million of borrowings under this 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 this facility.

On February 28, 2012, we entered into an amended and restated 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 closing, the facility amount was $750 million and provided for a $250 million borrowing base. Under the terms of the revolving credit facility, we can issue up to $300 million of permitted additional indebtedness, as defined in the revolving credit agreement. The borrowing base is reduced by 25% of the stated amount of the permitted additional indebtedness. The new credit facility provides for a borrowing base subject to redetermination semi-annually each April and October and for event-driven unscheduled redeterminations. The new bank group is comprised of a group of commercial banks, with no single bank holding more than 14% of the total facility. As of March 31, 2012, the outstanding balance under the credit facility was $177.5 million leaving $72.5 million of borrowing capacity available under the facility. The loan matures on January 1, 2017. Borrowings under the bank 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 0.375% to 0.50%. The facility contains 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 credit facility at March 31, 2012.

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. During 2011, we spent approximately $300 million on drilling projects and approximately $80 million on acreage acquisitions located in the Williston Basin. Our 2011 capital program was funded by cash reserves, cash from operations and borrowings under our credit facility. Based on our current understanding of our operators' development plans for 2012, we expect that our total capital expenditures in 2012 for drilling and completion of wells will be approximately $360 million and we expect to spend an additional $60 million to $80 million in connection with acreage acquisitions. As of March 31, 2012, we had spent approximately $150 million of our capital budget for 2012 and we were participating in 158 gross (16.5 net) wells that were being actively drilled or awaiting completion.

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 ranges from approximately $7 to $9 million per well, and can vary based on vertical depth of the well, lateral length and completion techniques.

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 competitors, 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.

Contractual Obligations and Commitments

Our material long-term debt obligations, capital lease obligations and operating lease obligations or purchase obligations are included in Item 7 of our Annual Report on Form 10-K for the fiscal year ended December 31, 2011, and have not materially changed since that report was filed.

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 and natural gas 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 gains or losses are recorded to gain (loss) on mark-to-market of 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 oil 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 March 31, 2012, we had entered into derivative agreements covering 2.4 million barrels for 2012, 1.9 million barrels for 2013 and 0.2 million barrels for 2014.

The following table summarizes the oil derivative contracts that we have entered into for each year as of March 31, 2012:

Contract Type	Volume Hedged (Bbl)	West Texas Intermediate Strike Price ($/Bbl)	Term
Collar	141,877	$85.00/$95.25	Jan 1 - Dec 31, 2012
Collar	271,216	$90.00/$103.50	Jan 1 - Dec 31, 2012
Collar	241,820	$90.00/$106.50	Feb 1 - Dec 31, 2012
Collar	269,296	$90.00/$110.00	Mar 1 - Dec 31, 2012
Collar	300,630	$95.00/$107.00	Mar 1 - Dec 31, 2012
Collar	120,000	$95.00/$115.10	Jul 1 - Dec 31, 2012
Swap	3,000	$51.25	Jan 1 - Feb 29, 2012
Swap	138,000	$80.00	Jan 1 - Jun 30, 2012
Swap	198,000	$81.50	

			Jan 1 - Jun 30, 2012
Swap	60,000	$85.50	Jan 1 - Jun 30, 2012
Swap	376,000	$95.15	Jan 1 - Dec 31, 2012
Swap	240,000	$100.00	Jan 1 - Dec 31, 2012
Swap	38,942	$101.00	Jan 1 - Jan 31, 2012
2012 Total/Average	2,398,781	$91.13	
Collar	760,794	$85.00/$98.00	Jan 1 - Dec 31, 2013
Collar	149,515	$90.00/103.50	Jan 1 - Dec 31, 2013
Collar	139,791	$90.00/$106.50	Jan 1 - Dec 31, 2013
Collar	224,900	$90.00/$110.00	Jan 1 - Dec 31, 2013
Collar	182,269	$95.00/$107.00	Jan 1 - Dec 31, 2013
Collar	480,000	$95.00/$110.70	Jan 1 - Dec 31, 2013
2013 Total/Average	1,937,269	$89.75	
Swap	240,000	$100.00	Jan 1 - Jun 30, 2014
2014 Total/Average	240,000	$100.00	

Interest Rate Risk

We had $177.5 million in outstanding borrowings at an average rate of 2.7% under our revolving credit facility as of March 31, 2012. 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 outstanding at March 31, 2012 would cost us approximately $1.8 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 the 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 March 31, 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 March 31, 2012.

Changes in Internal Control over Financial Reporting

No change in our Company's internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) occurred during the quarter ended March 31, 2012, that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II - OTHER INFORMATION

Item 1. Legal Proceedings.

On August 23, 2010, plaintiff Donald Rensch filed a shareholder derivative complaint (the “Original Complaint”) in the United States District Court for the District of Minnesota against our company as nominal defendant, Michael L. Reger, Ryan R. Gilbertson, James R. Sankovitz and Chad D. Winter, James Randall Reger, James Russell Reger, Weldon W. Gilbertson, Douglas M. Polinsky, Joseph A. Geraci, II and Voyager Oil & Gas, Inc. (“Voyager”). The Original Complaint alleged breach of fiduciary duty of loyalty and usurping of corporate opportunities by Messrs. M. Reger, Gilbertson, Sankovitz and Winter; asserted allegations against Messrs. James Randall Reger, Weldon W. Gilbertson, James Russell Reger, Douglas M. Polinsky and Joseph A. Geraci, II of aiding and abetting our officers in breaching their fiduciary duties and usurping of corporate opportunities in connection with the formation, capitalization, and operation of Plains Energy (Voyager’s predecessor); and asserted a claim against Voyager for tortious interference with a prospective business relationship. The plaintiff sought injunctive relief and damages, including imposing on Voyager and all of its assets a constructive trust for our company’s benefit. On June 20, 2011, the District Court granted a motion to dismiss the lawsuit, and the complaint was dismissed without prejudice.

On July 20, 2011, plaintiff Donald Rensch filed an amended shareholder derivative complaint (the “Amended Complaint”) in the same court against our company as nominal defendant, Michael L. Reger, Ryan R. Gilbertson, James R. Sankovitz and Voyager. All other defendants from the Original Complaint were not included as defendants in the Amended Complaint. The Amended Complaint alleges breach of fiduciary duty of loyalty and usurping of corporate opportunities by Messrs. Reger, Gilbertson and Sankovitz in connection with the formation, capitalization, and operation of Plains Energy (Voyager’s predecessor), and also includes related aiding and abetting claims against Voyager and Messrs. Reger and Gilbertson. The plaintiff seeks unspecified equitable relief and damages. We believe that each of the above claims lacks merit and intend to strongly defend our company and each of our current and/or former officers and directors in connection with this lawsuit. A motion to dismiss the lawsuit in the United States District Court for the District of Minnesota was filed on September 9, 2011. The motion was heard before the Court on December 20, 2011, but the Court has not yet issued a ruling on the motion.

In addition to the foregoing, 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.
Risks Related to Our Business

Oil and natural gas prices are volatile. A protracted period of depressed oil and natural gas prices could adversely affect our financial position, results of operations and cash flow.

The oil and natural gas markets are very volatile, and we cannot predict future oil and natural gas prices. The prices we receive for our oil and natural gas production heavily influences our revenue, profitability, access to capital and future rate of growth. The prices we receive for our production and the levels of our production depend on numerous factors beyond our control. These factors include, but are not limited to, the following:

- changes in global supply and demand for oil and natural gas;
- the actions of OPEC and other major oil producing countries;
- the price and quantity of imports of foreign oil and natural gas;

- political and economic conditions, including embargoes, in oil-producing countries or affecting other oil-producing activity;
- the level of global oil and natural gas exploration and production activity;
- the level of global oil and natural gas inventories;
- weather conditions;

- technological advances affecting energy consumption;
- domestic and foreign governmental regulations;
- proximity and capacity of oil and natural gas pipelines and other transportation facilities;
- the price and availability of competitors' supplies of oil and natural gas in captive market areas; and
- the price and availability of alternative fuels.

Lower oil and natural gas prices may not only decrease our revenues but also may reduce the amount of oil and natural gas that our operators can produce economically and therefore potentially lower our reserve bookings. A substantial or extended decline in oil or natural gas prices may result in impairments of our proved oil and natural gas properties and may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures. To the extent commodity prices received from production are insufficient to fund planned capital expenditures, we may be required to reduce spending or borrow or issue additional equity to cover any such shortfall. Lower oil and natural gas prices may also reduce the amount of our borrowing base under our revolving credit facility, which is determined at the discretion of the lenders based on the collateral value of our proved reserves that have been mortgaged to the lenders and is subject to redetermination from time to time as provided in our credit agreement.

Our estimated reserves are based on many assumptions that may prove to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

Determining the amount of oil and natural gas recoverable from various formations involves significant uncertainty. No one can measure underground accumulations of oil or natural gas in an exact way. Oil and natural gas reserve engineering requires subjective estimates of underground accumulations of oil and/or natural gas and assumptions concerning future oil and natural gas prices, production levels, and operating and development costs. Some of our reserve estimates are made without the benefit of a lengthy production history, and are less reliable than estimates based on a lengthy production history. As a result, estimated quantities of proved reserves and projections of future production rates and the timing of development expenditures may prove to be inaccurate.

We routinely make estimates of oil and natural gas reserves in connection with managing our business and preparing reports to our lenders and investors. We make these reserve estimates using various assumptions, including assumptions as to oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Some of these assumptions are inherently subjective, and the accuracy of our reserve estimates relies in part on the ability of our management team, reserve engineers and other advisors to make accurate assumptions. Any significant variance from these assumptions by actual figures could greatly affect our estimates of reserves, the economically recoverable quantities of oil, natural gas and NGLs attributable to any particular group of properties, the classifications of reserves based on risk of recovery, and estimates of the future net cash flows. Numerous changes over time to the assumptions on which our reserve estimates are based, as described above, often result in the actual quantities of oil, natural gas and NGLs we ultimately recover being different from our reserve estimates.

Drilling for and producing oil, natural gas and NGLs are high risk activities with many uncertainties that could adversely affect our financial condition or results of operations.

Our operators' drilling activities are subject to many risks, including the risk that they will not discover commercially productive reservoirs. Drilling for oil or natural gas can be uneconomical, not only from dry holes, but also from productive wells that do not produce sufficient revenues to be commercially viable. In addition, drilling and producing operations on our acreage may be curtailed, delayed or canceled by our operators as a result of other factors, including:

- the high cost, shortages or delivery delays of equipment and services;
- shortages of or delays in obtaining water for hydraulic fracturing operations;
- unexpected operational events;

- adverse weather conditions;
- facility or equipment malfunctions;
- title problems;
- pipeline ruptures or spills;
- compliance with environmental and other governmental requirements;
- unusual or unexpected geological formations;
- loss of drilling fluid circulation;
- formations with abnormal pressures;
- environmental hazards, such as oil, natural gas or well fluids spills or releases, pipeline or tank ruptures and discharges of toxic gas;
- fires;
- blowouts, craterings and explosions;
- uncontrollable flows of oil, natural gas or well fluids; and
- pipeline capacity curtailments.

Any of these events can cause substantial losses, including personal injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution, environmental contamination, loss of wells and regulatory penalties.

We ordinarily maintain insurance against various losses and liabilities arising from our operations; however, insurance against all operational risks is not available to us. Additionally, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the perceived risks presented. Losses could therefore occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. The occurrence of an event that is not fully covered by insurance could have a material adverse impact on our business activities, financial condition and results of operations.

If oil or natural gas prices decrease or drilling efforts are unsuccessful, we may be required to record writedowns of our oil and natural gas properties.

We could be required to write down the carrying value of certain of our oil and natural gas properties. Writedowns may occur when oil and natural gas prices are low, or if we have downward adjustments to our estimated proved reserves, increases in our estimates of operating or development costs, deterioration in drilling results or mechanical problems with wells where the cost to redrill or repair is not supported by the expected economics.

Accounting rules require that the carrying value of oil and natural gas properties be periodically reviewed for possible impairment. Impairment is recognized for the excess of book value over fair value when the book value of a proved property is greater than the expected undiscounted future net cash flows from that property and on acreage when conditions indicate the carrying value is not recoverable. We may be required to write down the carrying value of a property based on oil and natural gas prices at the time of the impairment review, or as a result of continuing evaluation of drilling results, production data, economics, divestiture activity, and other factors. While an impairment charge reflects our long-term ability to recover an investment, reduces our reported earnings and increases our leverage ratios, it does not impact cash or cash flow from operating activities.

Our future success depends on our ability to replace reserves that our operators produce.

Because the rate of production from oil and natural gas properties generally declines as reserves are depleted, our future success depends upon our ability to economically find or acquire and produce additional oil and natural gas reserves. Except to the extent that we acquire additional properties containing proved reserves, conduct successful exploration and development activities or, through engineering studies, identify additional behind-pipe zones or secondary recovery reserves, our proved reserves will decline as our reserves are produced. Future oil and natural gas production, therefore, is highly dependent upon our level of success in acquiring or finding additional reserves that are economically recoverable. We cannot assure you that we will be able to find or acquire and develop additional reserves at an acceptable cost.

We may acquire significant amounts of unproved property to further our development efforts. Development and exploratory drilling and production activities are subject to many risks, including the risk that no commercially productive reservoirs will be discovered. We acquire both proved and producing properties as well as undeveloped acreage that we believe will enhance growth potential and increase our earnings over time. However, we cannot assure you that all of these properties will contain economically viable reserves or that we will not abandon our initial investments. Additionally, we cannot assure you that unproved reserves or undeveloped acreage that we acquire will be profitably developed, that new wells drilled on our properties will be productive or that we will recover all or any portion of our investments in our properties and reserves.

As a non-operator, our development of successful operations relies extensively on third-parties, which could have a material adverse effect on our results of operation.

We have only participated in wells operated by third-parties. Our current ability to develop successful business operations depends on the success of our operators. If our operators are not successful in the development, exploitation, production and exploration activities relating to our leasehold interests, or are unable or unwilling to perform, our financial condition and results of operation would be materially adversely affected.

Our operators will make decisions in connection with their operations (subject to their contractual and legal obligations to other owners of working interests), which may not be in our best interests.

Additionally, we may have virtually no ability to exercise influence over the operational decisions of our operators, including the setting of capital expenditure budgets and drilling locations and schedules. Dependence on our operators could prevent us from realizing our target returns for those locations. The success and timing of development activities by our operators will depend on a number of factors that will largely be outside of our control, including:

- the timing and amount of capital expenditures;
- their expertise and financial resources;
- approval of other participants in drilling wells;
- selection of technology; and
- the rate of production of reserves, if any.

We could experience periods of higher costs as activity in the Williston Basin accelerates or if commodity prices rise. These increases could reduce our profitability, cash flow, and ability to complete development activities as planned.

Recently, major international oil and gas companies have publicly announced significant acquisition and joint venture transactions within the Williston Basin. This has resulted in increased activity and investment in the region. As activity in the Williston Basin increases, competition for equipment, labor and supplies is also expected to increase. Likewise, higher oil, natural gas and NGL prices generally increase the demand for equipment, labor and supplies, and can lead to shortages of, and increasing costs for, drilling equipment, services and personnel. Shortages of, or increasing costs for, experienced drilling crews and equipment and services could restrict our operating partners' ability to drill the wells and conduct the operations that we currently expect.

In addition, capital and operating costs in the oil and natural gas industry have generally risen during periods of increasing commodity prices as producers seek to increase production in order to capitalize on higher commodity prices. In situations where cost inflation exceeds commodity price inflation, our profitability and cash flow, and our operators’ ability to complete development activities as scheduled and on budget, may be negatively impacted. Any delay in the drilling of new wells or significant increase in drilling costs could reduce our revenues and cash available to make payments on our debt obligations.

Our lack of industry and geographical diversification may increase the risk of an investment in our company.

Our business focus is on the oil and natural gas industry in a limited number of properties that are primarily in the areas of the Williston Basin located in Montana and North Dakota. While other companies may have the ability to manage their risk by diversification, the narrow focus of our business, in terms of both the industry focus and geographic scope of our business, means that we will likely be impacted more acutely by factors affecting our industry or the region in which we operate than we would if our business were more diversified. As a result of the narrow industry focus of our business, we may be disproportionately exposed to the effects of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints, market limitations, weather events or interruption of the processing or transportation of oil or natural gas. Additionally, we may be exposed to further risks, such as changes in field-wide rules and regulations that could cause us to permanently or temporarily shut-in all of our wells within the Williston Basin. We do not currently intend to broaden either the nature or geographic scope of our business.

Locations that the operators of our properties decide to drill may not yield oil or natural gas in commercially viable quantities.

The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a well. Our efforts will be uneconomical if the operators of our properties drill dry holes or wells that are productive but do not produce enough to be commercially viable after drilling, operating and other costs. If the operators of our properties drill future wells that are identified as dry holes, the drilling success rate would decline and may adversely affect our results of operations.

Our derivatives activities could result in financial losses or could reduce our cash flow.

We enter into swaps, collars or other derivatives arrangements from time to time to hedge our expected production depending on projected production levels and expected market conditions. While intended to mitigate the effects of volatile oil and natural gas prices, such transactions may limit our potential gains and increase our potential losses if oil and natural gas prices were to rise substantially over the price established by the hedge.

Our actual future production may be significantly higher or lower than we estimate at the time we enter into derivative contracts for such period. If the actual amount of production is higher than we estimate, we will have greater commodity price exposure than we intended. If the actual amount of production is lower than the notional amount that is subject to our derivative financial instruments, we might be forced to satisfy all or a portion of our derivative transactions without the benefit of the cash flow from our sale of the underlying physical commodity, resulting in a substantial diminution of our liquidity. As a result of these factors, our hedging activities may not be as effective as we intend in reducing the volatility of our cash flows, and in certain circumstances may actually increase the volatility of our cash flows. In addition, such transactions may expose us to the risk of loss in certain circumstances, including instances in which:

- a counterparty to our derivative contracts is unable to satisfy its obligations under the contracts;
- our production is less than expected; or
- there is a widening of price differentials between delivery points for our production and the delivery point assumed in the derivative arrangement.

The present value of future net cash flows from our proved reserves is not necessarily the same as the current market value of our estimated proved reserves.

We base the estimated discounted future net cash flows from our proved reserves using a 12-month average price and costs in effect on the day of the estimate. However, actual future net cash flows from our oil and natural gas properties will be affected by factors such as:

- the volume, pricing and duration of our oil and natural gas hedging contracts;
- actual prices we receive for oil, natural gas and NGLs;
- our actual operating costs in producing oil, natural gas and NGLs;

- the amount and timing of our capital expenditures;
- the amount and timing of actual production; and
- changes in governmental regulations or taxation.

The timing of both our production and our incurrence of expenses in connection with the development and production of oil and natural gas properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net cash flows may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves, which could adversely affect our business, results of operations and financial condition.

Our business depends on oil and natural gas transportation and processing facilities and other assets that are owned by third parties.

The marketability of our oil and natural gas depends in part on the availability, proximity and capacity of pipeline systems, processing facilities, oil trucking fleets and rail transportation assets owned by third parties. The lack of available capacity on these systems and facilities, whether as a result of proration, physical damage, scheduled maintenance or other reasons, could result in the shut-in of producing wells or the delay or discontinuance of development plans for our properties. The curtailments arising from these and similar circumstances may last from a few days to several months. In many cases, operators are provided only with limited, if any, notice as to when these circumstances will arise and their duration. In addition, many of our wells are drilled in locations in the Williston Basin that are serviced only to a limited extent, if at all, by gathering and transportation pipelines, which may or may not have sufficient capacity to transport production from all of the wells in the area. As a result, we rely on third party oil trucking to transport a significant portion of our production to third party transportation pipelines, rail loading facilities and other market access points. Any significant curtailment in gathering system or pipeline capacity, or the unavailability of sufficient third party trucking or rail capacity, could adversely affect our business, results of operations and financial condition.

Certain of our undeveloped leasehold acreage is subject to leases that will expire over the next several years unless production is established or operations are commenced on units containing the acreage or the leases are extended.

We estimate that approximately half of our acreage is not currently held by production or held by operations. Unless production in paying quantities is established or operations are commenced on units containing these leases during their terms, the leases will expire. If our leases expire and we are unable to renew the leases, we will lose our right to develop the related properties. Drilling plans for these areas are generally in the discretion of third party operators and are subject to change based on various factors that are beyond our control, such as: the availability and cost of capital, equipment, services and personnel; seasonal conditions; regulatory and third party approvals; oil, NGL and natural gas prices; results of title work; gathering system and other transportation constraints; drilling costs and results; and production costs. As of December 31, 2011, we estimate that we had leases that were not developed that represented 17,677 net acres expiring in 2012, 23,765 net acres expiring in 2013 and 23,371 net acres expiring in 2014.

Seasonal weather conditions adversely affect operators' ability to conduct drilling activities in the areas where our properties are located.

Seasonal weather conditions can limit drilling and producing activities and other operations in our operating areas and as a result, a majority of the drilling on our properties is generally performed during the summer and fall months. These seasonal constraints can pose challenges for meeting well drilling objectives and increase competition for equipment, supplies and personnel during the summer and fall months, which could lead to shortages and increase costs or delay operations. Additionally, many municipalities impose weight restrictions on the paved roads that lead to jobsites due to the muddy conditions caused by spring thaws. This could limit access to jobsites and operators' ability to service wells in these areas.

Significant capital expenditures are required to replace our reserves.

Our exploration, development and acquisition activities require substantial capital expenditures. Historically, we have funded our capital expenditures through a combination of cash flow from operations, our credit facility and equity issuances. We have also engaged in asset sales from time to time. If our access to capital were limited due to numerous factors, which could include a decrease in operating cash flow due to lower oil and natural gas prices or decreased production or deterioration of the credit and capital markets, we would have a reduced ability to replace our reserves. We may not be able to incur additional bank debt, issue debt or equity, engage in asset sales or access other methods of financing on acceptable terms to meet our reserve replacement requirements.

The amount available for borrowing under our credit facility is subject to a borrowing base which is determined by our lenders, at their discretion, taking into account our estimated proved reserves and is subject to periodic redeterminations based on pricing models determined by the lenders at such time. The decline in oil and natural gas prices in 2008 adversely impacted the value of our estimated proved reserves and, in turn, the market values used by our lenders to determine our borrowing base. If commodity prices (particularly oil prices) decline, it will have similar adverse effects on our reserves and borrowing base and reduce our ability to replace our reserves.

We may be unable to obtain additional capital that we will require to implement our business plan, which could restrict our ability to grow.

Future acquisitions and future exploration, development, production and marketing activities, will require a substantial amount of capital. Cash reserves, cash from operations and borrowings under our revolving credit facility may not be sufficient to fund both our continuing operations and our planned growth. We may require additional capital to continue to grow our business through acquisitions and to further expand our exploration and development programs. We may be unable to obtain additional capital if and when required.

We may pursue sources of additional capital through various financing transactions or arrangements, including joint venturing of projects, debt financing, equity financing or other means. We may not be successful in consummating suitable financing transactions in the time period required or at all, and we may not be able to obtain the capital we require by other means. If the amount of capital we are able to raise from financing activities, together with our cash from operations, is not sufficient to satisfy our capital requirements, we may not be able to implement our business plan and may be required to scale back our operations, sell assets at unattractive prices or obtain financing on unattractive terms, any of which could adversely affect our business, results of operations and financial condition.

Our acquisition strategy will subject us to certain risks associated with the inherent uncertainty in evaluating properties for which we have limited information.

We have expanded our operations in part through acquisitions. Our decision to acquire a property will depend in part on the evaluation of data obtained from production reports and engineering studies, geophysical and geological analyses and seismic and other information, the results of which are often inconclusive and subject to various interpretations. Also, our reviews of acquired properties are inherently incomplete because it generally is not feasible to perform an in-depth review of the individual properties involved in each acquisition. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit us to become sufficiently familiar with the properties to assess fully their deficiencies and potential. Inspections may not always be performed on every well, and environmental problems, such as ground water contamination, are not necessarily observable even when an inspection is undertaken.

Any acquisition involves other potential risks, including, among other things:

- the validity of our assumptions about reserves, future production, revenues and costs;

- a decrease in our liquidity by using a significant portion of our cash from operations or borrowing capacity to finance acquisitions;

- a significant increase in our interest expense or financial leverage if we incur additional debt to finance acquisitions;

- the assumption of unknown liabilities, losses or costs for which we are not indemnified or for which our indemnity is inadequate;
- an inability to hire, train or retain qualified personnel to manage and operate our growing business and assets; and
- an increase in our costs or a decrease in our revenues associated with any potential royalty owner or landowner claims or disputes.

The loss of any member of our management team, upon whose knowledge, relationships with industry participants, leadership and technical expertise we rely could diminish our ability to conduct our operations, and harm our ability to execute our business plan.

Our success depends heavily upon the continued contributions of those members of our management team whose knowledge, relationships with industry participants, leadership and technical expertise would be difficult to replace. In particular, our ability to successfully acquire additional properties, to increase our reserves, to participate in drilling opportunities and to identify and enter into commercial arrangements depends on developing and maintaining close working relationships with industry participants. In addition, our ability to select and evaluate suitable properties and to consummate transactions in a highly competitive environment is dependent on our management team's knowledge and expertise in the industry. To continue to develop our business, we rely on our management team's knowledge and expertise in the industry and will use our management team's relationships with industry participants, specifically those of Mr. Reger our Chief Executive Officer, to enter into strategic relationships, which may take the form of joint ventures with other private parties and contractual arrangements with other oil and natural gas companies.

Although all of the members of our management team have entered into employment agreements with us, they may terminate their employment with our company at any time. If we were to lose members of our management team, we may not be able to replace the knowledge that they possess. In addition, we may not be able to establish or maintain strategic relationships with industry participants. If we were to lose the services of the members of our management team, our ability to conduct our operations and execute our business plan could be materially harmed.

Deficiencies of title to our leased interests could significantly affect our financial condition.

We typically do not incur the expense of a title examination prior to acquiring oil and natural gas leases or undivided interests in oil and natural gas leases or other developed rights. If an examination of the title history of a property reveals that an oil or natural gas lease or other developed rights have been purchased in error from a person who is not the owner of the mineral interest desired, our interest would substantially decline in value or be eliminated. In such cases, the amount paid for such oil or natural gas lease or leases or other developed rights may be lost. It is generally our practice not to incur the expense of retaining lawyers to examine the title to the mineral interest to be acquired. Rather, we typically rely upon the judgment of oil and natural gas lease brokers or landmen who perform the fieldwork in examining records in the appropriate governmental or county clerk's office before attempting to acquire a lease or other developed rights in a specific mineral interest.

Prior to drilling an oil or natural gas well, however, it is the normal practice in the oil and natural gas industry for the person or company acting as the operator of the well to obtain a preliminary title review of the spacing unit within which the proposed oil or natural gas well is to be drilled to ensure there are no obvious deficiencies in title to the well. Frequently, as a result of such examinations, certain curative work must be done to correct deficiencies in the marketability of the title, such as obtaining affidavits of heirship or causing an estate to be administered. Such curative work entails expense, and the operator may elect to proceed with a well despite defects to the title identified in the preliminary title opinion. Our failure to obtain perfect title to our leaseholds may adversely affect our current production and reserves and our ability in the future to increase production and reserves.

Competition in obtaining rights to explore and develop oil and natural gas reserves and to market our production may impair our business.

The oil and natural gas industry is highly competitive. Other oil and natural gas companies may seek to acquire oil and natural gas leases and other properties and services we will need to operate our business in the areas in which we expect to operate. This competition is increasingly intense as prices of oil and natural gas on the commodities markets have risen in recent years. Additionally, other companies engaged in our line of business may compete with us from time to time in obtaining capital from investors. Competitors include larger companies which, in particular, may have access to greater resources, may be more successful in the recruitment and retention of qualified employees and may conduct their own refining and petroleum marketing operations, which may give them a competitive advantage. In addition, actual or potential competitors may be strengthened through the acquisition of additional assets and interests. If we are unable to compete effectively or respond adequately to competitive pressures, our results of operation and financial condition may be materially adversely affected.

Our hedging activities expose us to potential regulatory risks.

The Federal Trade Commission (“FTC”), Federal Regulatory Commission (“FERC”) and the Commodities Futures Trading Commission (“CFTC”) have statutory authority to monitor certain segments of the physical and futures energy commodities markets. These agencies have imposed broad regulations prohibiting fraud and manipulation of such markets. With regard to hedging activities that we undertake with respect to oil, natural gas, NGLs, or other energy commodities, we are required to observe the market-related regulations enforced by these agencies. Failure to comply with such regulations, as interpreted and enforced, could have a material adverse effect on our business, results of operations and financial condition.

The adoption of derivatives legislation by the United States Congress could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

The United States Congress adopted comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. The new legislation was signed into law by the President on July 21, 2010 and requires the CFTC, the SEC and other regulators to promulgate rules and regulations implementing the new legislation. In December 2011, the CFTC extended temporary exemptive relief for certain regulations applicable to swaps, until no later than July 16, 2012. The CFTC has issued final regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain bona fide hedging transactions would be exempt from these position limits. It is not possible at this time to predict when the CFTC will make these regulations effective. The financial reform legislation may also require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our derivative activities, although the application of those provisions to us is uncertain at this time. The financial reform legislation may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty. The legislation and any new regulations could significantly increase the cost of derivative contracts (including from swap recordkeeping and reporting requirements and through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures or to make payments on our debt obligations. Finally, the legislation was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on our business, our financial condition, and our results of operations.

Our business is subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of doing business.

Our operational interests, as operated by our third-party operating partners, are regulated extensively at the federal, state and local levels. Environmental and other governmental laws and regulations have increased the costs to plan, design, drill, install, operate and abandon oil and natural gas wells. Under these laws and regulations, our company (either directly or indirectly through our operating partners) could also be liable for personal injuries, property and natural resource damage and other damages. Failure to comply with these laws and regulations may result in the suspension or termination of our business and subject us to administrative, civil and criminal penalties. Moreover, public interest in environmental protection has increased in recent years, and environmental organizations have opposed, with some success, certain drilling projects.

Part of the regulatory environment in which we do business includes, in some cases, legal requirements for obtaining environmental assessments, environmental impact studies and/or plans of development before commencing drilling and production activities. In addition, our activities are subject to the regulations regarding conservation practices and protection of correlative rights. These regulations affect our business and limit the quantity of natural gas we may produce and sell. A major risk inherent in the drilling plans in which we participate is the need for our operators to obtain drilling permits from state and local authorities. Delays in obtaining regulatory approvals or drilling permits, the failure to obtain a drilling permit for a well or the receipt of a permit with unreasonable conditions or costs could have a material adverse effect on the development of our properties. Additionally, the oil and natural gas regulatory environment could change in ways that might substantially increase the financial and managerial costs of compliance with these laws and regulations and, consequently, adversely affect our profitability. At this time, we cannot predict the effect of this increase on our results of operations. Furthermore, we may be put at a competitive disadvantage to larger companies in our industry that can spread these additional costs over a greater number of wells and larger operating staff.

Environmental risks may adversely affect our business.

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, state and municipal laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. There is risk of incurring significant environmental costs and liabilities as a result of the handling of petroleum hydrocarbons and wastes, air emissions and wastewater discharges related to our business, and historical operations and waste disposal practices. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, loss of our leases, incurrence of investigatory or remedial obligations and the imposition of injunctive relief.

Environmental legislation is evolving in a manner we expect may result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require us to incur costs to remedy such discharge, regardless of whether we were responsible for the release or contamination and regardless of whether our operating partners met previous standards in the industry at the time they were conducted. In addition, claims for damages to persons, property or natural resources may result from environmental and other impacts of operations on our properties. The application of environmental laws to our business may cause us to curtail production or increase the costs of our production, development or exploration activities.

Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

The U.S. Congress is considering legislation that would amend the federal Safe Drinking Water Act by repealing an exemption for the underground injection of hydraulic fracturing fluids near drinking water sources. Hydraulic fracturing is an important and commonly used process for the completion of oil and natural gas wells in shale formations, and involves the pressurized injection of water, sand and chemicals into rock formations to stimulate production. Sponsors of the legislation have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. If enacted, the legislation could result in additional regulatory burdens such as permitting, construction, financial assurance, monitoring, recordkeeping, and plugging and abandonment requirements. The legislation also proposes requiring the disclosure of chemical constituents used in the fracturing process to state or federal regulatory authorities, who would then make such information publicly available. The availability of this information could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, several state and local governments are considering or have adopted legislative or regulatory restrictions on hydraulic fracturing through additional permit requirements, operational restrictions, and temporary or permanent bans on hydraulic fracturing in certain environmentally sensitive areas such as watersheds. For example, Montana and North Dakota have both adopted regulations recently requiring the disclosure of all fluids, additives, and chemicals used in the hydraulic fracturing process. The adoption of any federal or state legislation or implementing regulations imposing reporting obligations on, or otherwise limiting, the hydraulic fracturing process could lead to operational delays or increased operating costs and could result in additional regulatory burdens that could make it more difficult to perform hydraulic fracturing and increase costs of compliance and doing business.

Climate change legislation or regulations restricting emissions of "greenhouse gases" could result in increased operating costs and reduced demand for the oil and natural gas that we produce.

In December 2009, the U.S. Environmental Protection Agency (the "EPA") determined that emissions of carbon dioxide, methane and other "greenhouse gases" ("GHG") present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. Based on its findings, the EPA has begun adopting and implementing regulations to restrict emissions of greenhouse gases under existing provisions of the Clean Air Act (the "CAA"). On September 22, 2009, the EPA issued a final rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the U.S. beginning in 2011 for emissions occurring in 2010. On November 30, 2010, the EPA published a final rule expanding its existing greenhouse gas emissions reporting rule to include certain petroleum and natural gas facilities, which rule requires data collection beginning in 2011 and reporting beginning in 2012. Our operating partners will be required to report certain of their greenhouse gas emissions under this rule by September 28, 2012. On May 12, 2010, the EPA also issued a "tailoring" rule, which makes certain large stationary sources and modification projects subject to permitting requirements for greenhouse gas emissions under the CAA. In addition, the EPA has continued to adopt GHG regulations of other industries, such as the March 2012 proposed GHG rule restricting future development of coal-fired power plants. As a result of this continued regulatory focus, future GHG regulations of the oil and gas industry remain a possibility. However, several of the EPA's greenhouse gas rules are being challenged in pending court proceedings and, depending on the outcome of such proceedings, such rules may be modified or rescinded or the EPA could develop new rules.

In addition, the U.S. Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases and almost one-half of the states have already taken legal measures to reduce emissions of greenhouse gases primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall greenhouse gas emission reduction goal. The adoption of legislation or regulatory programs to reduce emissions of greenhouse gases could require our third-party operating partners, and indirectly us, to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas produced by our operational interests. Consequently, legislation and regulatory programs to reduce emissions of greenhouse gases could have an adverse effect on our business, financial condition and results of operations.

Decommissioning costs are unknown and may be substantial. Unplanned costs could divert resources from other projects.

We may become responsible for costs associated with plugging, abandoning and reclaiming wells, pipelines and other facilities that we use for production of oil and natural gas reserves. Abandonment and reclamation of these facilities and the costs associated therewith is often referred to as "decommissioning." We accrue a liability for decommissioning costs associated with our wells, but have not established any cash reserve account for these potential costs in respect of any of our properties. If decommissioning is required before economic depletion of our properties or if our estimates of the costs of decommissioning exceed the value of the reserves remaining at any particular time to cover such decommissioning costs, we may have to draw on funds from other sources to satisfy such costs. The use of other funds to satisfy such decommissioning costs could impair our ability to focus capital investment in other areas of our business.

Our revolving credit agreement contains operating and financial restrictions that may restrict our business and financing activities.

Our revolving credit agreement contains, and any future indebtedness we incur may contain, a number of restrictive covenants that will impose significant operating and financial restrictions on us, including restrictions on our ability to, among other things:

- declare or pay any dividend or make any other distributions on, purchase or redeem our equity interests or purchase or redeem subordinated debt;
- make certain investments;
- incur or guarantee additional indebtedness or issue certain types of equity securities;
- create certain liens;
- sell assets;
- consolidate, merge or transfer all or substantially all of our assets; and
- engage in transactions with our affiliates.

As a result of these covenants, we will be limited in the manner in which we conduct our business, and we may be unable to engage in favorable business activities or finance future operations or capital needs.

Our ability to comply with some of the foregoing covenants and restrictions may be affected by events beyond our control. If market or other economic conditions deteriorate, our ability to comply with these covenants may be impaired. A failure to comply with the covenants, ratios or tests in our revolving credit agreement or any future indebtedness could result in an event of default under our revolving credit agreement or our future indebtedness, which, if not cured or waived, could have a material adverse effect on our business, financial condition and results of operations. If an event of default under our revolving credit agreement occurs and remains uncured, the lenders thereunder:

- would not be required to lend any additional amounts to us;
- could elect to declare all borrowings outstanding, together with accrued and unpaid interest and fees, to be due and payable;
- may have the ability to require us to apply all of our available cash to repay these borrowings; and
- may prevent us from making debt service payments under our other agreements.

An event of default or an acceleration under our revolving credit agreement could result in an event of default and an acceleration under other future indebtedness. Conversely, an event of default or an acceleration under any future indebtedness could result in an event of default and an acceleration under our revolving credit agreement. In addition, our obligations under the revolving credit agreement are collateralized by perfected first priority liens and security interests on substantially all of our assets and if we are unable to repay our indebtedness under the revolving credit agreement, the lenders could seek to foreclose on our assets.

Our leverage and debt service obligations may adversely affect our financial condition, results of operations and business prospects.

Our level of indebtedness could affect our operations in several ways, including the following:

- require us to dedicate a substantial portion of our cash flow from operations to service our existing debt, thereby reducing the cash available to finance our operations and other business activities and could limit our flexibility in planning for or reacting to changes in our business and the industry in which we operate;
- increase our vulnerability to economic downturns and adverse developments in our business;
- limit our ability to access the capital markets to raise capital on favorable terms or to obtain additional financing for working capital, capital expenditures or acquisitions or to refinance existing indebtedness;
- place restrictions on our ability to obtain additional financing, make investments, lease equipment, sell assets and engage in business combinations;
- place us at a competitive disadvantage relative to competitors with lower levels of indebtedness in relation to their overall size or less restrictive terms governing their indebtedness; and
- make it more difficult for us to satisfy our obligations under our debt agreements and increase the risk that we may default on our debt obligations.

Our ability to meet our expenses and debt obligations will depend on our future performance, which will be affected by financial, business, economic, regulatory and other factors. We will not be able to control many of these factors, such as economic conditions and governmental regulation. We depend on our revolving credit facility for future capital needs, because we use operating cash flows for investing activities and borrow as needed. We cannot be certain that our cash flow will be sufficient to allow us to pay the principal and interest on our current and future debt and meet our other obligations. If we do not have enough money, we may be required to refinance all or part of our debt, sell assets, borrow more money or raise equity. We may not be able to refinance our debt, sell assets, borrow more money or raise equity on terms acceptable to us, if at all. Our ability to comply with the financial and other restrictive covenants in our indebtedness will be affected by the levels of cash flow from our operations and future events and circumstances beyond our control. Failure to comply with these covenants would result in an event of default under our indebtedness, and such an event of default could adversely affect our business, financial condition and results of operations.

Availability under our revolving credit facility is determined semi-annually, as well as upon the occurrence of certain events, by the lenders in their sole discretion, based primarily on reserve reports that reflect our banks' projections of future commodity prices at such time. Significant declines in natural gas, NGL or oil prices may result in a decrease in our borrowing base. The lenders can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under the revolving credit facility. Any increase in the borrowing base requires the consent of all the lenders. If as a result of a borrowing base redetermination outstanding borrowings are in excess of the borrowing base, we must repay such excess borrowings immediately or in equal installments over six months, or we must pledge other properties as additional collateral. We do not currently have any substantial unpledged properties, and we may not have the financial resources in the future to make any mandatory principal prepayments required under the revolving credit facility.

We may not be able to generate enough cash flow to meet our debt obligations.

We expect our earnings and cash flow to vary significantly from year to year due to the cyclical nature of our industry. As a result, the amount of debt that we can service in some periods may not be appropriate for us in other periods. Additionally, our future cash flow may be insufficient to meet our debt obligations and commitments. Any insufficiency could negatively impact our business. A range of economic, competitive, business and industry factors will affect our future financial performance, and, as a result, our ability to generate cash flow from operations and to pay our debt. Many of these factors, such as oil and natural gas prices, economic and financial conditions in our industry and the global economy or competitive initiatives of our competitors, are beyond our control.

If we do not generate enough cash flow from operations to satisfy our debt obligations, we may have to undertake alternative financing plans, such as:

- refinancing or restructuring our debt;
- selling assets;
- reducing or delaying capital investments; or
- seeking to raise additional capital.

However, we cannot assure you that undertaking alternative financing plans, if necessary, would allow us to meet our debt obligations. Our inability to generate sufficient cash flow to satisfy our debt obligations, or to obtain alternative financing, could materially and adversely affect our business, financial condition, results of operations and prospects.

Our variable rate indebtedness subjects us to interest rate risk, which could cause our debt service obligations to increase significantly.

Borrowings under our revolving credit facility bear interest at variable rates and expose us to interest rate risk. If interest rates increase and we are unable to effectively hedge our interest rate risk, our debt service obligations on the variable rate indebtedness would increase even if the amount borrowed remained the same, and our net income and cash available for servicing our indebtedness would decrease. A 1% increase in interest rates on the debt outstanding under our revolving credit facility as of March 31, 2012 would cost us approximately $1.8 million in additional annual interest expense.

Despite our current level of indebtedness, we may still be able to incur substantially more debt. This could further exacerbate the risks associated with our substantial indebtedness.

We may be able to incur substantial additional indebtedness in the future, subject to certain limitations, including under our revolving credit facility and under any future debt agreements. If new debt is added to our current debt levels, the related risks that we now face could increase. Our level of indebtedness could, for instance, prevent us from engaging in transactions that might otherwise be beneficial to us or from making desirable capital expenditures. This could put us at a competitive disadvantage relative to other less leveraged competitors that have more cash flow to devote to their operations. In addition, the incurrence of additional indebtedness could make it more difficult to satisfy our existing financial obligations.

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

Recent Sales of Unregistered Securities

None.

Issuer Purchases of Equity Securities

The table below sets forth the information with respect to purchases made by or on behalf of the company, or any “affiliated purchaser” (as defined in Rule 10b-18(a)(3) under the Securities Exchange Act of 1934), of our common stock during the quarter ended March 31, 2012.

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Period	Total Number of Shares Purchased(1)	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publically Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet be Purchased Under the Plans or Programs(2)
Month #1				
January 1, 2012 to January 31, 2012	47,140	$ 24.89	-	150 million
Month #2				
February 1, 2012 to February 29, 2012	-	-	-	150 million
Month #3				
March 1, 2012 to March 31, 2012	-	-	-	150 million
Total	47,140	$ 24.89	-	150 million

(1) All shares purchased reflect shares surrendered by company employees in satisfaction of tax obligations in connection with restricted stock awards.

(2) 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. We have not made any repurchases under this program to date.

Item 5. Other Information

On January 1, 2012, we adopted 2011-05, Comprehensive Income (Topic 220): Presentation of Comprehensive Income (ASU 2011-05) which requires presentation of the components of net income and other comprehensive income either as one continuous statement or as two consecutive statements and eliminates the option to present components of other comprehensive income as part of the statement of changes in stockolders' equity. The following presents the retrospective application of ASU 2011-05 for each of the three years ended December 31, 2011, 2010 and 2009:

Northern Oil and Gas, Inc.
Consolidated Statements of Comprehensive Income

	Year ended December 31,		
	2011	2010	2009
Net Income	$40,611,492	$6,917,300	$2,798,952
Unrealized gains (losses) on Marketable Securities (net of tax of $109,000, $349,000 and $290,000 at December 31, 2011, 2010 and 2009)	173,846	553,135	(486,207)
Reclassification of derivative instruments included in income (net of tax of $448,000, $446,000 and $933,000 at December 31, 2011, 2010 and 2009)	709,776	711,554	(1,483,639)
Comprehensive Income	$41,495,114	$8,181,989	$829,106

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:	May 7, 2012	By:	/s/ Michael L. Reger Michael L. Reger, Chief Executive Officer and Director
Date:	May 7, 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
10.1	Third Amended and Restated Credit Agreement, dated as of February 28, 2012, among Northern Oil and Gas, Inc., as Borrower, Royal Bank of Canada, as Administrative Agent, SunTrust Bank, as Syndication Agent, Bank of Montreal, KeyBank, N.A. and U.S. Bank N.A., as Co-Documentation Agents, 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 March 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	XBRL Taxonomy Extension Presentation Linkbase Document(1)	Filed herewith

(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.