UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Form 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2011

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission file number: 001-32977

GMX RESOURCES INC.

(Exact name of registrant as specified in its charter)

Oklahoma	**73-1534474**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
9400 North Broadway, Suite 600, Oklahoma City, Oklahoma	**73114**
(Address of principal executive offices)	**(Zip Code)**

(405) 600-0711

(Registrant's telephone number, including area code)

Securities registered under Section 12(b) of the Exchange Act:

Title of Class	Name of Exchange on Which Registered
Common Stock, $0.001 par value	New York Stock Exchange
Series B Cumulative Preferred Stock, $0.001 par value	New York Stock Exchange
Series A Preferred Stock Purchase Rights	New York Stock Exchange

Securities registered under Section 12(g) of the Exchange Act: None

Indicate by check mark if registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☒

Indicate by check mark if registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

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 ☒ 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 ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

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 definition of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. Check one:

Large accelerated filer ☐	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 Act) Yes ☐ No ☒

As of June 30, 2011, the aggregate market value of the registrant's common stock held by non-affiliates was $255,200,625 based on the closing price of such common stock in the daily composite list of transactions on the New York Stock Exchange of $4.45.

As of March 8, 2012, there were 64,332,007 shares of the registrant's common stock outstanding, including 2,364,375 shares under a share lending agreement that will be returned to the registrant upon conversion or maturity of certain outstanding convertible notes and 1,246,575 shares of unvested restricted stock.

DOCUMENTS INCORPORATED BY REFERENCE: Portions of the registrant's definitive proxy statement for its 2012 Annual Meeting of Shareholders (to be filed within 120 days of the close of the registrant's fiscal year) are incorporated by reference into Part III of this Form 10-K.

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PART I

Item 1. Business.

General

GMX Resources Inc. and its subsidiaries (collectively, "GMX" the "Company", "we," "us" and "our") is an independent oil and natural gas exploration and production company with a portfolio of leasehold acreage in multiple resource plays that allow us flexibility to deploy capital based on a variety of economic and technical factors, including commodity prices (including differentials applicable to the basin) well costs, service availability, and take-away capacity.

Prior to 2011, the Company focused on the development of the hydrocarbon formations in East Texas including the Cotton Valley Sands ("CVS") layer in the Schuler formation and the Upper, Middle and Haynesville/Lower Bossier layers of the Bossier formation (the "Haynesville/Bossier Shale", or "H/B"), in the Sabine Uplift of the Carthage, North Field primarily located in Harrison and Panola counties of East Texas (previously designated as our "primary development area").

In late 2010, we made a strategic decision to expand our asset base and development activities into other basins in order to diversify our significant concentration in natural gas to a multiple basin and commodity strategy with more liquid hydrocarbon opportunities. In the first half of 2011, we acquired core positions in over 75,000 undeveloped net acres in two of the leading oil resource plays in the U.S.; the Williston Basin of North Dakota/Montana, targeting the Bakken/ Three Forks Formation, and in the oil window of the Denver Julesburg Basin (the "DJ Basin") of Wyoming, targeting the emerging Niobrara Formation. We believe the flexibility with the acquisition of the liquids-rich (estimated 90% oil) Bakken and Niobrara acreage will enable us to generate higher cash flow growth to fund our capital expenditure program. The Company is leveraging our expertise in H/B Shale horizontal drilling to successfully develop these newly acquired oil resource plays. A summary of the 2011 transactions are as follows:

- *Bakken acquisitions*-During the first half of 2011, we acquired all of the working interest and an average greater than 80% net revenue interest in approximately 35,000 undeveloped net acres of oil and gas leases located in Billings, Stark, McKenzie and Dunn Counties of North Dakota, and Richland, Sheridan and Wibaux Counties of Montana. We hold Williston Basin leases in approximately 150 1,280-acre units and expect to be the operator in approximately 31 of those units, providing a minimum of 172 operated locations.

- *Niobrara acquisitions*-During the first half of 2011, we acquired all of the working interest and an 80% net revenue interest in approximately 40,000 undeveloped net acres of oil and gas leases located in Platte, Goshen and Laramie Counties of Wyoming. We hold DJ Basin leases in approximately 146 640-acre units and expect to be the operator in approximately 95 of those units, providing a minimum of 380 operated locations.

During 2011, we initiated our transition to a balanced mix of natural gas and liquids revenue by acquiring a significant position in the Bakken and Niobrara petroleum systems and focusing our resources on drilling and completing this new liquids-rich undeveloped acreage. This transition was evidenced for the year ended December 31, 2011 by our cash outlays for capital expenditures of $272 million, of which $126 million was the cash portion of acreage acquisitions and seismic in the Williston Basin, DJ Basin-Niobrara and East Texas, $124 million was for drilling operations, and $22 million related to capitalized interest, and other corporate expenditures. Of the $124 million in capital expenditures for drilling operations, $16.2 million related to drilling operations in the Williston Basin-Niobrara and $107.8 million related to East Texas drilling and other capital expenditures. Of our total cash capital expenditures for 2011, $119.4 million, or 44%, was directly related to lease and seismic acquisitions and development of our Bakken and Niobrara assets. As a result, total oil production increased 16% in the fourth quarter 2011 to 28,171 barrels compared to 24,235 barrels in fourth quarter 2010. We expect to make capital expenditures of approximately $97 million in 2012 (including capitalized interest and general and administrative ("G&A")), of which we plan $68 million will be direct Bakken drilling and completion costs, or 70% of our total estimated 2102 capital expenditures, resulting in approximately 7.1 new net Bakken wells. We project oil production will increase approximately 300% from 92,837 barrels during 2011 to approximately 373,000 barrels during 2012.

Including VPP volumes, daily production for 2011 averaged 65.7 Mcfe, an increase of 17.8 million cubic feet of natural gas equivalent (MMcfe). Our estimated total proved reserves as of December 31, 2011 were 285.3 billion cubic feet of natural gas equivalent (Bcfe), which includes a reduction in reserves to reflect the volumetric production payment transaction,"VPP", that closed in December 2011, which reduced our reserves by 14.7 Bcfe. Our reserves at December 31, 2011 were 96.4% gas and 57% proved developed. (See the Oil and Natural Gas Reserves section below for additional information.)

We have three subsidiaries: Diamond Blue Drilling Co. ("Diamond Blue"), which previously owned three drilling rigs, Endeavor Pipeline Inc. ("Endeavor Pipeline"), which operates our water supply and salt water disposal systems in our East Texas area, and Endeavor Gathering, LLC ("Endeavor Gathering"), which owns the natural gas gathering system and related equipment operated by Endeavor Pipeline. Kinder Morgan Endeavor LLC ("KME") owns 40% membership interest in Endeavor Gathering.

Information about Us

Our principal executive office is located at 9400 North Broadway, Suite 600, Oklahoma City, Oklahoma, 73114 and our main telephone number at that location is (405) 600-0711. On our website www.gmxresources.com we provide, at no cost, our annual reports on Form 10-K, quarterly reports on From 10-Q, current reports on Form 8-K, and amendments to those reports as soon as reasonably practicable after we electronically file such material with, or furnish it to, the Securities and Exchange Commission. From time to time, we also post announcements, updates, events, investor information and presentations on our website in addition to copies of all recent press releases.

Summary of Significant 2011 Events and Recent Developments

Acquisition of Williston Basin (Bakken) Acreage

During 2011, we acquired approximately 35,000 net acres in the Bakken/Three Forks oil resource play, which provides us with over 400 potential horizontal locations. We intend to continue our multi-year drilling program in 2012, expanding to a multi-rig program based on available liquidity and capital resources. We estimate our Bakken locations provide us with approximately 17 years of drilling inventory for three rigs. We may selectively acquire additional acreage in these project areas in the normal course of business.

Senior Notes Offerings and Equity Issuance

On February 9, 2011, we issued $200 million in aggregate principal amount of 11.375% senior notes due 2019 in a private placement. Concurrently with this notes offering in February 2011, we also sold 21,075,000 shares of our common stock in a public offering for net proceeds after underwriters' fees but before expenses of $93.6 million, and an additional 1,098,518 shares of common stock in connection with the underwriters' exercise of an option to purchase additional shares for additional net proceeds of $4.9 million after underwriter fees. We used the net proceeds of these offerings (i) to fund the purchase of undeveloped oil and gas leases in the Williston Basin (Bakken/Three Forks Formation) and Denver Julesburg Basin (Niobrara Formation), (ii) to repay the current outstanding balance under our secured revolving credit facility, (iii) to fund an offer to purchase up to $50.0 million of our outstanding 5.00% convertible senior notes due 2013, (iv) to fund our exploration and development program and (v) for other general corporate purposes.

Suspension of Haynesville/Bossier Development

Based on market conditions for natural gas and the cost to develop this acreage remaining at higher than economically viable levels, we decided in mid-2011 to temporarily suspend continued development of our East Texas H/B acreage and to focus our capital and resources on our newly acquired Bakken and Niobrara oil-focused acreage. Our last H/B well was drilled, completed and brought on line in August 2011.

Reduced Rig Lease Contract Obligations

We have subleased all four of our Helmerich and Payne ("H&P") FlexRig. Three rigs, which resulted in savings of $24 million in our future lease obligations. The H&P Flex Rigs lease terms end with two rigs in March and October of 2012, and with the final two Flex Rigs in January and March of 2013.

VPP Financing Agreement

During December 2011, we sold a term overriding royalty interest, or VPP, in certain long-lived producing assets in the Haynesville Bossier ("H/B") layer in Harrison County in East Texas to EDF Trading North America, LLC. The VPP is for approximately 14.7 Bcf to be produced over the next ninety-five months commencing December 1, 2011. GMXR will retain all of its oil and NGL production associated its assets. The $49.7 million transaction, based on the natural gas futures prices, closed on December 9, 2011, and was effective December 1, 2011. The VPP will be treated as a sale for accounting purposes and our oil and natural gas properties have been reduced accordingly. The reduction of approximately $46 million from the VPP is included in our year-end 2011 PV-10 of $186.6 million. Production of natural gas from these properties sold through the VPP for 2012 will be approximately 4.0 Bcf.

Termination of Credit Agreement and Elimination of Financial Covenants

We terminated our bank revolving credit agreement during December 2011 and are no longer subject to the financial maintenance covenants and restrictions contained in that agreement. We do not have any financial maintenance covenants under the indentures governing our current long-term debt obligations.

Settlement of Natural Gas Hedges

We monetized our natural gas hedges in December 2011, which provided to us approximately $18.5 million in net cash proceeds excluding fees and commissions.

Note Exchange, Senior Secured Notes Issuances and Related Equity Issuance

On December 19, 2011, we accepted tenders and consents from the holders of $198 million aggregate principal amount of its outstanding $200 million 11.375% Senior Notes due 2019, which were originally issued on February 9, 2011 (the "11.375% Senior Notes"), in connection with a private exchange offer and consent solicitation for the 11.375% Senior Notes. Holders of the 11.375% Senior Notes tendering in the exchange offer received Senior Secured Notes due 2017 (the "Senior Secured Notes").

Pursuant to the terms of the exchange offer, holders of the 11.375% Senior Notes were entitled to exchange, for each $1,000 principal amount of 11.375% Senior Notes tendered by such holder, either: (a) $750.00 principal amount of Senior Secured Notes (the "Exchange Only Election") or (b) $971.40 principal amount of Senior Secured Notes, if the holder subscribed to purchase for cash an additional $600.00 principal amount of Senior Secured Notes, to be issued at par, in a private placement being made to the holders in connection with the Exchange Offer for each $1,000 principal amount of 11.375% Senior Notes tendered by such holder (the "Exchange and Purchase Election").

Holders tendering pursuant to the Exchange and Purchase Election tendered $144.6 million in aggregate principal amount of 11.375% Senior Notes. Holders tendering pursuant to the Exchange Only Election tendered $53.5 million in aggregate principal amount of 11.375% Senior Notes.

On November 2, 2011, prior to the consummation of the exchange offer, we entered into separate support agreements (the "Support Agreements") with holders collectively of greater than 50% ("Supporting Holders") of the 11.375% Senior Notes. Pursuant to the Support Agreements, the Supporting Holders agreed to purchase their pro rata amount of Senior Secured Notes offered in the exchange offer and, if tendering holders did not elect to purchase at least $100.0 million aggregate principal amount of Senior Secured Notes in connection with the exchange offer, to purchase for cash their pro rata amount of additional Senior Secured Notes such that the aggregate principal amount of Senior Secured Notes issued would be $100.0 million (the "Backstop Obligations"). As consideration for the Backstop Obligations, the Supporting Holders collectively received approximately 3.88 million shares of our common stock (calculated as a $7 million value based on a specified weighted average price) and $3.0 million aggregate principal amount of Senior Secured Notes.

Including the Senior Secured Notes issued as consideration for the Backstop Obligations, we issued Senior Secured Notes in an aggregate principal amount of $283.5 million. We received gross cash proceeds of $100.0 million in connection with the issuance of the Senior Secured Notes, including approximately $13.3 million of cash from the Supporting Holders pursuant to their Backstop Obligations.

In connection with the exchange offer and related consent solicitation for the 11.375% Senior Notes, we entered into a supplemental indenture to the indenture governing the 11.375% Senior Notes to, among other things; eliminate substantially all of the restrictive covenants and certain event of default provisions in the indenture governing the 11.375% Senior Notes. An aggregate of $1,970,000 principal amount of 11.375% Senior Notes that was not tendered and purchased pursuant to the tender offer remains outstanding, and the holders thereof are subject to the terms of the supplemental indenture.

The Senior Secured Notes mature in December 2017. The Senior Secured Notes accrue cash interest at 11.0% per annum (or, at our option, 9.0% cash pay and 4.0% payment in kind in additional Senior Secured Notes). The Senior Secured Notes are secured by first-priority perfected liens on substantially all right, title and interest in or to substantially all of the assets and properties owned or acquired by the Company and the guarantors.

Reduction in General and Administrative Expenses

We have undertaken a comprehensive review of our general and administrative expenses and implemented a number of reductions during the fourth quarter of 2011 and first quarter of 2012. Total cash expenditures for G&A expenses in 2011 were $37.7 million, before deductions of capitalized cash G&A expenses of $8.8 million. For 2012, total cash expenditures for G&A expenses are projected to be $26 million including $5 million of capitalized cash G&A expenses. The $11.7 million reduction in cash expenditures for G&A expenses is projected as result of the following:

- Reductions in cash compensation, long-term incentive payments and annual incentive bonuses for executive officers.

- A reduction in force of approximately 13% of the employee base through attrition and consolidation of responsibilities.
- The reduction or elimination of a number of other non-compensation related G&A expenses.

Total 2011 cash compensation paid or awarded to the top three executive officers was approximately 36% less than they received in 2010. In addition, approximately 25% of the cash compensation for the top three executive officers based on 2011 performance may be deferred by the Company for two years and may be paid in common shares, if available, under the Company's Long-Term Incentive Plan.

Bakken Development Activity

During 2011 and the first two months of 2012, we successfully drilled and completed five Bakken Petroleum System wells, all in North Dakota. The Wock 21-2-1H, Frank 31-4-1H and the Marsh 21-16 TFH wells are located in Stark County, while the Taboo 1-25-36H and the Evoniuk 21-2-1H are located in McKenzie and Billings County, North Dakota. We successfully drilled our fourth operated well, the Lange 11-30-1H, in McKenzie County, North Dakota. The Lange 11-30-1H will be completed as a Middle Bakken well and we anticipate that we will commence fracture stimulating of this well in March 2012.

The Pojorlie #21-2-1H well in McKenzie County, North Dakota, is scheduled to spud in early March 2012. The Pojorlie 21-2-1H will be drilled as test of the Three Forks formation. We plan to core this well from the Middle Bakken into the Three Forks. We have a 34% working interest in the well.

Our fifth operated well spud on February 28, 2012. The Akovenko 24-34-1H is located in McKenzie County, North Dakota, and we plan to drill this well as a Middle Bakken test. We project a 74% working interest in the well.

During February 2012, we elected to participate with Continental Resources in the drilling of the GCR 1-25H well located in Billings County, North Dakota. The well is a planned Three Forks test. We have a 9.4% working interest in the well.

We have signed a one-year contract for a new-build, dedicated fit-for-purpose workover rig and crew, with expected arrival to be the first week in March 2012. We currently plan to focus our drilling operations in McKenzie and Billings Counties, where we expect to operate 31 units representing a possible 172 locations within these two counties.

Strategy

Our current strategy is to focus virtually all our 2012 development capital in the Bakken oil resource play, which we believe will provide the Company current maximum economic return and creation of enterprise value. We have currently contracted one rig to drill our Bakken wells in 2012. Our strategies emphasize:

- *Developing our undeveloped acreage in the Bakken Formation*-During 2011, we acquired approximately 35,000 net acres in the Bakken/Three Forks oil resource play which provides us with more than 400 possible undeveloped horizontal locations. We intend to continue our single rig drilling program in 2012 expanding to a multi-rig, multi-year program based on available liquidity and capital resources. We estimate our Bakken locations provide us with approximately 17 rig years of drilling inventory with three rigs. We may selectively acquire additional acreage in these project areas in the normal course of business.
- *Increasing higher margin crude oil production*-We plan to increase our operating cash flows and profitability by deploying our working capital to increase oil production and reserves in our Bakken and Niobrara acreage. As crude oil and natural gas prices fluctuate, we will continue to evaluate our allocation of capital between our oil and natural gas resources.
- *Using our Haynesville/Bossier horizontal drilling and on-staff technical experience to economically develop our newly acquired Bakken and Niobrara acreage*-Our team has drilled and completed 38 Haynesville/Bossier producing horizontal wells, and we significantly reduced our completed well cost to under $1,367 per lateral foot in 2011 compared to $1,700 per lateral foot in the fourth quarter of 2010. We realized excellent spud to total depth drilling times from an average of 29 days to drill a horizontal well with an average lateral length of 6,243 feet in 2010 to an average of 31 days to drill longer horizontal wells with an average lateral length of 6,593 in 2011. We have assembled a technical staff with PhDs in Engineering and Geology and with Rocky Mountain experience, including the following basins: Powder River Basin, Williston Basin, Uinta Basin, San Juan Basin, Piceance Basin, D-J Basin, Wind River Basin, Greater Green River Basin, Shirley-Hannah Basin and Canadian Rockies. We have also assembled an experienced group of senior land executives with wide-ranging experiences in acquisition, integration, and operation in conventional and unconventional resource plays in more than one million acres, covering multiple-rig drilling programs over the past 25 years in the Anadarko (Woodford and

Granite Wash), Arkoma (Fayetteville, Woodford Caney and CBM), Permian, Hugoton, Barnett Shale, Haynesville / Bossier Shale, Bakken and Three Forks, and Marcellus Shale basins. In the Bakken, our first three wells hit total depth in 2011, and had an average spud to total depth time of 42 days.

- *Maintaining operational control with focus on reducing operating costs*-We have consistently maintained low finding and development costs and consistently operate with one of the lower operating cost structures in the industry. Our per unit lease operating expenses declined from $0.61 per Mcfe for the year ended December 31, 2010 to $0.56 per Mcfe for the year ended December 31, 2011. The costs to operate oil wells are higher than gas wells due to the costs associated with pumps and other liquids handling facilities. We are forecasting $8,000 per month of fixed cost per gross well, plus $3.34/BBL for variable costs. As we drill and participate in more oil wells, this cost structure will increase our average per unit operating cost.

- *Actively hedging production to provide greater certainty of cash flow and earnings*-Through December 2011, we had an active natural gas hedge position. We hedged approximately 14.8 million MMBtu of natural gas at a weighted average floor price of $6.13 for the year ended December 31, 2011 representing 63% of our average daily production. In December 2011, we monetized our hedge position, resulting in net cash to us of $18.5 million. We expect to recommence hedging in 2012, will continue to evaluate pricing and will hedge future production as economic conditions warrant.

- *Providing economic flexibility with three high quality basins*-As a result of our 2011 acquisitions, we have over 35,000 net acres in the Bakken and more than 40,000 net acres in the Niobrara. We have approximately 53,000 gross acres (35,000 net acres) containing our Haynesville/Bossier Shale resource development in Harrison and Panola counties Texas and Caddo parish, Louisiana. As of December 31, 2011, we have drilled and completed 38 gross (37.1 net) successful horizontal H/B wells. We have identified 253 net potential undrilled H/B locations across our core area property base, based on 80-acre spacing. Furthermore, we drilled 19 vertical test wells in 2006, which confirmed a consistent 350-foot layer of Haynesville/Bossier Shale to be present and substantially reduced the risk associated with our H/B acreage. The CVS resource development contains about 55,000 gross acres (36,000 net acres) and has 302 producing locations, and 83 net potential undrilled 80-acre horizontal locations in our East Texas core area. We have a successful track record of drilling in our East Texas core area. A significant portion of our Haynesville/Bossier Shale and Cotton Valley Sands acreage is held by production, which gives us the ability to drill where and when we choose without significant risk of lease expirations.

Oil and Gas Properties as of December 31, 2011

The following section summarizes our oil and gas properties as of December 31, 2011.

Williston Basin - Bakken

Our entry into the Williston Basin involves transactions for approximately 35,000 total net acres in seven counties. The acreage is located primarily in five distinct areas, all of which are within the Bakken "thermal maturity window." The leases have an average of more than 80% NRI and are a mix of fee (freehold), state and federal leases, all taken during 2010 or 2011. The leases generally have five-year primary terms, and many of the fee leases have options to renew for five more years. The total acreage represents the potential for 31 operated units representing a possible 172 locations.

The Upper Devonian and Lower Mississippian Bakken Formation is an unconventional reservoir that produces oil, predominantly, from natural fracture systems. The Bakken Formation consists of three informal but distinct members that were deposited in an intra-cratonic basin: an organic-rich upper black shale that is up to 25 feet thick; an organic-poor middle grey-brown calcareous siltstone, sandstone or dolomitic limestone that is up to 85 feet thick; and a lower organic-rich black shale similar to the upper member that is up to 50 feet thick. The upper and lower shale members contain significant volumes of type II oil-prone kerogen. Total organic carbon of the upper and lower members averages around 12% by weight and is well within the oil generation window. The Bakken Total Petroleum System is often described in conjunction with a "false Bakken" hot shale located in the overlying Lodgepole formation, and the Three Forks calcareous, siltstone/sandstone located right below the Bakken.

We are currently budgeting 2012 capital expenditures in the Williston Basin to be $68 million for 7.1 net wells and to continue drilling 10,000' laterals in our Bakken play. We have successfully recruited experienced Bakken land staff, brokerage and title teams to augment our current land staff capacities and competencies. We plan to create data sharing relationships with other operators in the basin. We have hired several employees and use local consultants in the area to execute our initial plans. As we expand our development, we intend to establish a GMXR field office in the area.

We intend to focus our 2012 drilling and development activity on our McKenzie County and Billings County, North

Dakota leaseholds. We believe that a significant portion of our Billings and McKenzie Counties acreage position has been de-risked by us and several other operators. Our fourth operated Bakken well and second McKenzie County well, the Lange #11-30-1H is scheduled for completion in March 2012. With a target of Middle Bakken production, the Lange #11-30-1H is a direct offset and located 3,000 feet east of the Taboo #1-25-36+H. We have elected to participate with Continental Resources Inc. in the drilling of the Pojorlie #21-2-1H well and we have a 34% working interest in the well which is expected to spud in early March 2012. In Stark County North Dakota, we have drilled and completed two Three Forks wells. The Wock #21-2-1H and Frank #31-4-1H were both successfully fracture stimulated and a workover rig is planned, beginning in March 2012, to clean out their laterals. These wells represent four successfully drilled and completed wells in our Bakken Petroleum System acreage and drilling program.

We have continued to make significant progress in completing the necessary steps to receive permits on both our Federal and State leaseholds. As of February 23, 2012, we have (i) two additional locations permitted and two in process in McKenzie County, (ii) one permitted and five in process in Billings County and (iii) two additional locations permitted in Stark County, North Dakota. In addition to the four wells that we have already elected to participate in, we have an additional seven wells that we expect to participate in during 2012 with working interests ranging between 1% and 14%, with an average of 5%.

In January 2012, we entered into a one-year contract for a workover rig to remove restrictive materials from the 10,000-foot laterals in the first three operated wells and available for future work as required. As experienced by other operators in the Williston Basin, workover rigs have become another operational bottleneck as the need to clean out newly completed wells from a higher rig count, as well as routine maintenance for a growing number of producing wells, stress current service capabilities.

East Texas

As of December 31, 2011, we owned 386 gross (250.2 net) producing wells. In our East Texas core area, 302 gross (174 net) wells were Cotton Valley Sands wells at depths of 8,000 to 12,000 feet, 41 gross (35 net) wells were productive in the shallower conventional Rodessa, Travis Peak, Hosston and Pettit formations in our core area, and 38 gross (37.6 net) Haynesville/Bossier Shale horizontal wells were producing, with 5 gross (2.8 net) wells in Louisiana at year-end 2011. We have historically grown by developing in our core area with a high degree of drilling success and with low finding and development costs. "Finding and Development Costs" is defined in "Glossary of Oil and Gas Terms." The Cotton Valley Sands and Haynesville/Bossier are considered to be unconventional natural gas resources that are pervasive throughout large areas, which explains our historical drilling success in these formations.

As of December 31, 2011, we had approximately 253 net proved and unproved Haynesville/Bossier Shale drilling locations (based on 80 acre well spacing) in Harrison and Panola Counties, Texas surrounded by our existing wells and other operators drilling Haynesville/Bossier Shale wells. Our H/B acreage as of December 31, 2011 was approximately 53,000 gross and 35,000 net acres.

As of December 31, 2011, we had approximately 55,000 gross and 36,000 net acres in the Cotton Valley Sands formation, with 83 undrilled Cotton Valley Sands horizontal drilling locations in our core East Texas area based on 80-acre spacing.

Our East Texas area properties accounted for more than 98% of our total proved reserves at December 31, 2011, 48% of our total net acreage and 99% of our 2011 production.

We operate 182, or 47%, of our East Texas area gross wells, which operated wells produced 91% of our oil and natural gas production as of December 31, 2011. Average daily net operated plus non-operated production in 2011 was 57.3 MMcf of gas and 1,150.8 Bbls of oil and natural gas liquids. The producing lives of these fields are generally between 12 to 70 years, with a majority of the gas produced in the first ten years. Cotton Valley Sands gas sold from the area has a high MMBtu content, which after processing, can result in a net price above average daily Henry Hub natural gas prices. Oil is sold separately at a slight discount to the average Sweet Crude oil price at Cushing, Oklahoma (the NYMEX delivery point), inclusive of deductions. The acreage in East Texas lies on the Sabine Uplift, a broad positive feature that acts as a structural trap for most reservoirs. Most of the reservoirs contain shallow and deep marine sediments that tend to have tremendous aerial extent and substantial thicknesses. Natural gas and oil have been produced from 3,000 feet to 11,700 feet in our core area. Prior to shifting our focus to the Haynesville/Bossier Shale, the primary objective of our development was the Cotton Valley Sands, which occurs between 8,200 feet and 10,000 feet and contains multiple layers of sands containing natural gas. Due to the multiple layers and widespread deposition of these gas saturated layers, we have a very high success rate of finding commercial wells.

At December 31, 2010 in accordance with the SEC five-year limitation on proved undeveloped locations, we removed approximately 290 net proved undeveloped locations related to the Cotton Valley Sands from our 2010 reserve report due to our focus on the new oil resource plays, as well as the intention to develop the Cotton Valley Sands on a horizontal basis.

The pace of future development of our East Texas properties will depend on availability of capital, future drilling and completion results, the general economic conditions of the energy industry and on the price we receive for the natural gas and crude oil produced. Additionally, in certain areas in which we own our interest jointly with PVOG, the pace of future development will depend on PVOG's level of activity in those areas. Based on the joint development agreement, we have the ability to limit the number of rigs that PVOG operates in these areas and we have the ability to limit our participation in any PVOG well.

D.J. Basin - Niobrara

We entered the Niobrara with two transactions for approximately 40,000 net acres in southwestern Goshen, southeastern Platte and north central Laramie Counties in Wyoming, with a minimum 80% NRI. The fee leases generally have five-year primary terms, and many have options to extend the lease another five years. Approximately 20% of the total net acres are new federal leases with ten-year terms. The approximately 40,000 net acres provides us with a development potential of 250.5 net wells using four wells per 640-acre unit.

The upper Cretaceous Niobrara Formation, an over-pressured fractured shale/chalk/limestone 300' to 350' thick reservoir, is the primary target for the play. Production varies from a nearly pure oil play in the north end where the Silo Field in Laramie County is less than 1 mcf/bbl to approximately 70% gas in the southern portion in the Wattenberg Field. The Silo Field was a vertical Niobrara play discovered in the early 1980's. In the early 1990's, horizontal development (without using more recent horizontal completion techniques) increased recoveries in the Silo Field nearly ten-fold to around 225,000 barrels of oil per well. As an example, operators in the early 1990's reported single stage stimulation treatments consisting of 30,000 barrels of water pumped with wax beads as diverting material. Some horizontal wells were simple open-hole completions.

In addition to the Niobrara, the project area contains two other targets that are known producers in the DJ Basin. The Codell Sandstone formation (below the Niobrara) produced 30 million barrels of oil and 320 Bcf of gas in the Wattenberg Field. Also, the Sharon Springs Member of the Pierre Shale Formation (above the Niobrara) has produced in the Florence and Boulder Fields and has promise as an unconventional horizontal oil play.

We have participated with Devon Energy in the drilling of the Newton Ranches #14-3444H located in Goshen County Wyoming. Devon operates the well and we have a 29.2% working interest. The well has been successfully fractured and is currently on pump. Devon has proposed a second well, the Newton Ranches #3-2635H, also located in Goshen County Wyoming. We are also participating in a 3D seismic shoot which covers most of our acreage position in Goshen County, Wyoming. Additionally, we have joined consortiums and created data sharing relationships with other operators.

The Northern DJ Basin continues to exhibit considerable activity with other operators beginning to establish meaningful operations in Goshen, Laramie and Platte County, Wyoming. The majority of our 204-square mile Chugwater 3D seismic shoot that encompasses our Platte, Laramie and Goshen Counties, Wyoming leases should be completed in the first half of 2012 and a the portion already shot is currently being processed.

Summary

The number of wells we drill in 2012 will vary, and our potential capital expenditures may vary depending on the number of wells drilled, drilling and completion results, financing activities and other factors. We currently have budgeted $97 million for 2012 capital expenditures focused on continuation of our Bakken Shale horizontal drilling and other capital expenditures including capitalized interest and capitalized overhead. We expect to fund our drilling expenses primarily from existing cash as of December 31, 2011 and internal cash flows.

The following table sets forth the gross and net wells completed and brought to sales in our various basins in 2011:

	Wells Completed in 2011	
	Gross	Net
Bakken/Three Forks Horizontal - Operated	2	1.5
Bakken/Three Forks Horizontal - Non-Operated	2	0.3
Niobrara Horizontal - Non-Operated	1	0.3
Cotton Valley Vertical - Operated	1	1.0
Haynesville/Bossier Shale Horizontal-Operated	9	9.0
Total	15	12.1

Other Oil and Gas Properties

We have approximately 2,400 gross (2,100 net) acres in the Waskom Field in Caddo parish in Louisiana with five gross (2.6 net) producing wells, three of which we operate. Total reserves and production from these areas represent less than 1% of our proved reserves and 2011 production.

Oil and Gas Lease Terms and Expirations

Unless production is established within the spacing units covering the undeveloped acres on which some of our drilling locations are identified, the leases for such acreage will expire. As of December 31, 2011, we had leases representing 4,194 net acres (2,225 Bakken, 1,969 East Texas) expiring in 2012, 21,961 net acres (7,503 Bakken, 11,645 Niobrara and 2,813 East Texas) expiring in 2013 and 21,530 net acres (7,541 Bakken, 8,738 Niobrara and 5,251 East Texas) expiring in 2014. In addition, a significant portion of the acreage that we acquired in 2011 in the Bakken and Niobrara formations can be extended five additional years as allowed under the terms of the individual lease agreements.

Oil and Gas Gathering

We have, through our majority-owned subsidiary, Endeavor Gathering, gas gathering lines and compression equipment for gathering and delivery of natural gas from our core area that we operate. As of December 31, 2011, Endeavor Gathering had invested approximately $60 million in this gathering system, including the purchase of compressors and pipe inventory, which consisted of over 110 miles of gathering lines and approximately 15,000 horsepower of compressors that collect and compress gas from approximately 99% of our operated gas production from wells in our core area. At year-end 2011, this gas gathering system had takeaway capacity of 254 MMcf per day compared to our year end gross production volumes of 78.5 MMcfe per day. This system enables us to improve the control over our production and enhances our ability to obtain access to pipelines for ultimate sale of our gas. At present, Endeavor Gathering only gathers from wells in which we own an interest. Remaining gas is gathered by unrelated third parties. See "Delivery Commitments and Marketing Arrangements."

PVOG has installed and operates gathering facilities to each of the wells drilled and operated by PVOG in our jointly-owned areas. PVOG charges us a gathering fee of $0.10/MMBtu and actual cost of compression plus five percent for all gas gathered at the wellhead and redelivered to a central sales point. At year-end 2010, the PVOG gathering system had takeaway capacity of 80 MMcf per day compared to production of 20.7 MMcf per day.

We do not currently own any oil gathering pipelines or processing equipment for our Bakken or Niobrara acreage. In March 2012, we have executed a third party gas purchase agreement to transport and process the gas production from certain Bakken wells in Billings and McKenzie County, North Dakota.

Assets Held for Sale

In December 2010, the Company finalized a plan to dispose of three drilling rigs, four compressors, pipe and valves by sale. The majority of these assets, including the three drilling rigs, were disposed of throughout 2011 and the remaining assets held for sale as of December 31, 2011 consists of one compressor and various valves. These assets will either be disposed of individually or as part of a disposal group, depending on the purchaser's interest. The accounting for these assets at the plan date was in accordance with ASC 360-10, Property, Plant and Equipment. Under this guidance, the assets are carried on the balance sheet at their carrying value or fair value less cost to sell, whichever is less. Subsequent increases in fair value less cost to sell will be recognized as a gain, but not in excess of the cumulative loss previously recognized. In determining fair value for the other assets, management performed internal estimates of the value of the assets based on verbal bids gathered through their marketing efforts and other marketing information. Management also performed internal estimates on the cost to sell the assets, which primarily consisted of commissions to sell the assets, and were estimated based on past experience selling similar assets and verbal bids. As a result of determining fair value on the assets held for sale and changes in selling cost estimates, an impairment loss, net of cash proceeds of $16.2 million in 2011, was recorded for the year ended December 31, 2011 and 2010 on the assets held for sale in the amount of $9.3 million and $10.9 million, respectively, which was included in the Impairment of Oil and Natural Gas Properties and Assets Held for Sale in the Statements of Operations. As of December 31, 2011 and 2010, estimated selling costs on the remaining assets held for sale were estimated to be $0.1 million and $1.3 million, respectively.

Diamond Blue Drilling

Our subsidiary, Diamond Blue, owned three drilling rigs that were laid down in 2009 due to the Company's transition to H/B drilling. These rigs have been sold as of December 31, 2011.

Oil and Natural Gas Reserves

At December 31, 2011, our estimated total proved oil and natural gas reserves, as prepared by our independent reserve engineering firms, MHA Petroleum Consultants, Inc. ("MHA") and DeGolyer and MacNaughton ("D&M"), were approximately 285.3 Bcfe. As of December 31, 2011, D&M estimated our proved reserves related to the Haynesville/Bossier Shale to be 198.4 Bcfe, of which 78.8 Bcfe was proved developed reserves, and estimated our proved reserves related to the Bakken to be 5.0 Bcfe, of which 2.0 Bcfe was proved developed reserves. MHA estimated our remaining reserves related to other areas, including the Cotton Valley Sands, to be 81.9 Bcfe proved developed reserves. Substantially all of our proved reserves relate to our Haynesville/Bossier Shale and Cotton Valley Sands development based on SEC rules. All of our proved undeveloped reserves are on locations that are adjacent to wells productive in the same formations. As a result of the VPP sale in December 2011, volumes were reduced by 14.3 Bcfe estimated future net revenue of $55.9 million and PV-10 of $45.5 million.

In December 2008, the SEC issued its final rule, Modernization of Oil and Gas Reporting, which was effective for reporting 2009, 2010 and 2011 reserve information. In January 2010, the FASB issued its authoritative guidance on extractive activities for oil and gas to align its requirements with the SEC's final rule. We adopted the guidance as of December 31, 2009 in conjunction with our 2009 reserve reports as a change in accounting principle.

The following table shows the estimated net quantities of our proved reserves as of the dates indicated and the Estimated Future Net Revenues and Present Values attributable to total proved reserves at December 31, 2011, 2010 and 2009. All of our proved reserves are located in the United States:

	2011[2]	2010	2009
Proved Developed:			
Gas (Bcf)	155.1	157.1	124.6
Oil (MMBbls)	1.3	1.2	1.4
Total (Bcfe)	162.7	164.3	133.3
Proved Undeveloped:			
Gas (Bcf)	119.8	154.9	208.6
Oil (MMBbls)	0.4	—	2.3
Total (Bcfe)	122.6	154.9	222.0
Total Proved:			
Gas (Bcf)	274.9	312.0	333.2
Oil (MMBbls)	1.7	1.2	3.7
Total (Bcfe)	285.3	319.3	355.3
Estimated Future Net Revenues[1] ($MM)	$ 619.6	$ 692.7	$ 625.7
Present Value[1] ($MM)	$ 186.6	$ 249.9	$ 188.6
Standardized Measure ($MM)	$ 186.6	$ 249.9	$ 188.6

(1) For 2011, 2010 and 2009, prices used for Estimated Future Net Revenues and the Present Value are an average first-day of the month price for the last 12 months in accordance with recent amendments to Regulations S-K and S-X of

the SEC. Estimated Future Net Revenues and the Present Value give no effect to federal or state income taxes attributable to estimated future net revenues. The Present Value, or PV-10, represents the estimated future net cash flows attributable to our estimated proved oil and gas reserves before income tax, discounted at 10%. PV-10 may be considered a non-GAAP financial measure as defined by the SEC. We believe that the Estimated Future Net Revenue and Present Value are useful measures in addition to the standardized measure as it assists in both the determination of future cash flows of the current reserves as well as in making relative value comparisons among peer companies. See "Note M-Supplemental Information on Oil and Natural Gas Operations" in our consolidated financial statements for information about the standardized measure of discounted future net cash flows. The standardized measure is dependent on the unique tax situation of each individual company, while the pre-tax Present Value is based on prices and discount factors that are consistent from company to company. We also understand that securities analysts use this measure in similar ways.

(2) The proved reserves as of December 31, 2011 include a reduction to both volumes and revenues to reflect committed VPP volumes due for approximately 93 months. The effect of the VPP reduction to reserves and PV-10 is 14.3 Bcfe and $45.5 million, respectively.

Proved oil and natural gas reserves are the estimated quantities of crude oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are 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 recompletion.

There are numerous uncertainties inherent in estimating quantities of proved crude oil and natural gas reserves. Crude oil and natural gas engineering is a subjective process of estimating underground accumulations of crude oil and natural gas that cannot be precisely measured. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing and production subsequent to the date of the estimate may justify revision of such estimate. Accordingly, reserve estimates are often different from the quantities of crude oil and natural gas that are ultimately recovered.

In accordance with the guidelines of the SEC, our independent reserve engineer's estimates for 2010 and 2011 of future net revenues from our properties, and the PV-10 and standardized measure thereof, were determined to be economically producible under existing economic conditions, which requires the use of the 12-month average price for each product, calculated as the simple arithmetic average of the first-day-of-the-month price for the period January through December, except where such guidelines permit alternate treatment, including the use of fixed and determinable contractual price escalations. For 2010 and 2011, the average prices used in such estimates were $4.38 and $4.12 per MMbtu of natural gas and $79.43 and $96.19 per Bbl of crude oil, respectively. These prices do not include the impact of hedging transactions, nor do they include applicable transportation and quality differentials, nor price differentials between natural gas liquids and oil, which are deducted from or added to the index prices on a well by well basis.

The following table shows our total 2011 and 2010 proved reserves by area:

Proved Reserves-2011 SEC Pricing (2) (3)

Area	Oil (MMBbl)	Natural Gas (Bcf)	Total (Bcfe)	% Proved Developed	PV-10(1) ($ in millions)
Bakken/Three Forks	0.7	0.3	5.0	39%	$ 14.4
Cotton Valley Sands & Other	1.0	76.2	81.9	100%	$ 99.3
Haynesville/Bossier Shale	—	198.4	198.4	40%	$ 72.9
Total	1.7	274.9	285.3	57%	$ 186.6

Proved Reserves-2010 SEC Pricing(2)

Area	Oil (MMBbl)	Natural Gas (Bcf)	Total (Bcfe)	% Proved Developed	PV-10(1) ($ in millions)
Bakken/Three Forks	—	—	—	—	$ —
Cotton Valley Sands & Other	1.2	77.8	85.2	100%	$ 98
Haynesville/Bossier Shale	—	234.1	234.1	34%	$ 151.9
Total	1.2	311.9	319.3	51%	$ 249.9

(1) PV-10 represents the present value, discounted at 10% per annum, of estimated future net revenue before income tax of the Company's estimated proved reserves. The PV-10 value is different than the standardized measure of discounted estimated future net cash flows, which is calculated after income taxes. The Company believes the PV-10 is a useful measure for evaluating the relative monetary significance of their proved reserves. Investors may use the PV-10 as a basis for comparison of the relative size and value of the Company's reserves to its peers.

(2) The proved reserves as of December 31, 2011 and 2010 are calculated based on current SEC guidelines. The commodity prices used in the estimate were based on the 12-month unweighted arithmetic average of the first-day-of-the-month price during the period from January through December. For natural gas volumes, the average Henry Hub spot price of $4.12 and $4.38 for 2011 and 2010, respectively, per million British thermal units (MMBTU) and was adjusted for energy content, transportation fees, regional price differences, and system shrinkage. For crude oil, the average West Texas Intermediate posted price of $96.19 and $79.43 for 2011 and 2010, respectively, per barrel and was adjusted for quality, transportation fees, and regional price differentials.

(3) The proved reserves as of December 31, 2011 include a reduction to both volumes and revenues to reflect committed VPP volumes due for approximately 94 months. The effect of the VPP reduction to reserves and PV-10 is 14.3 Bcfe and $45.5 million, respectively.

The amendments to Regulations S-K and S-X of the SEC also revised the guidelines for reporting proved undeveloped reserves. Reserves may be classified as proved undeveloped if there is a high degree of confidence that the quantities will be recovered, and they are scheduled to be drilled within five years of their initial inclusion as proved reserves, unless specific circumstances justify a longer time. In addition, proved undeveloped reserves may be estimated through the use of reliable technology in addition to flow tests and production history.

Approximately 43% of our year-end 2011 proved reserves are undeveloped under SEC rules. During 2011, we drilled and completed 8 of the 35 proven undeveloped locations included in our year-end 2010 reserve reports. At the end of 2009, we, like other operators, reviewed all our existing proved undeveloped reserves in light of the SEC's five-year rule and decided to remove 53 Bcfe of proved undeveloped reserves in the Cotton Valley Sand vertical drilling opportunities, where we had 30% working interests in non-operated locations. At December 31, 2010, due to the horizontal drilling opportunities we had in the Haynesville/Bossier Shale and in the oil resource plays of the Bakken and Niobrara, we removed our remaining 219.6 Bcfe of operated Cotton Valley Sand vertical drilling of proved undeveloped reserves to comply with the SEC's five-year rule. None of the Cotton Valley Sands locations were actually beyond the five-year limit, but would have presented scheduling and capital priority issues under the SEC guidelines going forward, especially in the context of our focus on the Haynesville/Bossier Shale, Bakken, and Niobrara horizontal drilling opportunities. We still believe the removed proven undeveloped Cotton Valley Sand locations to be geologically and economically viable, especially if drilled horizontally. If the price environment should improve, we could consider accelerating these resource development opportunities.

Our proved undeveloped reserves of 122.6 Bcfe at December 31, 2011 correspond to 25 net (27 gross) Haynesville/ Bossier Shale horizontal drilling locations (119.8 Bcfe) in our core area that are planned to be drilled within the next four years (2.7 rig years of inventory) and 1.8 net Bakken horizontal wells that are currently being drilled or waiting on completion (502,000 BOE or 3.0 Bcfe). In July 2011, we temporarily suspended drilling new Haynesville/Bossier horizontal wells to focus our capital on accelerating the development of our oil acreage. We anticipate reactivating our Haynesville/Bossier drilling program by October 2014 to continue development of our natural gas reserves in our primary development area in East Texas. If natural gas prices were to increase and/or Haynesville/Bossier completed well costs were to decline, we would consider accelerating our Haynesville/Bossier development.

The quantity and value of our proved undeveloped Haynesville/Bossier Shale and Bakken reserves are dependent upon our ability to fund the associated development costs, which were estimated to be $257.2 million in the aggregate as of December 31, 2011 of which $224.8 million was related to Haynesville/Bossier proved undeveloped locations. The estimated future development costs do not include our 2012 estimated exploration costs related to our Bakken drilling program, which is estimated to be approximately $68 million (7.1 net wells) in addition to $29 million of expenditures related to seismic in the Niobrara and capitalized interest and related G&A expense.

We have examined all sources of available funding, including our expected operating cash flows, equity issuances and potential joint venture opportunities, and we are reasonably certain that we will be able to fund the necessary development costs for our proved undeveloped reserves over the next four years. We have a track record of successfully raising capital to fund our drilling plan. With our current capital structure and limitations under our Senior Secured Notes indenture, we expect to look primarily to the equity markets to fund our Haynesville/Bossier drilling plan. The Company's stock price has historically been highly correlated to the price of natural gas. With our having valuable natural gas assets (Haynesville/Bossier and liquids-rich Cotton Valley) and a fully developed infrastructure, we believe an upward move in natural gas price would have a significant increase in our stock price. In addition to potentially issuing equity to fund our drilling program, we could sell assets and/or potentially seek a JV partner to assist in development.

Our estimates of proved reserves, related future net revenues and PV-10 at December 31, 2009, 2010 and 2011 of our Cotton Valley Sands development reserves were prepared by our independent petroleum consultant, MHA, in accordance with generally accepted petroleum engineering and evaluation principles and definitions and guidelines established by the SEC. The primary person responsible for the reserve estimates prepared by MHA is Mr. John Arsenault. Mr. Arsenault is a Vice President with MHA and has approximately 25 years of direct industry engineering experience, 11 of which have been specifically related to reserves estimation. He obtained a B. Sc. in Petroleum Engineering from the Colorado School of Mines in 1985 and is a member of the Society of Petroleum Engineers.

Our estimates of proved reserves and related future net revenues and PV-10 at December 31, 2010 and 2011 with respect to our Haynesville/ Bossier Shale and our Bakken reserves are based on reports prepared by D&M, our independent reserve engineer, in accordance with generally accepted petroleum engineering and evaluation principles and definitions and current guidelines established by the SEC. D&M is a Delaware corporation with offices in Dallas, Houston, Calgary and Moscow. The firm's more than 100 professionals include engineers, geologists, geophysicists, petrophysicists and economists engaged in the appraisal of oil and gas properties, evaluation of hydrocarbon and other mineral prospects, basin evaluations, comprehensive field studies and equity studies related to the domestic and international energy industry. These services have been provided for over 70 years. D&M restricts its activities exclusively to consultation; it does not accept contingency fees, nor does it own operating interests in any oil, gas or mineral properties, or securities or notes of clients. The firm subscribes to a code of professional conduct, and its employees actively support their related technical and professional societies. The Senior Vice President at D&M primarily responsible for overseeing the preparation of the reserve estimates is a Registered Petroleum Engineer in the State of Texas with more than 36 years of experience in oil and gas reservoir studies and reserve evaluations. He graduated with a Bachelor of Science degree in Petroleum Engineering from Texas A&M University in 1974 and he is a member of the International Society of Petroleum Engineers and the American Association of Petroleum Geologists. The firm is a Texas Registered Engineering Firm.

Technology used to establish proved reserves

Under current SEC rules, proved reserves are those quantities of oil and natural gas, which, by analysis of geoscience 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. The term "reasonable certainty" implies a high degree of confidence that the quantities of oil and/or natural gas actually recovered will equal or exceed the estimate. Reasonable certainty can be established using techniques that have been proved effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that have been field tested and have been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

In order to establish reasonable certainty with respect to our estimated proved reserves, D&M and MHA employed technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used in the estimation of our proved reserves include, but are not limited to, electrical logs, radioactivity logs, core analyses, geologic maps and available down hole and production data, seismic data and well test data. Reserves attributable to producing wells with sufficient production history were estimated using appropriate decline curves or other performance relationships. Reserves attributable to producing wells with limited production history and for undeveloped locations were estimated using performance from analogous wells in the surrounding area and geologic data to assess the reservoir continuity.

Internal controls over reserves estimation process.

Our policies and practices regarding internal control over the estimating of reserves are structured to objectively and accurately estimate our oil and natural gas reserves quantities and present values in compliance with the SEC's regulations and U.S. Generally Accepted Accounting Principles. We maintain an internal staff of petroleum engineers and geosciences professionals who work closely with our independent petroleum consultant and our independent reserve engineer to ensure the integrity, accuracy and timeliness of data furnished to MHA and to D&M in their reserves estimation process. Inputs to our reserves estimation process are based on historical results for production history, oil and natural gas prices, lease operating expenses, development costs, ownership interest and other required data. Our technical team meets regularly with representatives of MHA and D&M to review properties and discuss methods and assumptions used in MHA's and D&M's preparation of the year-end reserves estimates. While we have no formal committee specifically designated to review reserve reporting and the reserves estimation process, our senior management reviews and approves the MHA and D&M reserve reports and any internally estimated significant changes to our proved reserves on a timely basis. For the 2011 reserve report, our Audit Committee discussed the results of the reserve reports with Senior Management. The Audit Committee will conduct similar reviews on an annual basis.

Our Vice President-Geosciences, Timothy Benton, was the technical person within the Company primarily responsible for overseeing the preparation of our year-end 2011 reserves estimates. Mr. Benton has over 30 years of industry experience in engineering and reservoir evaluations. He is a Registered Professional Engineer in the state of Oklahoma, a member of the Society of Petrophysics & Well Log Analysts and a member of the Society of Petroleum Engineers. Mr. Benton reports directly to our Chief Executive Officer and our President.

No estimates of our proved reserves comparable to those included in this report have been included in reports to any federal agency other than the SEC.

Acquisition, Exploration and Development Costs

The following table shows certain information regarding the costs incurred by us in our acquisition, exploration and development activities during the periods indicated.

	2011	2010	2009
		(in thousands)	
Development and exploration costs:			
Development drilling	$ 80,305	$ 7,788	$ 14,202
Exploratory drilling	42,479	164,355	116,250
Tubular and other drilling inventories	1,068	3,167	1,697
Asset retirement obligation	418	706	565
	124,270	176,016	132,714
Acquisition:			
Proved	4,893	3,884	6,881
Unproved	153,059	8,149	11,450
	157,952	12,033	18,331
Total	$ 282,222	$ 188,049	$ 151,045

Oil and Natural Gas Production, Production Prices and Production Costs

For a summary of our oil and natural gas production, prices and production costs, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations- Summary Operating and Reserve Data," which is incorporated by reference into this Item.

Drilling Activity

We drilled or participated in the drilling of wells as set out in the table below for the periods indicated. The table was completed based upon the date the wells were completed regardless of when drilling was initiated. You should not consider the results of prior drilling activities as necessarily indicative of future performance, nor should you assume that there is necessarily any correlation between the number of productive wells drilled and the oil and natural gas reserves generated by those wells. All of the following wells were drilled in the United States.

	Year Ended December 31,					
	2011		2010		2009	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Natural Gas	8.0	8.0	1.0	1.0	6.0	6.0
Exploratory wells:						
Oil	5.0	2.1	—	—	—	—
Natural Gas	2.0	2.0	20.0	17.3	11.0	10.9
Total	15.0	12.1	21.0	18.3	17.0	16.9

As of December 31, 2009, we had two gross and net Haynesville/Bossier Shale horizontal wells drilling that are not included in the table above. These wells were considered exploratory wells as they were not identified as proved undeveloped locations in a prior year reserve report.

Acreage

The following table shows our developed and undeveloped oil and natural gas lease and mineral acreage as of December 31, 2011.

	Developed		Undeveloped		Total	
Basin and State	Gross	Net	Gross	Net	Gross	Net
East Texas, Texas	41,424	28,407	16,305	10,145	57,729	38,552
Bakken, Montana and North Dakota	1,888	1,099	58,569	34,276	60,457	35,375
Niobrara, Wyoming	—	—	52,376	40,082	52,376	40,082
Other (United States)	—	—	320	240	320	240
Total	43,312	29,506	127,570	84,743	170,882	114,249

The following table provides Bakken and Niobrara acreage by state and county as of December 31, 2011:

Basin and State	County	Total Net Acres	% of GMX Acres in Basin
Williston Basin (Bakken/Three Forks)			
North Dakota	Stark	9,441	27%
	McKenzie	7,117	20%
	Billings	10,155	29%
	Dunn	1,022	3%
Total North Dakota		27,735	79%
Montana	Richland	6,039	17%
	Sheridan	1,280	3%
	Wibaux	321	1%
Total Montana		7,640	21%
Total Williston Basin (Bakken/Three Forks)		35,375	100%
DJ Basin (Niobrara)			
Wyoming	Laramie	21,901	55%
	Goshen	12,687	32%
	Platte	5,494	13%
Total DJ Basin (Niobrara)		40,082	100%
Total Acquisitions		75,457	

Title to oil and natural gas acreage is often complex. Landowners may have subdivided interests in the mineral estate. Oil and natural gas companies frequently subdivide the leasehold estate to spread drilling risk and often create overriding royalties. When we purchased the properties, the purchase included title opinions prepared by counsel analyzing mineral ownership in each well drilled. Further, for each producing well there is a division order signed by the current recipients of payments from production stipulating their assent to the fraction of the revenues they receive. We obtain similar title opinions with respect to each new well drilled. While these practices, which are common in the industry, do not assure that there will be no claims against title to the wells or the associated revenues, we believe that we are within normal and prudent industry practices. Because many of the properties in our current portfolio were purchased out of bankruptcy in 1998, we have the advantage that any known or unknown liens against the properties were cleared in the bankruptcy.

Productive Well Summary

The following table shows the number of productive wells in which we had interests as of December 31, 2011. Gross oil and natural gas wells include wells with multiple completions. Wells with multiple completions are counted only once for purposes of the following table.

	Productive Wells	
	Gross	Net
Natural gas	369.0	236.2
Oil	21.0	15.6
Total	390.0	251.8

A substantial portion of our productive wells are related to our Cotton Valley Sands development.

Facilities

As of December 31, 2011, we lease the following office space:

- 32,458 square feet in Oklahoma City, Oklahoma for our corporate headquarters. The annual rental cost is approximately $487,000.

- 1,875 square feet of office space in Marshall, Texas used primarily for our east Texas land field operations. The annual rent is approximately $20,000.
- 4,803 square feet of office space in Denver, Colorado used primarily for our land and field operations for our Niobrara/Bakken operations. The annual rental cost is approximately $100,000.

We also own a 50-acre operations field yard approximately seven miles southeast of Marshall, Texas that has approximately 21,500 square feet of office and warehouse space, 48 acres on which our gas gathering sales point is located and 100 acres for expansion of our field operations near Marshall, Texas. In 2008, we opened a second field office of approximately 2,400 square feet dedicated to land operations situated on 14 acres approximately two miles from the operations field yard.

Employees

As of December 31, 2011, we had 112 full-time employees. This compares to 109 full-time employees at December 31, 2010. We also use a number of independent contractors to assist in land and field operations. We believe our relations with our employees are satisfactory. Our employees are not covered by a collective bargaining agreement.

Delivery Commitments and Marketing Arrangements

Our ability to market oil and natural gas often depends on factors beyond our control. The potential effects of governmental regulation and market factors, including alternative domestic and imported energy sources, available pipeline capacity, and general market conditions, are not entirely predictable.

Natural Gas. Natural gas is generally sold pursuant to individually negotiated gas purchase contracts, which vary in length from spot market sales of a single day to term agreements that may extend several years. None of our current contracts require us to provide a fixed and determinable quantity of gas. However, we do have a gas transportation and a gas marketing contract that charges us a reservation fee. Customers who purchase natural gas include marketing affiliates of the major oil and gas companies, pipeline companies, natural gas marketing companies, and a variety of commercial and public authorities, industrial, and institutional end-users who ultimately consume the gas. Gas purchase contracts define the terms and conditions unique to each of these sales. The price received for natural gas sold on the spot market may vary daily, reflecting changing market conditions. The deliverability and price of natural gas are subject to both governmental regulation and supply and demand forces.

Substantially all of our gas from our East Texas company-operated wells is initially sold to our wholly owned subsidiary, Endeavor Pipeline, which in turn sells gas to unrelated third parties. All of our gas is currently sold under contracts providing for market sensitive terms that are terminable with 30-60 day notice by either party without penalty. This means that we both enjoy the benefits of high prices in increasing price markets and suffer the impact of low prices when gas prices decline. In addition, PVOG markets 100% of the gas produced from wells operated by PVOG in areas we jointly own. A subsidiary of PVOG charges us a marketing fee of 1% of the sales proceeds subject to certain price caps for oil and natural gas sold on our behalf in areas we jointly own.

In June 2009, we entered into a firm sales agreement for 15,000 MMBtu per day increasing to 100,000 MMBtu per day through May 2014 at a price equal to the NGPL Tx-Ok index minus $0.02 per MMBtu. If we do not deliver physical gas, we have to pay a $0.02 per MMBtu deficiency fee on volumes not delivered. We sell a commingled package of gas owned by the Company, other working interest owners, and royalty owners under this agreement.

On February 1, 2010, we began shipping gas from east Texas to Perryville, Louisiana on the Regency pipeline under a ten-year firm transportation agreement in which we reserved 50,000 MMBtu per day of firm capacity; we pay a demand fee of $0.30 per MMBtu per day, and pay variable shipping fees equal to $0.05 per MMBtu plus the pipeline retains 1.0% fuel on volumes of gas that flow under our firm agreement. We ship a commingled package of gas owned by the Company, other working interest owners, and royalty owners under this agreement.

On February 1, 2010, as we began shipping gas on the Regency pipeline, we also began shipping gas on the Gulf States pipeline under a ten-year firm transportation agreement in which we reserved 35,000 MMBtu per day of firm capacity; we pay a demand fee of $0.0151 per MMBtu per day, and pay variable shipping fees equal to $0.0019 per MMBtu; there is no fuel retained by the pipeline under our firm agreement. We ship a commingled package of gas owned by the Company, other working interest owners, and royalty owners under this agreement.

In 2011, our largest purchaser of natural gas was Texla Energy Management, Inc. which accounted for over 48% of total natural gas sales. Other customers that accounted for 10% or more of our 2011 total natural gas sales were Southwest Energy L.P. and ConocoPhillips Company. We do not believe that the loss of any of our purchasers would have a material adverse effect on our operations as there are other purchasers active in the market.

Crude Oil. Oil produced from our properties is sold at the prevailing field price to one or more of a number of unaffiliated purchasers in the area. Generally, purchase contracts for the sale of oil are cancelable on 30 days' notice. The price paid by these purchasers is an established market or "posted" price that is offered to all producers. In 2011, our largest purchaser of crude oil was Sunoco, Inc., which accounted for 62% of crude oil sales. Various purchasers through Penn Virginia Oil & Gas, L.P. accounted for 30% of our sales of crude oil.

We do not believe that the loss of any of our purchasers would have a material adverse effect on our operations as there are other purchasers active in the market.

Competition

We compete with major integrated oil and natural gas companies and independent oil and natural gas companies in all areas of operation. In particular, we compete for property acquisitions and for the equipment and labor required to operate and develop these properties. Most of our competitors have substantially greater financial and other resources than we have. In addition, larger competitors may be able to absorb the burden of any changes in federal, state and local laws and regulations more easily than we can, which could adversely affect our competitive position. These competitors may be able to pay more for exploratory prospects and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than we can. Further, our competitors may have technological advantages and may be able to implement new technologies more rapidly than we can. Our ability to explore for natural gas and oil prospects and to acquire additional properties in the future will depend on our ability to conduct operations, to evaluate and select suitable properties and to consummate transactions in this highly competitive environment. In addition, most of our competitors have operated for longer than we have and have demonstrated the ability to operate through industry cycles.

Availability of Supplies and Materials

At various times, we have and may continue to experience occasional or prolonged shortages or unavailability of drilling rigs, drill pipe and other material used in oil and natural gas drilling. Such unavailability could result in increased costs, delays in timing of anticipated development or cause interests in undeveloped oil and natural gas leases to lapse.

Regulation

Exploration and Production. The exploration, production and sale of oil and natural gas are subject to various types of local, state and federal laws and regulations. These laws and regulations govern a wide range of matters, including the drilling and spacing of wells, allowable rates of production, restoration of surface areas, plugging and abandonment of wells and requirements for the operation of wells. Our operations are also subject to various conservation requirements. These include the regulation of the size and shape of drilling and spacing units or proration units and the density of wells that may be drilled and the unitization or pooling of oil and natural gas properties. In this regard, some states allow forced pooling or integration of tracts to facilitate exploration, while other states rely on voluntary pooling of lands and leases. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas and impose certain requirements regarding the ratability of production. All of these regulations may adversely affect the rate at which wells produce oil and natural gas and the number of wells we may drill. All statements in this report about the number of locations or wells reflect current laws and regulations.

The failure to comply with these rules and regulations can result in substantial penalties. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

Environmental, Health and Safety Matters. We are subject to various federal, regional, state and local laws and regulations governing health and safety, the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may, among other things, require the acquisition of permits to conduct exploration, drilling and production operations; govern the amounts and types of substances that may be released into the environment in connection with oil and gas drilling and production; restrict the way we handle or dispose of our materials and wastes; limit or prohibit construction or drilling activities in sensitive areas such as wetlands, wilderness areas or areas inhabited by endangered or threatened species; require investigatory and remedial actions to mitigate pollution conditions caused by our operations or attributable to former operations; and impose obligations to reclaim any abandoned well sites and pits. These laws and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and gas industry increases the cost of doing business in the industry and consequently affects profitability. Compliance with these laws and regulations requires expenditures of time and financial resources, and failure to comply with these laws, regulations and permits may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations and the issuance of orders enjoining some or all of our operations in affected areas. While we believe that compliance with current requirements will not have a material adverse effect on our financial condition or results of operations, there is no assurance that changes in environmental requirements for the interpretation or enforcement of them will not have a material adverse effect.

Natural gas, oil or other pollutants, including salt water brine, may be discharged in many ways, including from a well or drilling equipment at a drill site, leakage from pipelines or other gathering and transportation facilities, leakage from storage tanks and sudden discharges from damage or explosion at natural gas facilities or oil and natural gas wells. Discharged hydrocarbons may migrate through soil to water supplies or adjoining property, giving rise to additional liabilities. Accidental releases or spills of substances may occur in the course of our operations, and we cannot assure you that we will not incur significant costs and liabilities as a result of such releases or spills, including any third party claims for damage to property, natural resources or persons.

Additionally, federal and state legislatures and government agencies frequently revise environmental, health and safety laws and regulations, and any changes that result in more stringent and costly compliance, waste handling, disposal, cleanup and remediation requirements for the oil and gas industry could have a significant impact on our operating costs. The trend in environmental regulation has been to place more restrictions and limitations on activities that may affect the environment, and thus, any changes in environmental laws and regulations or re-interpretation of enforcement policies that result in more stringent and costly waste handling, storage, transport, disposal, emissions or remediation requirements could have a material adverse effect on our operations and financial position. We may be unable to pass on such increased compliance costs to our customers.

The following is a summary of the more significant existing environmental, health and safety laws and regulations to which our business operations are subject and for which compliance may have a material adverse impact on our capital expenditures, results of operations or financial position.

The federal Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the "superfund law," imposes liability, often regardless of fault or the legality of the original conduct, on some classes of persons that are considered to have contributed to the release of a "hazardous substance" into the environment. These persons include the present and past owner or operator of a disposal site or sites where the release occurred or sites affected by the release, and persons that dispose or arrange for disposal of hazardous substances. Persons who are or were responsible for releases of hazardous substances under CERCLA may be subject to joint and severable liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. Many states have analogous programs assigning liability for the release of hazardous substances. Notwithstanding the petroleum exclusion, we could be subject to the liability under CERCLA or state analogues because our drilling and production activities generate waste that may be subject to classification as hazardous substances under CERCLA.

The federal Resource Conservation and Recovery Act of 1976, as amended ("RCRA"), is the principal federal statute governing the treatment, storage and disposal of hazardous wastes. RCRA imposes stringent operating and waste handling requirements, and imposes liability for failure to meet such requirements, on a person who is a "generator" or "transporter" of hazardous waste or an "owner" or "operator" of a hazardous waste treatment, storage or disposal facility. At present, RCRA includes a statutory exemption that allows most oil and natural gas exploration and production waste to be classified as nonhazardous waste. A similar exemption is contained in many of the state-law counterparts to RCRA. As a result, we are not required to comply with a substantial portion of RCRA's requirements because our operations generate exempt quantities of hazardous wastes. However, at various times in the past, proposals have been made to amend RCRA to rescind the exemption that excludes oil and natural gas exploration and production wastes from regulation as hazardous waste. Repeal or modification of the exemption by administrative, legislative or judicial process, or modification of similar exemptions in applicable state statutes, could increase the volume of hazardous waste we are required to manage and dispose of and could cause us to incur increased operating expenses.

The federal Water Pollution Control Act of 1972, as amended ("Clean Water Act"), and analogous state laws, impose restrictions and strict controls regarding the discharge of pollutants into certain water bodies. Pursuant to the Clean Water Act and analogous state laws, permits must be obtained to discharge pollutants into waters of the United States or, under state law, state surface or subsurface waters. Any such discharge of pollutants into regulated waters must be performed in accordance with the terms of a permit issued by the EPA or the analogous state agency. Spill prevention, control and countermeasure requirements under federal law require appropriate operating protocols including containment berms and similar structures to help prevent the contamination of regulated waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. In addition, the Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities or during construction activities.

Our operations employ hydraulic fracturing techniques to stimulate natural gas production from unconventional geological formations, which entails the injection of pressurized fracturing fluids (consisting of water, sand and certain chemicals) into a well bore. The federal Energy Policy Act of 2005 amended the Underground Injection Control ("UIC") provisions of the federal Safe Drinking Water Act ("SDWA") to exclude hydraulic fracturing from the definition of "underground injection" under certain circumstances. However, the repeal of this exclusion has been advocated by certain advocacy organizations and others in the public. Legislation to amend the SDWA to repeal this exemption and require federal permitting and regulatory control of hydraulic fracturing, as well as legislative proposals to require disclosure of the chemical constituents of the fluids used in the fracturing process, were proposed in recent sessions of Congress. Similar legislation could be introduced in the current session of Congress, which commenced on January 3, 2011. Scrutiny of hydraulic fracturing activities continues in other ways, with the EPA having commenced a study of the potential environmental impacts of hydraulic fracturing, the results of which are anticipated to be available by late 2012. Last year, a committee of the U.S. House of Representatives commenced investigations into hydraulic fracturing practices. The U.S. Department of the Interior has announced that it will consider regulations relating to the use of hydraulic fracturing techniques on public lands and disclosure of fracturing fluid constituents. In addition, some states and localities have adopted, and others are considering adopting, regulations or ordinances that could restrict hydraulic fracturing in certain circumstances, or that would impose higher taxes, fees or royalties on natural gas production. For example, New York has imposed a de facto moratorium on the issuance of permits for certain hydraulic fracturing practices until an environmental review and potential new regulations are finalized, which will at the earliest be spring 2012. Significant controversy has surrounded drilling operations in Pennsylvania. Wyoming, Colorado, Arkansas, and Texas have adopted rules requiring drilling operators conducting hydraulic fracturing activities in those states to publicly disclose the chemicals used in the fracturing process. If new federal or state laws or regulations that significantly restrict hydraulic fracturing are adopted, such legal requirements could result in delays, eliminate certain drilling and injection activities, make it more difficult or costly for us to perform fracturing and increase our costs of compliance and doing business. It is also possible that our drilling and injection operations could adversely affect the environment, which could result in a requirement to perform investigations or clean-ups or in the incurrence of other unexpected material costs or liabilities.

The Oil Pollution Act of 1990, as amended ("OPA"), which amends the Clean Water Act, establishes strict liability for owners and operators of facilities that are the site of a release of oil into waters of the United States. The OPA and its associated regulations impose a variety of requirements on responsible parties related to the prevention of oil spills and liability for damages resulting from such spills. A "responsible party" under the OPA includes owners and operators of certain onshore facilities from which a release may affect regulated waters.

The Federal Clean Air Act, as amended ("Clean Air Act"), and state air pollution permitting laws, restrict the emission of air pollutants from many sources, including processing plants and compressor stations and potentially from our drilling and production operations, and as a result affects oil and natural gas operations. We may be required to incur compliance costs or capital expenditures for existing or new facilities to remain in compliance. In addition, more stringent regulations governing emissions of air pollutants, including greenhouse gases such as methane (a component of natural gas) and carbon dioxide ("CO_2") are being developed by the federal government, and may increase the costs of compliance for some facilities or the cost of transportation or processing of produced oil and gas which may affect our operating costs. Obtaining permits has the potential to delay the development of oil and natural gas projects. While we may be required to incur certain capital expenditures in the next few years for air pollution control equipment or other air emissions-related issues, we do not believe, based on current law, that such requirements will have a material adverse effect on our operations.

In response to findings that emissions of carbon dioxide, methane and other greenhouse gases from industrial and energy sources contribute to increases of carbon dioxide levels in the earth's atmosphere and oceans and cause global warming, effects on climate, and other environmental effects and therefore present an endangerment to public health and the environment, the EPA has adopted various regulations under the federal Clean Air Act addressing emissions of greenhouse gases that may affect the oil and gas industry. On November 8, 2010, the EPA finalized rules expanding its Mandatory Greenhouse Gas Reporting Rule, originally promulgated in October 2009, to be applicable to the oil and natural gas industry, including certain onshore oil and natural gas production activities, which may affect certain of our existing or future operations and require the inventory and reporting of emissions. In addition, EPA has taken the position that existing Clean Air Act provisions require an assessment of greenhouse gas emissions within the permitting process for certain large new or modified stationary sources under EPA's Prevention of Significant Deterioration ("PSD") and Title V permit programs beginning in 2011. Facilities triggering permit requirements may be required to reduce greenhouse gas emissions consistent with "best available control technology" standards if deemed to be cost-effective. Such changes will affect state air permitting programs in states that administer the federal Clean Air Act under a delegation of authority, including states in which we have operations. In the last Congress, numerous legislative measures were introduced that would have imposed restrictions or costs on greenhouse gas emissions, including from the oil and gas industry. It is uncertain whether similar measures will be introduced in, or passed by, the new Congress which convened in January 2012. In addition, the United States has been involved in international negotiations regarding greenhouse gas reductions under the United Nations Framework Convention on Climate Change. In addition, certain U.S. states or regional coalitions of states have adopted measures regulating or limiting greenhouse gases from certain sources or have adopted policies seeking to reduce overall emissions of greenhouse gases. The adoption and implementation of any international treaty, of federal or state legislation or regulations, imposing reporting obligations on, or limiting emissions of greenhouse gases from, our equipment and operations could require us to incur costs to comply with such requirements and possibly require the reduction or limitation of emissions of greenhouse gases associated with our operations and other sources within the industrial or energy sectors. Such legislation or regulations could adversely affect demand for the oil and natural gas we produce or the cost of transportation and processing our products. Finally, it should be noted that some scientists have concluded that increasing concentrations of greenhouse gases may produce changes in climate or weather, such as increased frequency and severity of storms, floods and other climatic events, which if any such effects were to occur, could have adverse physical effects on our exploration and production operations or associated infrastructure or disrupt markets for our products.

The federal Endangered Species Act, as amended ("ESA"), and comparable state laws, may restrict activities that affect endangered and threatened species or their habitats. Some of our facilities may be located in areas that are designated as habitat for endangered or threatened species. The designation of previously unidentified endangered or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas. For example, the Sand Dune Lizard, Lesser Prairie Chicken, Sage Grouse and certain wildflower species have been proposed for listing and are currently under review by the U.S. Fish & Wildlife Service ("FWS").

We are subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act, as amended ("OSHA"), and comparable state laws, whose purpose is to protect the health and safety of workers. In addition, the OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. These laws and provisions of CERCLA require reporting of spills and releases of hazardous chemicals in certain situations.

We do not believe that our environmental, health and safety risks will be materially different from those of comparable U.S. companies in the oil and natural gas industry. Nevertheless, there can be no assurance that such environmental, health and safety laws and regulations will not result in a curtailment of production or material increase in the cost of production, development or exploration or otherwise adversely affect our capital expenditures, financial condition and results of operations.

In accordance with industry practice, we maintain insurance against some, but not all, potential operating losses including environmental liabilities, and some environmental risks generally are not fully insurable. For some operating risks, we may not obtain insurance if we believe the cost of available insurance is excessive relative to the risks presented. If a significant operating accident or other event occurs and is not fully covered by insurance, it could adversely affect the profitability or viability of the Company.

In addition, because we have acquired and may acquire interests in properties that have been operated in the past by others, we may be liable for environmental damage, including historical contamination, caused by such former operators. Additional liabilities could also arise from continuing violations or contamination not discovered during our assessment of the acquired properties.

Natural Gas Marketing and Transportation. Our sales of natural gas are affected by the availability, terms and cost of transportation. The price and terms for access to pipeline transportation are subject to extensive federal and state regulation. From 1985 to the present, several major regulatory changes have been implemented by Congress and the Federal Energy Regulatory Commission ("FERC"). The FERC regulates interstate natural gas transportation rates, and terms and conditions of service, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas. Since 1985, the FERC has endeavored to make natural gas transportation more accessible to natural gas buyers and sellers on an open and non-discriminatory basis. Beginning in 1992, the FERC issued a series of orders, beginning with Order No. 636, to implement its open access policies. As a result, the interstate pipelines' traditional role of providing the sale and transportation of natural gas as a single service has been eliminated and replaced by a structure under which pipelines provide transportation and storage service on an open access basis to others who buy and sell natural gas. Although the FERC's orders do not directly regulate natural gas producers, they are intended to foster increased competition within all phases of the natural gas industry.

In 2000, the FERC issued Order No. 637 and subsequent orders, which imposed a number of additional reforms designed to enhance competition in natural gas markets. Among other things, Order No. 637 revised the FERC's pricing policy by waiving price ceilings for short-term released capacity for a two-year experimental period, and effected changes in FERC regulations relating to scheduling procedures, capacity segmentation, penalties, rights of first refusal and information reporting.

In addition, the FERC is continually proposing and implementing new rules affecting segments of the natural gas industry, most notably interstate natural gas transmission companies, that remain subject to FERC's jurisdiction. These initiatives may also affect the intrastate transportation of gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry and these initiatives generally reflect more light-handed regulation.

The natural gas industry historically has been very heavily regulated. Therefore, we cannot provide any assurance that the less stringent regulatory approach established by the FERC under Order No. 637 will continue. However, we do not believe that any action taken will affect us in a way that materially differs from the way it affects other natural gas producers, gatherers and marketers with which we compete.

The price at which we sell natural gas is not currently subject to federal rate regulation and, for the most part, is not subject to state regulation. However, with regard to our physical sales of these energy commodities, we are required to observe anti-market manipulation laws and related regulations enforced by the FERC, the Commodity Futures Trading Commission, or the CFTC and/or the Federal Trade Commission, or the FTC. Please see below the discussion of "Other Federal Laws and Regulations Affecting Our Industry—Energy Policy Act of 2005." Should we violate the anti-market manipulation laws and regulations, we could also be subject to related third party damage claims by, among others, sellers, royalty owners and taxing authorities.

Crude Oil Marketing and Transportation. Our sales of crude oil and condensate are currently not regulated and are made at market prices. Nevertheless, Congress could reenact price controls in the future.

Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any way that is materially different from those of our competitors who are similarly situated.

Further, intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all similarly situated shippers requesting service on the same terms and under the same rates. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our similarly situated competitors.

Other Federal Laws and Regulations Affecting Our Industry

Energy Policy Act of 2005. On August 8, 2005, President Bush signed into law the Energy Policy Act of 2005, or the EPAct 2005. Among other matters, EPAct 2005 amends the NGA to add an anti-manipulation provision which makes it unlawful for any entity to engage in prohibited behavior prescribed by the FERC. EPAct 2005 also provides the FERC with the power to assess civil penalties of up to $1,000,000 per day for violations of the NGA and increases the FERC's civil penalty authority under the NGPA from $5,000 per violation per day to $1,000,000 per violation per day. The civil penalty provisions are applicable to entities that engage in the sale of natural gas for resale in interstate commerce. On January 19, 2006, the FERC issued Order No. 670, a rule implementing the anti-manipulation provision of EPAct 2005. The rule makes it unlawful for any entity, directly or indirectly, in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC, or the purchase or sale of transportation services subject to the jurisdiction of FERC, (1) to use or employ any device, scheme or artifice to defraud; (2) to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (3) to engage in any act, practice, or course of business that operates as a fraud or deceit upon any person. The anti-manipulation rules do not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but do apply to activities of gas pipelines and storage companies that provide interstate services, such as Section 311 service, as well as otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction, which now includes the annual reporting requirements under Order 704. The anti-manipulation rules and enhanced civil penalty authority reflect an expansion of FERC's NGA enforcement authority. Should we fail to comply with all applicable FERC administered statutes, rules, regulations, and orders, we could be subject to substantial penalties and fines.

FTC Anti-Manipulation Rule. Effective November 4, 2009, pursuant to the Energy Independence and Security Act of 2007, the FTC issued a rule prohibiting market manipulation in the petroleum industry. The FTC rule prohibits any person, directly or indirectly, in connection with the purchase or sale of crude oil, gasoline or petroleum distillates at wholesale from: (a) knowingly engaging in any act, practice or course of business, including the making of any untrue statement of material fact, that operates or would operate as a fraud or deceit upon any person; or (b) intentionally failing to state a material fact that under the circumstances renders a statement made by such person misleading, provided that such omission distorts or is likely to distort market conditions for any such product. A violation of this rule may result in civil penalties of up to $1 million per day per violation, in addition to any applicable penalty under the Federal Trade Commission Act.

Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, FERC and the courts. We cannot predict the ultimate impact of these or the above regulatory changes to our natural gas operations. We do not believe that we would be affected by any such action materially differently than similarly situated competitors.

Certain Technical Terms

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used herein in reference to oil or other liquid hydrocarbons.

BBtu. Billion Btus.

Bcf. Billion cubic feet.

Bcfe. Billion cubic feet of natural gas equivalent, determined using the ratio of one Bbl of oil or condensate to six Mcf of natural gas.

BOE. Barrel of oil equivalent.

Btu. British thermal unit, which is the heat required to raise the temperature of a one pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

Developed Acreage. The number of acres which are allocated or assignable to producing wells or wells capable of production.

Development Location. A location on which a development well can be drilled.

Development Well. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

Drilling Unit. An area specified by governmental regulations or orders or by voluntary agreement for the drilling of a well to a specified formation or formations which may combine several smaller tracts or subdivides a large tract, and within which there is usually some right to share in production or expense by agreement or by operation of law.

Dry Hole. A well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

Estimated Future Net Revenues. Estimated future gross revenue to be generated from the production of proved reserves, net of estimated production, future development costs, and future abandonment costs, using an average first-day of the month price for the last 12 months under the new SEC rules and costs in effect as of the date of the report or estimate, without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expense or to depreciation, depletion and amortization.

Exploratory Well. A well drilled to find and produce oil or gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir, or to extend a known reservoir.

Finding and Development Costs. The total costs incurred for exploration and development activities (excluding exploratory drilling in progress and drilling inventories), divided by total proved reserve additions. To the extent any portion of the proved reserve additions consist of proved undeveloped reserves, additional costs would have to be incurred in order for such proved undeveloped reserves to be produced. This measure may differ from the measure used by other oil and natural gas companies.

Gross Acre. An acre in which a working interest is owned.

Gross Well. A well in which a working interest is owned.

H/B Hz. Haynesville/Bossier Shale horizontal well.

Hz. Horizontal.

Infill Drilling. Drilling for the development and production of proved undeveloped reserves that lie within an area bounded by producing wells.

Injection Well. A well which is used to place liquids or gases into the producing zone during secondary/tertiary recovery operations to assist in maintaining reservoir pressure and enhancing recoveries from the field or productive horizons.

Lease Operating Expense. All direct costs associated with and necessary to operate a producing property.

MBbls. Thousand barrels.

MBtu. Thousand Btus.

Mcf. Thousand cubic feet.

Mcfe. Thousand cubic feet of natural gas equivalent, determined using the ratio of one Bbl of oil or condensate to six Mcf of natural gas.

Mcfpd. Thousand cubic feet per day.

MMBbls. Million barrels.

MMBtu. Million Btus.

MMcf. Million cubic feet.

MMcfe. Million cubic feet of natural gas equivalent, determined using the ratio of one Bbl of oil or condensate to six Mcf of natural gas.

Natural Gas Liquids. Liquid hydrocarbons which have been extracted from natural gas (e.g., ethane, propane, butane and natural gasoline).

Net Acres or Net Wells. The sum of the fractional working interests owned in gross acres or gross wells.

NYMEX. New York Mercantile Exchange.

Operator. The individual or company responsible for the exploration, exploitation and production of an oil or natural gas well or lease, usually pursuant to the terms of a joint operating agreement among the various parties owning the working interest in the well.

Present Value. When used with respect to oil and natural gas reserves, present value means the Estimated Future Net Revenues discounted using an annual discount rate of 10%.

Productive Well. A well that is producing oil or gas or that is capable of production.

Proved Developed Reserves. Proved reserves are expected to be recovered through existing wells with existing equipment and operating methods. Additional oil 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 as proved developed reserves only after testing by pilot project or after the operation of an installed program as confirmed through production response that increased recovery will be achieved.

Proved Reserves. Proved natural gas and oil reserves are those quantities of natural gas and oil, which, by analysis of geoscience 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. The area of a 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 natural gas or oil on the basis of available geoscience and engineering data. In the absence of information 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. 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. 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. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price 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 upon future conditions.

Proved Undeveloped Reserves. Proved 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 recompletion. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time. Estimates for proved undeveloped reserves are not attributed 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 projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

Recompletion. The completion for production of an existing wellbore in another formation from that in which the well has previously been completed.

Royalty. An interest in an oil and natural gas lease that gives the owner of the interest the right to receive a portion of the production from the leased acreage (or of the proceeds of the sale), but generally does not require the owners to pay any portion of the costs of drilling or operating wells on the leased acreage. Royalties may be either landowner's royalties, which are reserved by the owner of a leased acreage at the time the lease is granted, or overriding royalties, which are usually reserved by an owner of the leasehold in connection with the transfer to a subsequent owner.

Secondary Recovery. An artificial method or process used to restore or increase production from a reservoir after the primary production by the natural producing mechanism and reservoir pressure has experienced partial depletion. Gas injection and water flooding are examples of this technique.

Undeveloped Acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves.

Waterflood. A secondary recovery operation in which water is injected into the producing formation in order to maintain reservoir pressure and force oil toward and into the producing wells.

Working Interest. An interest in an oil and natural gas lease that gives the owner of the interest the right to drill for and produce oil and natural gas on the leased acreage and requires the owner to pay a share of the costs of drilling and production operations.

Workover. To carry out remedial operations on a productive well with the intention of restoring or increasing production.

Availability of Information

Our SEC filings are available to the public over the Internet at the SEC's web site at www.sec.gov. You may also read and copy any document we file at the SEC's public reference room located at 100 F Street, N.E., Washington D.C. 20549. Please call the SEC at 1-800-SEC-0330 for further information on the public reference room and copy charges. Also, using our website, http://www.gmxresources.com, you can access electronic copies of documents we file with the SEC, including our annual reports on Form 10-K, quarterly reports on Form 10-Q, and current reports on Form 8-K and any amendments to those reports. Information on our website is not incorporated by reference in this report. You may also request a copy of those filings, excluding exhibits, at no cost by writing Alan Van Horn at our principal executive office, which is located at 9400 North Broadway, Suite 600, Oklahoma City, OK 73114, or by telephone or email at (405) 600-0711 or avanhorn@gmxresources.com, respectively.

Item 1A. Risk Factors.

Risks Related to GMX

The following are some of the important factors that could affect our financial performance or could cause actual results to differ materially from estimates contained in our forward-looking statements. We may encounter risks in addition to those described below. Additional risks and uncertainties not currently known to us, or that we currently deem to be immaterial, may also impair or adversely affect our business, results of operation, financial condition and prospects.

Our future performance depends upon our ability to obtain capital to find or acquire additional oil and natural gas reserves that are economically recoverable.

Unless we successfully replace the reserves that we produce, our reserves will decline, eventually resulting in a decrease in oil and natural gas production and lower revenues and cash flows from operations. The business of exploring for, developing and acquiring reserves requires substantial capital expenditures. Our ability to make the necessary capital investment to maintain or expand our oil and natural gas reserves is limited by our relatively small size. In addition, approximately 43% of our total estimated proved reserves at December 31, 2011 were undeveloped. By their nature, estimates of undeveloped reserves are less certain. Recovery of such reserves will require significant capital expenditures and successful drilling operations. Further, our drilling activities are subject to numerous risks, including the risk that no commercially productive oil or natural gas reserves will be encountered. Thus, our future natural gas and oil reserves and production and, therefore, our cash flow and income are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves.

We have historically relied upon draws on our secured revolving credit facility to help fund our capital expenditures, which agreement contained borrowing base limitations linked to our oil and gas reserves. Although we terminated our secured revolving credit facility in connection with the issuance of our Senior Secured Notes issued in December 2011 and our Senior Secured Notes will generally prohibit our ability to enter into a new secured revolving credit facility, our ability to borrow any permitted future secured or unsecured indebtedness will also likely depend on the value that lenders place on our oil and natural gas properties, which in turn depends on prevailing commodity prices. We expect that lower commodity prices would constrain our ability to incur, or affect the pricing of, additional debt or equity financings, which could adversely affect our ability to operate our business, including drilling and proving up additional recoverable reserves.

Our substantial level of indebtedness could adversely affect our financial condition and prevent us from fulfilling our obligations under our secured and unsecured notes and our other indebtedness.

As of December 31, 2011, on a consolidated basis we had total indebtedness of $426.8 million, including $283.5 million of senior secured indebtedness, consisting of our Senior Secured Notes, and no availability under our prior secured revolving credit facility, which was terminated in December 2011.

Our outstanding indebtedness could have important consequences to you, including the following:

- our high level of indebtedness could make it more difficult for us to satisfy our obligations with respect to the such indebtedness, including any repurchase obligations that may arise thereunder;
- our ability to obtain additional financing for working capital, capital expenditures, debt service requirements, restructuring, acquisitions or general corporate purposes may be impaired, which could be exacerbated by further volatility in the credit markets;
- we must use a substantial portion of our cash flow from operations to pay interest on our indebtedness and outstanding preferred stock, which will reduce the funds available to us for operations and other purposes;
- our high level of indebtedness could place us at a competitive disadvantage compared to our competitors that may have proportionately less debt;
- our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate may be limited; and
- our high level of indebtedness makes us more vulnerable to economic downturns and adverse developments in our business.

Any of the foregoing could have a material adverse effect on our business, financial condition, results of operations prospects and ability to satisfy our obligations under the secured notes.

The indenture governing our Senior Secured Notes contains certain covenants that may inhibit our ability to make certain investments (including the repayment or redemption of other indebtedness and our preferred stock), incur additional indebtedness and engage in certain other transactions, which could adversely affect our ability to meet our future goals.

The indenture governing our Senior Secured Notes contains certain covenants that, among other things, restrict our ability to:

- make investments, loans and advances, pay dividends on our common stock, and other restricted payments;
- incur additional indebtedness;
- grant liens, other than certain permitted liens; and
- merge, consolidate and sell our business or properties.

These restrictive covenants may restrict our ability to expend or pursue our business strategies. Our ability to comply with these and other provisions of the indenture governing our Senior Secured Notes may be impacted by lower commodity prices, changes in economic or business conditions, results of operations or events beyond our control. If we were unable to repay borrowings or interest under our secured or unsecured notes, the trustee under the indenture governing the Senior Secured Notes could proceed against the collateral securing the Senior Secured Notes. If we fail to pay interest or principal when due under our 11.375% Senior Notes due 2019, such obligations and the obligations under our Senior Secured Notes would also be accelerated, and we may not have sufficient liquidity to repay our indebtedness in full.

The undeveloped acreage acquired during 2011, in addition to our existing large inventory of undeveloped acreage and large percentage of undeveloped proved reserves, creates additional economic risk. Such assets may not produce oil or natural gas as projected.

Our success is dependent upon our ability to develop significant amounts undeveloped acreage and undeveloped reserves. As of December 31, 2011, approximately 43% of our total proved reserves were undeveloped. Our 2011 acquisitions of Bakken and Niobrara properties consist entirely of undeveloped acreage and do not have any undeveloped proved reserves. To the extent the drilling results on our current properties or on the properties acquired are not as successful as we anticipate, natural gas and oil prices decline, or sufficient funds are not available to drill these locations and reserves, we may not capture the expected or projected value of these properties. In addition, delays in the development of our reserves or increases in costs to drill and develop such reserves will reduce the PV-10 value of our estimated proved undeveloped reserves and future net revenues estimated for such reserves and may result in some projects becoming uneconomic, including those on the properties acquired during 2011.

Our current program in emerging shale plays uses some relatively new horizontal drilling and completion techniques, and results for our planned exploratory drilling in these plays will be subject to drilling techniques and completion risks. As a result, our drilling results may not meet our expectations for reserves or production, and we may incur material write downs and the value of our undeveloped acreage could decline in the future.

Operations in the Bakken and Niobrara formations involve utilizing relatively new drilling and completion techniques as developed by our service providers or us in order to maximize cumulative recoveries and to generate the highest possible returns. Risks that we face include, but are not limited to, landing our well bore in the desired drilling zone, staying in the desired drilling zone while drilling horizontally through the formation, running our casing the entire length of the well bore and being able to run tools and other equipment consistently through the horizontal well bore. Risks that we face while completing our wells include, but are not limited to, being able to fracture stimulate the planned number of stages, being able to run tools the entire length of the well bore during completion operations and successfully cleaning out the well bore after completion of the final fracture stimulation stage.

We currently have limited experience, and our service providers have limited experience, utilizing the latest drilling and completion techniques being used specifically in the Bakken formations. The success of these drilling and completion techniques can only be evaluated over time as more wells are drilled and production profiles are established over a sufficiently long time period. If our drilling results in these formations are less than anticipated, or we are unable to execute our drilling program because of capital constraints, lease expirations, access to gathering systems and limited takeaway capacity or otherwise, and/or natural gas or oil prices decline, the return on our investment in these areas may not be as attractive as we anticipate and we could incur material write downs of unevaluated properties and the value of our undeveloped acreage could decline in the future.

Significant capital expenditures are required to replace our reserves, and our cash flows from operations may not be sufficient for future capital expenditures.

Our development, exploration, and acquisition activities require substantial capital expenditures. Historically, we have funded our capital expenditures through a combination of cash flows from operations and debt and equity financing. Future cash flows are subject to a number of variables, such as the level of production from existing wells, prices of oil and natural gas, and our success in developing and producing new reserves. If our cash flow from operations is not sufficient to fund our capital expenditure budget, we may not be able to access other methods of financing on commercially reasonable terms to meet these requirements. If revenue were to decrease as a result of lower oil and natural gas prices or decreased production, and our access to capital were limited, we would have a reduced ability to replace our reserves which may have an adverse effect on our results of operations and financial condition. In addition to cash flow, we anticipate funding future capital expenditures with equity transactions, as well as, potential asset sales and joint venture opportunities.

The loss of our Chief Executive Officer or other key personnel could adversely affect us.

We depend to a large extent on the efforts and continued employment of Ken L. Kenworthy, Jr., our Chief Executive Officer. The loss of his services could adversely affect our business. In addition, if Mr. Kenworthy resigns or we terminate him as our Chief Executive Officer, we would be required to offer to repurchase all of our outstanding Series B Preferred Stock. The indenture governing our Senior Secured Notes will restrict our ability to repurchase our outstanding Series B Preferred Stock, and we may be required to issue other preferred or common stock in order to raise cash for such required repurchases. Any such issuances required for such financing could have a dilutive effect on holders of our common stock. Our failure to be able to comply with this obligation to repurchase our Series B Preferred Stock could have an adverse effect on such preferred stock or on our common stock.

We are subject to financing risks.

Our future success depends in part on our ability to access capital markets and obtain financing on reasonable terms. Our ability to access financial markets and obtain financing on commercially reasonable terms in the future is dependent on a number of factors, many of which we cannot control, including changes in:

- our credit ratings;
- interest rates;
- the structured and commercial financial markets;
- market perceptions of us or the oil and natural gas exploration and production industry; and
- tax burden due to new tax laws.

Our exposure to producing properties and operations in the Bakken formation in Montana and North Dakota region makes us vulnerable to risks associated with operating in a concentrated major geographic area.

During 2011, we acquired significant positions in undeveloped lease acreage in the Niobrara formation of the DJ Basin in Wyoming and the Bakken/Sanish-Three Forks formation in Montana and North Dakota. As a result, we are exposed to the risks associated with operating in this geographic area, including, but not limited to, delays or interruptions of production from these wells caused by transportation capacity constraints, curtailment of production, availability of equipment, facilities, personnel or services, significant governmental regulation, natural disasters, adverse weather conditions, plant closures for scheduled maintenance or interruption of transportation of oil or natural gas produced from the wells in this area. In addition, the effect of fluctuations on supply and demand may become more pronounced within specific geographic oil and gas producing areas, which may cause these conditions to occur with greater frequency or magnify the effect of these conditions. Such delays or interruptions could have a material adverse effect on our financial condition and results of operations.

A majority of our production, revenue and cash flow from operating activities has been derived historically from assets that are concentrated in a single geographic area.

A substantial majority of our estimated proved reserves at December 31, 2011 were associated with our East Texas wells. Accordingly, if the level of production from these properties substantially declines, it could have a material adverse effect on our overall production level and our revenue. Approximately 29% of our estimated proved reserves relate to wells in the Cotton Valley Sands and shallower layers as of December 31, 2011. During 2011, we allocated only a limited portion of our capital expenditures, and we currently plan to allocate only a de minimis portion of our 2012 capital expenditure budget, to our East Texas wells. This may affect the production, revenue and cash flow we derive from further development of the these natural gas-focused reserves, including the Cotton Valley Sands formation and Haynesville/Bossier Share formation layers.

Delays in development or production curtailment affecting our material properties may adversely affect our financial position and results of operations.

The size of our operations and our capital expenditure budget limits the number of wells that we can develop in any given year. Complications in the development of any single material well may result in a material adverse effect on our financial condition and results of operations. If we were to experience operational problems resulting in the curtailment of production in a material number of our wells, our total production levels would be adversely affected, which would have a material adverse effect on our financial condition and results of operations.

Increased drilling in our current leased or owned properties may cause pipeline capacity problems that may limit our ability to sell natural gas and oil.

If drilling in the Haynesville/Bossier Shale were to accelerate, the amount of gas being produced in and around our core area from these new wells, as well as other existing wells, may exceed the capacity of the various gathering and intrastate or interstate transportation pipelines currently available. If this occurs, it will be necessary for new pipelines and gathering systems to be built. In addition, capital constraints could limit our ability to build intrastate gathering systems necessary to transport our gas to interstate pipelines. In such event, we might have to shut in our wells awaiting a pipeline connection or capacity and/or sell natural gas production at significantly lower prices than we currently project, which would adversely affect our results of operations.

In addition, there are crude oil and natural gas pricing and take-away risks in the Bakken and Niobrara basins. In the Bakken, producers sell their crude oil to marketers who take delivery and title at the producer's tank battery facilities, and transport the crude to markets for resale. Crude oil is trucked from the producer's tank batteries to both pipelines and rail facilities whose available capacity can be curtailed in the winter season due to inclement weather. There is currently 650,000 Bbls of take-away capacity which is comprised of approximately 400,000 Bbls of pipeline capacity and 250,000 Bbls of rail capacity. Third parties have announced expansion projects totaling approximately 1,134,000 Bbls of new capacity projects that may become available over the next 18 months. The average difference between the WTI crude oil price and the North Dakota Crude Oil First Purchase Price for the year ended December 31, 2011 was $5.79 per Bbl.

Natural gas produced in the Bakken has a high Btu content that requires gas processing to remove the natural gas liquids before it can be redelivered into transmission pipelines; this is done by either producers or third party processors, who currently operate a total of 16 plants. There is over 4.0 Bcf per day of natural gas take-away capacity on transmission pipelines; the capacity is currently fully subscribed, though the entire capacity is not currently being utilized. There have been announced additional capacity projects totaling over 1.0 Bcf per day that are scheduled to go in service in 2012. The natural gas prices realized by producers in the Bakken are a function of the NYMEX price, less transportation costs, plus the upgrade received from the proceeds related to the natural gas liquids that are extracted and sold separately.

In the Niobrara, producers sell their crude oil to marketers who take delivery and title at the producer's tank battery facilities, and transport the crude to markets for resale. Crude oil is trucked from the producer's tank batteries to pipelines whose available capacity can be curtailed in the winter season due to inclement weather. There is currently 200,000 Bbls of pipeline take-away capacity. The average difference between the WTI crude oil price and the Wyoming Crude Oil First Purchase Price for the year ended December 31, 2011 was $11.47 per Bbl.

Natural gas produced in the Niobrara has a high Btu content that requires gas processing to remove the natural gas liquids before it can be redelivered into transmission pipelines; this is done by either producers or third party processors. There is over 8.0 Bcf per day of natural gas take-away capacity on transmission pipelines; the capacity is currently fully subscribed, though approximately 40% of the entire capacity is not currently being utilized. There have been announced additional capacity projects totaling over 2.0 Bcf per day that are scheduled to go in service in 2012. Though transmission capacity exists, extensive gas gathering infrastructure does not currently exist in the counties in which we will operate, and will need to be built by producers or pipeline companies. The natural gas prices realized by producers in the Niobrara are a function of the NYMEX price, less transportation costs, plus the upgrade received from the proceeds related to the natural gas liquids that are extracted and sold separately.

Such fluctuations and discounts could have a material adverse effect on our financial condition and results of operations.

Certain of our Cotton Valley Sands wells produce oil and natural gas at a relatively slow rate.

We expect that our existing Cotton Valley Sands wells and certain other wells that we plan to drill on our existing properties will produce the oil and natural gas constituting the reserves associated with those wells over a period of up to 50 years. Because of the relatively slow rates of production of our wells, our reserves will be affected by long term changes in oil or natural gas prices or both, and we will be limited in our ability to anticipate any price declines by increasing rates of production. We may hedge our reserve position by selling oil and natural gas forward for limited periods of time, but we do not anticipate that, in declining markets, the price of any such forward sales will be attractive.

The recent adoption of The Dodd-Frank Wall Street Reform and Consumer Protection Act, or the "Dodd-Frank Act," could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price and other risks associated with our business.

We use derivative instruments to manage our commodity price risk. The United States Congress recently adopted comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. The Dodd-Frank Act requires the Commodity Futures Trading Commission (the "CFTC") and the SEC to promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment. The CFTC has also proposed regulations to set position limits for certain futures and option contracts in the major energy markets, although it is not possible at this time to predict whether or when the CFTC will adopt those rules or include comparable provisions in its rulemaking under the new legislation. 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 new legislation and any new regulations could significantly increase the cost of derivative contracts (including 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. 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 us, our financial condition and our results of operations.

The concentration of accounts for our oil and natural gas sales, joint interest billings or hedging with third parties could expose us to credit risk.

Substantially all of our accounts receivable result from oil and natural gas sales or joint interest billings to third parties in the energy industry. The concentration of customers and joint interest owners may impact our overall credit risk in that these entities may be similarly affected by changes in economic and other conditions. Recently, we have not experienced any material credit losses on our receivables. Future concentration of sales of oil and natural gas commensurate with decreases in commodity prices could result in adverse effects.

In addition, our oil and natural gas swaps or other hedging contracts expose us to credit risk in the event of non-performance by counterparties. We believe that the guarantee of a fixed price for the volume of oil and natural gas hedged reduces volatility in our reported results of operations, financial position and cash flows from period to period and lowers our overall business risk. However, as also discussed along with other risks specific to hedging activities, we may be exposed to greater credit risk in the future.

Failure by us to achieve and maintain effective internal control over financial reporting in accordance with the rules of the SEC could harm our business and operating results and/or result in a loss of investor confidence in our financial reports, which could have a material adverse effect on our business.

We have evaluated our internal controls systems to allow management to report on, and our independent auditors to audit, our internal controls over financial reporting. We have performed the system and process evaluation and testing required to comply with the management certification and auditor attestation requirements of Section 404 of the Sarbanes-Oxley Act of 2002. As a public company, we are required to report, among other things, control deficiencies that constitute a "material weakness" or changes in internal controls that, or that are reasonably likely to, materially affect internal controls over financial reporting. In March 2010, we identified control deficiencies under applicable SEC and Public Company Accounting Oversight Board rules and regulations that resulted in a "material weakness" and from management's improper application of GAAP resulting in corrections to our previously reported December 31, 2008 consolidated financial statements and the financial statements for the first three quarters of 2009. Management failed to timely detect and correct errors relating to the improper application of GAAP in determining our full cost pool impairment charges, other impairment charges, and related deferred income taxes. Management also failed to timely detect and correct errors as a result of improperly including dilutive securities in our computation of diluted loss per share. We reported this "material weakness" in Part II. Item 9A—Controls and Procedures of our 2009 Form 10-K. A "material weakness" is a deficiency, or combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the Company's annual or interim consolidated financial statements will not be prevented or detected on a timely basis. The report by us of a material weakness may cause investors to lose confidence in our consolidated financial statements, and our stock price may be adversely affected as a result. As a consequence of the material weakness described above, our management implemented a plan to add and reassign certain duties within the financial reporting department to ensure executive financial management has sufficient resources to properly research new and existing accounting guidance on a regular basis. As of December 31, 2011 and 2010, qualified personnel had been added and duties have been reassigned to remediate these internal control deficiencies. If we fail to achieve and maintain effective internal control over financial reporting, our consolidated financial statements may be inaccurate, we may face restricted access to the capital markets and the price of our securities may be adversely affected.

The continued instability in the global financial system may have impacts on our liquidity and financial condition that we currently cannot predict.

The continued instability in the global financial system may have a material impact on our liquidity and our financial condition, and we may ultimately face major challenges if conditions in the financial markets do not continue to improve from their lows in early 2009. Our ability to access the capital markets or borrow money may be restricted or made more expensive at a time when we would like, or need, to raise capital, which could have an adverse impact on our flexibility to react to changing economic and business conditions and on our ability to fund our operations and capital expenditures in the future. The economic situation could have an impact on our lenders or customers, causing them to fail to meet their obligations to us, and on the liquidity of our operating partners, resulting in delays in operations or their failure to make required payments. Also, market conditions could have an impact on our natural gas and oil derivatives transactions if our counterparties are unable to perform their obligations or seek bankruptcy protection. Additionally, the current economic situation could lead to further reductions in the demand for natural gas and oil, or further reductions in the prices of natural gas and oil, or both, which could have a negative impact on our financial position, results of operations and cash flows. While the ultimate outcome and impact of the current financial situation cannot be predicted, it may have a material adverse effect on our future liquidity, results of operations and financial condition.

A portion of total proved reserves as of December 31, 2011 are undeveloped, and those reserves may not ultimately be developed.

As of December 31, 2011, approximately 43% of our estimated proved reserves were undeveloped. Recovery of undeveloped reserves requires significant capital expenditures and successful drilling. The reserve data assumes that we can and will make these expenditures and conduct these operations successfully. While we are reasonably certain of our ability to make these expenditures and to conduct these operations under existing economic conditions, these assumptions may not prove correct and we may ultimately determine the development of all, or any portion of, such proved, but undeveloped, reserves is not economically feasible.

If we are not able to replace reserves, we may not be able to sustain production.

Our future success depends largely upon our ability to find, develop or acquire additional oil and natural gas reserves that are economically recoverable. Unless we replace the reserves we produce through successful development, exploration or acquisition activities, our proved reserves and production will decline over time. In addition, approximately 43% of our total estimated proved reserves (by volume) at December 31, 2011 were undeveloped. By their nature, estimates of undeveloped reserves are less certain.

Recovery of such reserves will require significant capital expenditures, successful drilling. Our December 31, 2011 reserve estimates reflect that our production rate on current proved developed producing reserve properties will decline at annual rates of approximately 32%, 26%, and 7% for the next three years. The decline rates include the volumes related to the VPP for the purposes of these calculations. Thus, our future oil and natural gas reserves and production and, therefore, our financial condition, results of operations and cash flows are highly dependent on our success in efficiently developing our current reserves and economically discovering or acquiring additional recoverable reserves.

Prior to 2011, we had no experience drilling wells in the Bakken or Niobrara shale formations and less information regarding reserves and decline rates in the Bakken and Niobrara formations than in other areas of our operations.

Prior to 2011, we had no exploration or development experience in the Bakken or Niobrara shale formations. Other operators in the these formations and the related Williston and DJ basins have significantly more experience in the drilling of Bakken and Niobrara wells, including the drilling of horizontal wells. As a result, we have less information with respect to the ultimate recoverable reserves and the production decline rate in the Bakken and Niobrara formations than we have in other areas in which we operate.

We may not complete additional acquisitions in areas with exposure to oil, condensate and natural gas liquids.

If we are unable to complete additional Niobrara or Bakken shale acquisitions, this may detract from our efforts to realize our growth strategy in crude oil and liquids-rich plays. Additionally, we may be unable to find or consummate other opportunities in these areas or in other areas with similar exposure to oil, condensate and natural gas liquids on similar terms or at all.

Development and exploration drilling may not result in commercially productive reserves.

Drilling activities are subject to many risks, including the risk that commercially productive reservoirs will not be encountered. We cannot provide assurance that new wells drilled by us will be productive or that we will recover all or any portion of our investment in such wells. The seismic data and other technologies we use do not allow us to know conclusively prior to drilling a well that oil or natural gas is present or may be economically recovered and/or produced. Drilling for oil and natural gas often involves unprofitable efforts, not only from dry wells but also from wells that are productive but do not produce sufficient net reserves to return a profit at then-realized prices after deducting drilling, operating and other costs. The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a project. Further, our drilling operations may be curtailed, delayed or cancelled as a result of numerous factors, including:

- unexpected drilling conditions;
- title problems;
- pressure or lost circulation in formations;
- equipment failures or accidents;
- adverse weather conditions;
- compliance with environmental and other governmental requirements; and
- increases in the cost of, or shortages or delays in the availability of, drilling rigs, equipment and services.

If, for any reason, we are unable to economically recover reserves through our exploration and drilling activities, our results of operations, cash flows, growth and reserve replenishment may be materially affected.

Properties that we acquire may not produce as projected and we may be unable to accurately predict reserve potential, identify liabilities associated with the properties or obtain protection from sellers against such liabilities.

Acquisitions of producing and undeveloped properties have been an important part of our historical growth. We expect acquisitions will also contribute to our future growth. Successful acquisitions require an assessment of a number of factors, including recoverable reserves, exploration or development potential, future oil and natural gas prices, operating costs, and potential environmental and other liabilities. We perform an engineering, geological and geophysical review of the acquired properties, the scope of which review we believe is generally consistent with industry practices. However, such assessments are inexact and their accuracy is inherently uncertain for a number of reasons. For instance, in connection with our assessments, such a review may not permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities or other liabilities associated therewith. We do not physically inspect every well. Even when we inspect a well, we do not always discover structural, subsurface and environmental problems that may currently exist or arise in the future. Our review prior to signing a definitive purchase agreement may be even more limited. Often we are not entitled to contractual indemnification for pre-closing liabilities, including environmental liabilities associated with acquired properties.

Normally, we acquire interests in properties on an "as is" basis with limited remedies for breaches of representations and warranties. As a result, significant unknown liabilities, including environmental liabilities, may exist, and we may experience losses due to title defects in acquisitions for which we have limited or no contractual remedies or insurance coverage. In addition, we may acquire oil and natural gas properties that contain economically recoverable reserves that are less than predicted. Thus, liabilities and uneconomically feasible oil and natural gas recoveries related to our acquisitions of producing and undeveloped properties may have a material adverse effect on our results of operations and reserve growth.

If the third parties we rely on for gathering and distributing our oil and natural gas are unable to meet our needs for such services and facilities, our future exploration and production activities could be adversely affected.

The marketability of our production depends upon the proximity of our reserves to, and the capacity of, third-party facilities and third-party services, including oil and natural gas gathering systems, pipelines, trucking or terminal facilities, and refineries or processing facilities. Such third parties are subject to federal and state regulation of the production and transportation of oil and natural gas. If such third parties are unable to comply with such regulations and we are unable to replace such service and facilities providers, we may be required to shut-in producing wells or delay or discontinue development plans for our properties. A shut-in, delay or discontinuance could adversely affect our financial condition.

Our undeveloped acreage must be drilled before lease expiration, generally within three to five years, in order to hold the acreage by production. In the highly competitive market for acreage, failure to drill sufficient wells to hold acreage will result in a substantial lease renewal cost, or if renewal is not feasible, loss of our lease and prospective drilling opportunities.

Unless production is established within the spacing units covering the undeveloped acres on which some of the locations are identified, the leases for such acreage could expire. As of December 31, 2011, we had leases representing 4,782 net acres (3,491 Bakken and 1,291 East Texas) expiring in 2012, 20,337 net acres (5,882 Bakken, 11,645 Niobrara and 2,810 East Texas) expiring in 2013 and 20,060 net acres (6,094 Bakken, 8,738 Niobrara and 5,228 East Texas) expiring in 2014. In addition, a significant portion of the acreage that we acquired in 2011 in the Bakken and Niobrara formations described under "Item 1. Business" will expire in the next three to five years unless extended as allowed under the terms of the individual lease agreements or held by production by producing wells. The cost to renew such leases may increase significantly, and we may not be able to renew such leases on commercially reasonable terms or at all. Based on anticipated drilling plans and our intent to extend expiring leases, under the existing terms of the lease agreements, a significant portion of the acreage will not expire as indicated. As a result, our anticipated realized expirations will be 1,710 net acres (1,125 Bakken, 585 East Texas) in 2012, 3,057 net acres (1,291 Bakken, 1,614 East Texas and 152 Niobrara) in 2013 and 6,081 net acres (1,356 Bakken, 3,488 East Texas and 1,237 Niobrara) in 2014. In addition, on certain portions of our acreage, third-party leases become immediately effective if our leases expire. As such, our actual drilling activities may differ materially from our current expectations, which could adversely affect our business.

We may incur losses as a result of title defects in the properties in which we invest.

As is customary in the industry, we do not generally incur the expense of retaining lawyers to examine title to the mineral interest when acquiring oil and gas leases or interests. Rather, we rely on the judgment of oil and gas lease brokers or landmen who perform the fieldwork in examining records in the appropriate governmental office before attempting to acquire a lease in a specific mineral interest. Prior to drilling an oil and gas well, it is the customary practice in our industry for the operator of the well to obtain a preliminary title review to ensure there are no obvious defects in title to the well. Frequently, as a result of such examinations, certain curative work must be done to correct defects in the marketability of title, and such curative work entails expense. Our failure to cure any title defects may adversely impact our ability in the future to increase production and reserves. There is no assurance that we will not suffer a monetary loss from title defects or title failure. Additionally, undeveloped acreage has greater risk of title defects than developed acreage. If there are any title defects or defects in assignment of leasehold rights in properties in which we hold an interest, we will suffer a financial loss.

We may have difficulty managing any future growth and the related demands on our resources.

We have experienced growth in the past through the expansion of our drilling program and through acquisitions. Any future growth may place a significant strain on our financial, technical, operational and administrative resources. We may experience difficulties in finding and retaining additional qualified personnel. In an effort to meet the demands of our planned activities in 2012 and thereafter, we may be required to supplement our staff with contract and consultant personnel until we are able to hire new employees. As a result, we may be unable to fully execute our growth plans, including acquiring new properties in our core area and drilling new and existing wells in our core area, all of which could have a material adverse effect on our growth, results of operations and our ability to pay the principal, premium, if any, and interest on our long-term indebtedness.

Our operations in North Dakota, Montana and Wyoming could be adversely affected by abnormally poor weather conditions.

Our operations in North Dakota, Montana and Wyoming are conducted in areas subject to extreme weather conditions and often in difficult terrain. Primarily in the winter and spring, our operations are often curtailed because of cold, snow and wet conditions. Unusually severe weather could further curtail these operations, including drilling of new wells or production from existing wells, and depending on the severity of the weather, could have a material adverse effect on our business, financial condition and results of operations.

Hedging our production may result in losses or limit potential gains.

We enter into hedging arrangements to limit our exposure to the volatility in the prices of oil and natural gas and provide stability to cash flows. As of December 31, 2011, we had entered into no derivative instruments. However, we expect to enter into future derivative instruments that may crude oil and natural gas swaps, collars, three-way collars, and put spreads. Hedging arrangements will expose us to risk of financial loss in some circumstances, including the following:

- production is substantially less than expected;
- the counter-party to the hedging contract defaults on its contractual obligations; and
- there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received.

In addition, these hedging arrangements may limit the benefit we would receive from increases in the prices for oil and natural gas. Additionally, derivatives that are not hedges must be adjusted to fair value through income. If the derivative qualifies and is designated as a cash flow hedge, the effective portion of changes in the fair value of the derivative is recognized in other comprehensive income (loss) until the hedged item is recognized in income. The ineffective portion of a derivative's change in fair value, as measured using the dollar offset method, is immediately recognized in gain (loss) from oil and natural gas hedging activities in the statement of operations.

If it is probable the oil or natural gas sales that are hedged will not occur, hedge accounting must be discontinued, and the gain or loss reported in accumulated other comprehensive income (loss) is immediately reclassified into income. If a derivative that qualified for cash flow hedge accounting ceases to be highly effective, or is liquidated or sold prior to maturity, hedge accounting must be discontinued. The gain or loss associated with the discontinued hedges remains in accumulated other comprehensive income (loss) and is reclassified into income as the hedged transactions occur.

While the primary purpose of our derivative transactions is to protect ourselves against the volatility in oil and natural gas prices, under certain circumstances, or if hedges are deemed ineffective, discontinued, or terminated for any reason, we may incur substantial losses in closing out our positions, which could have a material adverse effect on our financial condition, results of operations, and cash flows. If we choose not to engage in hedging arrangements in the future, we may be more adversely affected by changes in oil and natural gas prices than our competitors, who may or may not engage in hedging arrangements.

Our working capital could be adversely affected if we enter into derivative instruments that require cash collateral.

The use of derivatives may, in some cases, require the posting of cash collateral with counterparties (i.e. margin requirements). Although we currently do not, and do not anticipate that we will in the future, enter into derivative transactions that require an initial deposit of cash collateral, our working capital, and by extension, our growth, could be impacted if we enter into derivative transactions that require cash collateral, and if commodity prices move in a manner adverse to us, we may be required to meet margin calls. Future collateral requirements are uncertain and will depend on arrangements with our counterparties and highly volatile oil and natural gas prices.

Risks Related to the Oil and Natural Gas Industry

Oil and natural gas prices have a material impact on us.

Lower oil and natural gas prices would adversely affect our financial position, financial results, cash flows, access to capital and ability to grow. Our revenues, operating results, profitability, future rate of growth and the carrying value of our oil and natural gas properties depend primarily upon the prices we receive for the oil and natural gas we sell. Prices also affect the amount of cash flow available for capital expenditures and our ability to borrow money or raise additional capital. We may have full-cost ceiling test write-downs in the future if prices fall.

Historically, the markets for oil and natural gas have been volatile, and they are likely to continue to be volatile. Wide fluctuations in oil and natural gas prices may result from relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and other factors that are beyond our control, including:

- worldwide and domestic supplies of oil and natural gas;
- weather conditions;
- commodity processing, gathering, and transportation availability and the availability of refining capacity;
- the level of consumer demand for oil and natural gas;
- the price and availability of alternative fuels;
- the availability of pipeline capacity;
- the price and level of foreign imports of oil and natural gas;
- domestic and foreign governmental regulations and taxes;
- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- financial and commercial market uncertainty;

- political instability or armed conflict in oil and natural gas producing regions; and
- the overall global economic environment.

These factors and the volatility of the energy markets make it extremely difficult to predict future oil and natural gas price movements with any certainty. Declines in oil and natural gas prices would not only reduce revenue, but could reduce the amount of oil and natural gas that we can produce economically and, as a result, could have a material adverse effect on our financial condition, results of operations and reserves. Further, oil and natural gas prices do not necessarily move in tandem. Because approximately 96% of our reserves at December 31, 2011 are natural gas reserves, we are more affected by movements in natural gas prices.

Estimates of proved natural gas and oil reserves and present value of proved reserves are not precise.

There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves and their values, including many factors beyond our control. The reserve data included in this report represent only estimates. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data, the precision of the engineering and geological interpretation, and judgment. As a result, estimates of different engineers often vary. The estimates of reserves, future cash flows and present value are based on various assumptions, including those prescribed by the SEC, and are inherently imprecise. Actual future production, cash flows, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves may vary substantially from our estimates and any significant variations in the interpretations or assumptions underlying our estimates or changes of conditions (*e.g.*, economic growth or regulation) could cause the estimated quantities and net present value of our reserves to differ materially. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and developmental drilling, prevailing oil and natural gas prices and other factors, many of which are beyond our control. Furthermore, the use of a 10% discount factor for reporting purposes may not necessarily represent the most appropriate discount factor, given actual interest rates and risks to which our business or the oil and natural gas industry in general are subject.

Quantities of proved reserves are estimated based on economic conditions, including average oil and natural gas prices calculated at the date of assessment. A reduction in oil and natural gas prices not only would reduce the value of any proved reserves, but also might reduce the amount of oil and natural gas that could be economically produced, thereby reducing the quantity of reserves. Our proved reserves are estimated using assumptions of decline rates based on historic experience. Due to the limited production history we have in our core area, our initial assumptions of decline rates are subject to modification as we gain more experience in operating our wells. Our reserves and future cash flows may be subject to revisions, based upon changes in economic conditions, including oil and natural gas prices, as well as due to production results, results of future development, operating and development costs, and other factors. Downward revisions of our reserves could have an adverse effect on our financial condition and operating results.

At December 31, 2011, approximately 43% of our estimated proved reserves (by volume) were undeveloped. Estimates of proved undeveloped reserves are less certain than estimates of proved developed reserves. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserve data assumes that we will make significant capital expenditures to develop our reserves. Although we have prepared estimates of these oil and natural gas reserves and the costs associated with development of these reserves in accordance with SEC regulations, actual capital expenditures will likely vary from estimated capital expenditures, development may not occur as scheduled and actual results may not be as estimated.

The present value of future net revenues from our proved reserves will not necessarily be the same as the current market value of our estimated oil and natural gas reserves.

You should not assume that the present value of future net revenues from our proved reserves is the current market value of our estimated oil and natural gas reserves. In accordance with current SEC requirements, we have based the estimated discounted future net revenues from our proved reserves on the 12-month unweighted arithmetic average of the first-day-of-the-month price for the preceding twelve months without giving effect to derivative transactions. Actual future net revenues from our oil and natural gas properties will be affected by factors such as:

- actual prices we receive for oil and natural gas;
- actual cost of development and production 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 and amount of actual future net revenues from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net revenues 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. Actual future prices and costs may differ materially from those used in the present value estimates included in this report. If oil prices decline by $15.00 per Bbl, and natural gas prices decline by $0.50 per Mcf, then our PV-10 as of December 31, 2011 would decrease by approximately $63.6 million.

We may incur write-downs of the net book values of our oil and natural gas properties that would adversely affect our equity and earnings.

The full cost method of accounting, which we follow, requires that we periodically compare the net book value of our oil and natural gas properties, including related deferred income taxes, to a calculated "ceiling." The ceiling is the estimated after-tax present value of the future net revenues from proved reserves using a 10% annual discount rate and using constant prices and costs. Any excess of net book value of oil and natural gas properties is written off as an expense and may not be reversed in subsequent periods even though higher oil and natural gas prices may have increased the ceiling in these future periods. The full cost ceiling is evaluated at the end of each quarter using the 12-month average of the first day of the month SEC prices for oil and natural gas as adjusted for our derivative positions deemed "cash flow hedge positions." A write-off constitutes a charge to earnings and reduces equity, but does not impact our cash flows from operating activities. Once incurred, a write-down of oil and natural gas properties is not reversible at a later date. During 2009, we recorded impairment charges of $188.2 million on our oil and natural gas properties due to a ceiling test write-down based on the 12-month average of the first day of the month SEC price for natural gas of $3.87 per MMBtu and a crude oil price of $61.19 per barrel. In connection with our December 31, 2010 financial statements, we recorded an impairment charge of approximately $132.8 million on our oil and natural gas properties due to a ceiling test writedown based on a natural gas price of $4.38 per MMBtu and a crude oil price of $79.43 per barrel. The 2010 impairment charge was a result of our decision to remove approximately 290 net proved undrilled Cotton Valley locations that had proved reserves totaling 219.6 Bcfe at December 31, 2009. Due to the drilling opportunities we have in the Haynesville/Bossier Shale, Bakken and Niobrara Formations, we do not believe we would develop our Cotton Valley Sands proved undeveloped locations within the required five-year timeframe under SEC requirements for including estimated proved reserves. In addition, future development in the Cotton Valley Sands will be on a horizontal basis. During 2011, we recorded an impairment charge of approximately $195.6 million on our oil and natural gas properties due to a ceiling test writedown based on the 12-month average of the first day of the month SEC price for natural gas of $4.12 per MMBtu and a crude oil price of $96.19 per barrel. If commodity prices continue to remain low, we may be subject to additional ceiling test write-downs. Future write-offs may occur that would have a material adverse effect on our net income in the period taken, but would not affect our cash flows. Even though such write-offs do not affect cash flow, they could have an adverse effect on our financial conditions and results of operations.

Operational risks in our business are numerous and could materially impact us.

Our operations involve operational risks and uncertainties associated with drilling for, and production and transportation of, oil and natural gas, all of which can affect our operating results. Our operations may be materially curtailed, delayed or canceled as a result of numerous factors, including:

- the presence of unanticipated pressure or irregularities in formations;
- accidents;
- title problems;
- weather conditions (including any caused by climate change);
- compliance with governmental requirements;
- shortages or delays in the delivery of equipment;
- injury or loss of life;
- severe damage to or destruction of property, natural resources and equipment; and
- pollution or other environmental damage.
- clean-up responsibilities;
- regulatory investigation and penalties;
- other losses resulting in suspension of our operations; and
- injunctions or other proceedings that suspend, limit or prohibit operations.

In accordance with customary industry practice, we maintain insurance against some, but not all, of the risks described above with a general liability and commercial umbrella policy. We do not maintain insurance for damages arising out of exposure to radioactive material. Even in the case of risks against which we are insured, our policies are subject to limitations and exceptions that could cause us to be unprotected against some or all of the risk. The occurrence of an uninsured loss could have a material adverse effect on our financial condition or results of operations

Competition in the oil and natural gas industry is intense, and many of our competitors have greater financial and other resources than we do.

We compete with major integrated oil and natural gas companies and independent oil and natural gas companies in all areas of operation. In particular, we compete for property acquisitions and for the equipment and labor required to operate and develop these properties. Most of our competitors have substantially greater financial and other resources than we have. In addition, larger competitors may be able to absorb the burden of any changes in federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position. These competitors may be able to pay more for exploratory prospects and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or other resources permit. Further, our competitors may have technological advantages and may be able to implement new technologies more rapidly than we can. Our ability to explore for natural gas and oil prospects and to acquire additional properties in the future will depend on our ability to conduct operations, to evaluate and select suitable properties and to consummate transactions in this highly competitive environment.

We may encounter difficulty in obtaining equipment and services.

Higher oil and natural gas prices and increased oil and natural gas drilling activity generally stimulate increased demand and result in increased prices and unavailability for drilling rigs, crews, associated supplies, equipment and services. While we have recently been successful in acquiring or contracting for services, we could experience difficulty obtaining drilling rigs, crews, associated supplies, equipment and services in the future. These shortages could also result in increased costs or delays in timing of anticipated development or cause interests in oil and natural gas leases to lapse. We cannot be certain that we will be able to implement our drilling plans or do so at costs that will be as estimated or acceptable to us.

Governmental regulations could adversely affect our business.

Our business is subject to various federal, state and local laws and regulations on taxation, the exploration for and development, production and marketing of oil and natural gas, and environmental and safety matters. Many laws and regulations require drilling permits and govern the spacing of wells, rates, health of production, prevention of waste and pollution and other matters. These laws and regulations have increased the costs of our operations. In addition, these laws and regulations, and any others that are passed by the jurisdictions where we have production, could limit the total number of wells drilled or the allowable production from successful wells, which could limit our revenues.

Laws and regulations relating to our business frequently change, and future laws and regulations, including changes to existing laws and regulations, could adversely affect our business.

In particular and without limiting the foregoing, various tax proposals under consideration could increase our tax burden. For example, President Obama's budget proposal for the fiscal year 2011, released on February 1, 2010, recommended the elimination of certain key U.S. federal income tax preferences currently available to oil and gas exploration companies. These proposed changes include, but are not limited to, (i) repeal of the percentage of depletion allowance for oil and gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for United Stated production activities, and (iv) the increase of the amortization period from two years to seven years for geophysical costs paid or incurred in connection with the exploration for, or development of, oil or gas within the United States. In addition, proposals under consideration relating to the over-the-counter derivatives market could adversely affect our hedging program related to our natural gas and oil production, since we rely upon the over-the-counter derivatives market for our hedging activities.

Oil and natural gas drilling and production operations can be hazardous and may expose us to environmental or other liabilities that could adversely affect our business.

In the event of a release of oil, natural gas, well fluids, air emissions, or other substances from our operations into the environment, we could incur liability for any and all consequences of such release, including personal injuries, property damage, cleanup costs, damages to natural resources including drinking water resources, and governmental fines or other sanctions. We could potentially discharge these materials into the environment in several ways, including:

- from a well or drilling equipment at a drill site;
- formations with abnormal pressures;
- uncontrollable flows of oil, natural gas, brine or well fluids;

- high pressures and mechanical difficulties related to our drilling operations such as stuck pipes, collapsed casings and separated cables;
- leakage from gathering systems, pipelines, transportation facilities and storage tanks;
- damage to oil and natural gas wells resulting from accidents during normal operations;
- blowouts, fires, cratering and explosions; and
- other environmental hazards and risks.

In addition, because we may acquire interests in or lease properties that have been owned or operated in the past by others, we may be liable for environmental damage, including historical contamination, caused by such former owners or operators. Additional liabilities could also arise from continuing violations of environmental laws and regulations or contamination that we have not yet discovered relating to the acquired properties or any of our other properties. In addition, government regulators could impose additional requirements relating to insurance, bonding or financial assurance, which could increase the costs of our operations.

Although we maintain liability insurance coverage for liabilities from pollution, environmental risks generally are not fully insurable and our insurance may not be adequate to cover any or all resulting losses or liabilities. Moreover, in the future, we may not be able to obtain any such insurance on commercially reasonable terms. The occurrence of, or failure by us to obtain or maintain adequate insurance coverage for, any of the events listed above could have a material adverse effect on our financial condition and results of operations, as well as our growth, exploration, and employee recruitment activities.

To the extent we incur any environmental liabilities, they could adversely affect our results of operations or financial condition.

Environmental liabilities could adversely affect our operating results.

We are subject to numerous environmental laws and regulations that obligate us to prevent or manage pollution, to install and maintain pollution controls and to clean up various sites at, from or to which regulated materials may have been disposed of or released. Under these laws and regulations, we are required to obtain permits from governmental authorities for certain of our operations. We cannot assure you that we have been or will be at all times in complete compliance with all environmental laws, regulations and permits. If we violate or fail to comply with these laws, regulations or permits, we could be fined or otherwise sanctioned by regulators. We could also be held liable for any and all consequences arising out of human exposure to such substances or other environmental damage. In addition, it is not possible for us to estimate reliably the amount and timing of all future expenditures related to environmental matters because of:

- the uncertainties in estimating clean up or compliance costs;
- the potential discovery of additional contamination or contamination more widespread than previously thought;
- the uncertainty in quantifying liability under environmental laws, including those that impose joint and several liability on all potentially responsible parties; and
- the uncertainty of potential future changes to environmental laws and regulations and their enforcement.

Climate change legislation or regulations restricting emissions of "greenhouse gases" could result in increased operating costs and reduced demand for the natural gas and other hydrocarbon products that we transport, store or otherwise handle in connection with our exploration, production, transportation, storage and midstream services.

On December 15, 2009, the EPA published its findings that emissions of carbon dioxide, methane and other greenhouse gases 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. These findings allow the EPA to adopt and implement regulations that would restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act. Accordingly, the EPA recently adopted two sets of regulations addressing greenhouse gas emissions under the Clean Air Act. The first limits emissions of greenhouse gases from motor vehicles beginning with the 2012 model year. EPA has asserted that these final motor vehicle greenhouse gas emission standards trigger Clean Air Act construction and operating permit requirements for stationary sources, commencing when the motor vehicle standards take effect on January 2, 2011. On June 3, 2010, EPA published its final rule to address the permitting of greenhouse gas emissions from stationary sources under the Prevention of Significant Deterioration ("PSD") and Title V permitting programs. This rule "tailors" these permitting programs to apply to certain stationary sources of greenhouse gas emissions in a multi-step process, with the largest sources first subject to permitting. It is widely expected that facilities required to obtain PSD permits for their greenhouse gas emissions will be required to also reduce those emissions according to "best available control technology" standards for greenhouse gases that have yet to be developed. Any regulatory or permitting obligation that limits emissions of greenhouse gases could require us to incur costs to reduce emissions of greenhouse gases associated with our operations and also adversely affect demand for the oil and natural gas that we produce.

In addition, on October 30, 2009, the EPA published a final rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas sources in the United States on an annual basis, beginning in 2011 for emissions occurring after January 1, 2010. On November 9, 2010, the EPA expanded its greenhouse gas reporting rule to include onshore oil and natural gas production, processing, transmission, storage, and distribution facilities. Under these rules, reporting of greenhouse gas emissions from such facilities, including many of our facilities, is required on an annual basis, with reporting beginning in 2012 for emissions occurring in 2011.

In June 2009, the United States House of Representatives passed the "American Clean Energy and Security Act of 2009," or "ACESA," which would establish an economy-wide cap on emissions of greenhouse gases in the United States and would require most sources of greenhouse gas emissions to obtain and hold "allowances" corresponding to their annual emissions of greenhouse gases. Similar legislation may be considered by Congress in the future. Additionally, more than one-third 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. The passage of legislation that limits emissions of greenhouse gases from our equipment and operations could require us to incur costs to reduce the greenhouse gas emissions from our own operations, and it could also adversely affect demand for the oil and natural gas that we produce.

Some have suggested that one consequence of climate change could be increased severity of extreme weather, such as increased hurricanes and floods. If such effects were to occur, our operations could be adversely affected in various ways, including damages to our facilities from powerful winds or rising waters, or increased costs for insurance.

Another possible consequence of climate change is increased volatility in seasonal temperatures. The market for natural gas is generally improved by periods of colder weather and impaired by periods of warmer weather, so any changes in climate could affect the market for the fuels that we produce. Despite the use of the term "global warming" as a shorthand for climate change, some studies indicate that climate change could cause some areas to experience temperatures substantially colder than their historical averages. As a result, it is difficult to predict how the market for our fuels could be affected by increased temperature volatility, although if there is an overall trend of warmer temperatures, it would be expected to have an adverse effect on our business.

We are subject to complex laws and regulations, including environmental and safety regulations, which can adversely affect the cost, manner and feasibility of doing business.

We are subject to certain federal, state, and local laws and regulations relating to the exploration for, and development, production and transportation of, oil and natural gas, as well as environmental and safety matters. We cannot be certain that existing laws or regulations, as currently interpreted or reinterpreted in the future, or future laws or regulations will not harm our business, results of operations and financial condition. We may be required to make large and unanticipated capital expenditures to comply with environmental and other governmental regulations such as:

- land use restrictions;
- drilling bonds and other financial responsibility requirements;
- spacing of wells;
- reporting or other limitations on emissions of greenhouse gases;
- unitization and pooling of properties;
- habitat and endangered species protection, reclamation and remediation, and other environmental protection;
- well stimulation processes;
- CO_2 pipeline requirements;
- produced water disposal;
- safety precautions;
- operational reporting; and
- taxation.

Under these laws and regulations, we could be liable for:

- personal injuries;
- property and natural resource damages;
- oil spills and releases or discharges of hazardous materials;
- well reclamation costs;

- remediation and clean-up costs and other governmental sanctions, such as fines and penalties;
- other environmental damages; and
- reporting or other issues arising from greenhouse gas emissions.

Our operations could be significantly delayed or curtailed and our costs of operations could significantly increase as a result of regulatory requirements or restrictions. We are unable to predict the ultimate cost of compliance with these requirements or their effect on our operations.

Potential legislative and regulatory actions could increase our costs, reduce our revenue and cash flow from oil and natural gas sales, reduce our liquidity or otherwise alter the way we conduct our business.

Pending federal budget proposals released by the White House on February 26, 2009 and February 1, 2010 would potentially increase and accelerate the payment of federal income taxes of independent producers of oil and natural gas. Proposals that would significantly affect us include, but are not limited to, repealing the expensing of intangible drilling costs, repealing the percentage depletion allowance, repealing the manufacturing tax deduction for oil and natural gas companies and increasing the amortization period of geological and geophysical expenses. Additionally, the Senate Bill version of the Oil Industry Tax Break Repeal Act of 2009, introduced on April 23, 2009, and the Senate Bill version of the Energy Fairness for America Act, introduced on May 20, 2009, include many of the proposals outlined in the federal budget proposals. It is unclear, however, whether any such changes will be enacted or how soon such changes could be effective. The passage of any legislation as a result of the budget proposals, either Senate Bill or any other similar change in U.S. federal income tax law could eliminate certain tax deductions that are currently available with respect to oil and natural gas exploration and development, and any such change (i) would make it more costly for us to explore for and develop our oil and natural gas resources and (ii) could negatively affect our financial condition, results of operation and cash flows.

The U.S. Congress is considering measures aimed at increasing the transparency and stability of the over-the-counter ("OTC") derivative markets and preventing excessive speculation. We maintain an active price and basis protection hedging program related to the oil and natural gas we produce.

Additionally, we have used the OTC market exclusively for our oil and natural gas derivative contracts and rely on our hedging activities to manage the risk of low commodity prices and to predict with greater certainty the cash flow from our hedged production. Proposals being considered would impose clearing and standardization requirements for all OTC derivatives and restrict trading positions in the energy futures markets. Such changes would likely materially reduce our hedging opportunities and could negatively affect our revenues and cash flow during periods of low commodity prices.

Federal, state and local legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays in the production of oil and natural gas, including from the developing shale plays. A decline in drilling of new wells and related servicing activities caused by these initiatives could adversely affect our financial position, results of operations and cash flows.

Bills have been introduced in the previous U.S. Congress to regulate hydraulic fracturing operations and related injection of fracturing fluids and propping agents used in fracturing fluids by the oil and natural gas industry under the federal Safe Drinking Water Act ("SDWA") and to require the disclosure of chemicals used in the hydraulic fracturing process under the SDWA, Emergency Planning and Community Right-to-Know Act ("EPCRA"), or other authority. Hydraulic fracturing is an important and commonly used process in the completion of unconventional oil and natural gas wells in shale, coalbed and tight sand formations. We use hydraulic fracturing in many of our wells. Sponsors of such bills have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies, surface waters, and other natural resources, and threaten health and safety. During the last Congress, the former Chairman of the House Energy and Commerce Committee has initiated an investigation of the potential impacts of hydraulic fracturing, which has involved seeking information about fracturing activities and chemicals from certain companies in the oil and gas sector. It is possible that similar measures will be considered in the recently convened 112th Congress. In addition, in March 2010, the EPA announced its intention to conduct a comprehensive research study on the potential adverse impacts that hydraulic fracturing may have on water quality and public health. the initial results are expected in 2012 with the final report to be published in 2014. In addition, EPA released the results of a separate study concerning oil and gas development in Pavillion, Wyoming in December 2011 which suggests a link between hydraulic fracturing and groundwater contamination in the area. An independent peer-reviewed process has been instituted to review the findings. Certain states, including Wyoming, Colorado, Arkansas and Texas have adopted rules requiring drilling operators conducting hydraulic fracturing activities in those states to publically disclose the chemicals used in the fracturing process.

There has been increasing public controversy regarding hydraulic fracturing with regard to use of fracturing fluids, impacts on drinking water supplies, use of waters, and the potential for impacts to surface water, groundwater and the environment generally. A number of lawsuits and enforcement actions have been initiated in Texas and other states implicating hydraulic fracturing practices. Additional legislation or regulation 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.

These proposals may lead to additional levels of regulation at the federal, state or local level that could cause 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 our costs of compliance and doing business.

Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition, including litigation, to oil and gas production activities using hydraulic fracturing techniques. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of crude oil and natural gas, including from the developing shale plays, incurred by our customers or could make it more difficult to perform hydraulic fracturing. If these legislative and regulatory initiatives cause a material decrease in the drilling of new wells and related servicing activities, our business and profitability could be materially impacted.

We are responsible for the decommissioning, abandonment and reclamation costs for our facilities, which could decrease funds available for servicing our debt obligations and other operating expenses.

We are responsible for compliance with all applicable laws and regulations regarding the decommissioning, abandonment and reclamation of our facilities at the end of their economic life, including addressing environmental matters, the costs of which may be substantial. It is not possible to predict these costs with certainty since they will be a function of regulatory requirements at the time of decommissioning, abandonment and reclamation. We may, in the future, determine it prudent or be required by applicable laws or regulations to establish and fund one or more decommissioning, abandonment and reclamation reserve funds to provide for payment of future decommissioning, abandonment and reclamation costs, which could decrease funds available to service debt obligations. In addition, such reserves, if established, may not be sufficient to satisfy such future decommissioning, abandonment and reclamation costs and we will be responsible for the payment of the balance of such costs.

Item 1B. Unresolved Staff Comments.

None.

Item 2. Properties.

The information required by Item 2 is contained in "Item 1. Business."

Item 3. Legal Proceedings.

A putative class action lawsuit was filed by the Northumberland County Retirement System and Oklahoma Law Enforcement Retirement System in the District Court in Oklahoma County, Oklahoma, purportedly on March 10, 2011, against the Company and certain of its officers along with certain underwriters of the Company's July 2008, May 2009 and October 2009 public offerings. Discovery requests and summons were filed and issued, respectively, in late April 2011. The complaint alleges that the registration statement and the prospectus for the offering contained material misstatements and omissions and seek damages under Sections 11, 12 and 15 of the Securities Act of 1933 of an unspecified equitable relief. Defendants removed the case to federal court on May 12, 2011 and filed motions to dismiss on June 20, 2011. Plaintiffs filed a motion to remand the case to state court on June 10, 2011, and Defendants filed an opposition to that motion. By order dated November 16, 2011, the court denied Plaintiffs' motion to remand. On February 3, 2012, Plaintiffs moved to be appointed lead plaintiff under the Private Securities Litigation Reform Act. After the appointment of lead plaintiff, Plaintiffs are expected to file an amended complaint, with Defendants' responses thereto expected to be filed in early June 2012. We are currently unable to assess the probability of loss or estimate a range of potential loss, if any, associated with the securities class action case, which is at an early stage.

On August 5, 2011, an individual filed a shareholders' derivative action in the United States District Court for the Western District of Oklahoma, for the Company's benefit, as nominal defendant, against the Company's Chief Executive Officer, President, Chief Financial Officer, and certain members of the Company's board of directors. The complaint alleges breaches of fiduciary duty, waste of corporate assets, and unjust enrichment on the part of each of the named defendants and is premised on substantially the same facts alleged in the above-described securities lawsuit. The complaint seeks unspecified amounts of compensatory damages, implementation of certain corporate governance changes, and disgorgement of compensation and trading profits from the individual defendants, as well as interest and costs, including legal fees from the defendants. The Company is a nominal defendant, and the complaint does not seek any damages against the Company; however, the Company may have indemnification obligations to one or more of the defendants under the Company organizational documents. On

October 17, 2011, the individual defendants and the Company as nominal defendant filed motions to dismiss the complaint for failure to make demand, or in the alternative, to stay the derivative action pending the outcome of the securities lawsuit. The case is currently stayed pending the outcome of the motions to dismiss that are expected to be filed with respect to the securities lawsuit described above.

On February 7 and 9, 2012, two individuals filed separate shareholder derivative actions in the District Court of Oklahoma County, in the State of Oklahoma, for the Company's benefit, as nominal defendant, against the Company's Chief Executive Officer, President, Chief Financial Officer, and each member of the Company's board of directors. The petitions assert claims similar to those asserted in the federal court derivative action described above. Plaintiffs recently filed a motion to consolidate the two state court derivative actions, and the court consolidated the two actions. The parties are conferring about the schedule for the filing of an amended petition and defendants' responses thereto..

The Company is party to various legal actions arising in the normal course of business. Matters that are probable of unfavorable outcome to the Company and which can be reasonably estimated are accrued. Such accruals are based on information known about the matters, the Company's estimates of the outcomes of such matters, and its experience in contesting, litigating, and settling similar financial position or results of operations after consideration of recorded accruals.

Item 4. Mine Safety Disclosures.

Not applicable

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.

Common Stock

The high and low sales prices for our common stock as listed on The New York Stock Exchange during the periods described below were as follows:

	High	Low
Year Ended December 31, 2011		
First Quarter	$ 6.45	$ 4.15
Second Quarter	6.48	4.14
Third Quarter	5.36	1.90
Fourth Quarter	2.62	1.15
Year Ended December 31, 2010		
First Quarter	$ 15.00	$ 7.86
Second Quarter	9.62	6.00
Third Quarter	7.28	3.98
Fourth Quarter	5.95	4.05

As of March 2, 2012, there were 74 record owners of our common stock and an estimated 19,000 beneficial owners.

Dividend Policy

We have never declared or paid any cash dividends on our shares of common stock and do not anticipate paying any cash dividends on our shares of common stock in the foreseeable future. Currently, we intend to retain any future earnings for use in the operation and expansion of our business. Any future decision to pay cash dividends on our common stock will be at the discretion of our board of directors and will be dependent upon our financial condition, results of operations, capital requirements and other facts our board of directors may deem relevant. The declaration and payment of dividends is currently prohibited under the terms of the indenture governing our Senior Secured Notes and may be similarly restricted in the future.

Securities Authorized for Issuance under Equity Compensation Plans

The following table summarizes the number of outstanding options granted to employees and directors, as well as the number of securities remaining available for future issuance, under our equity compensation plans as of December 31, 2011.

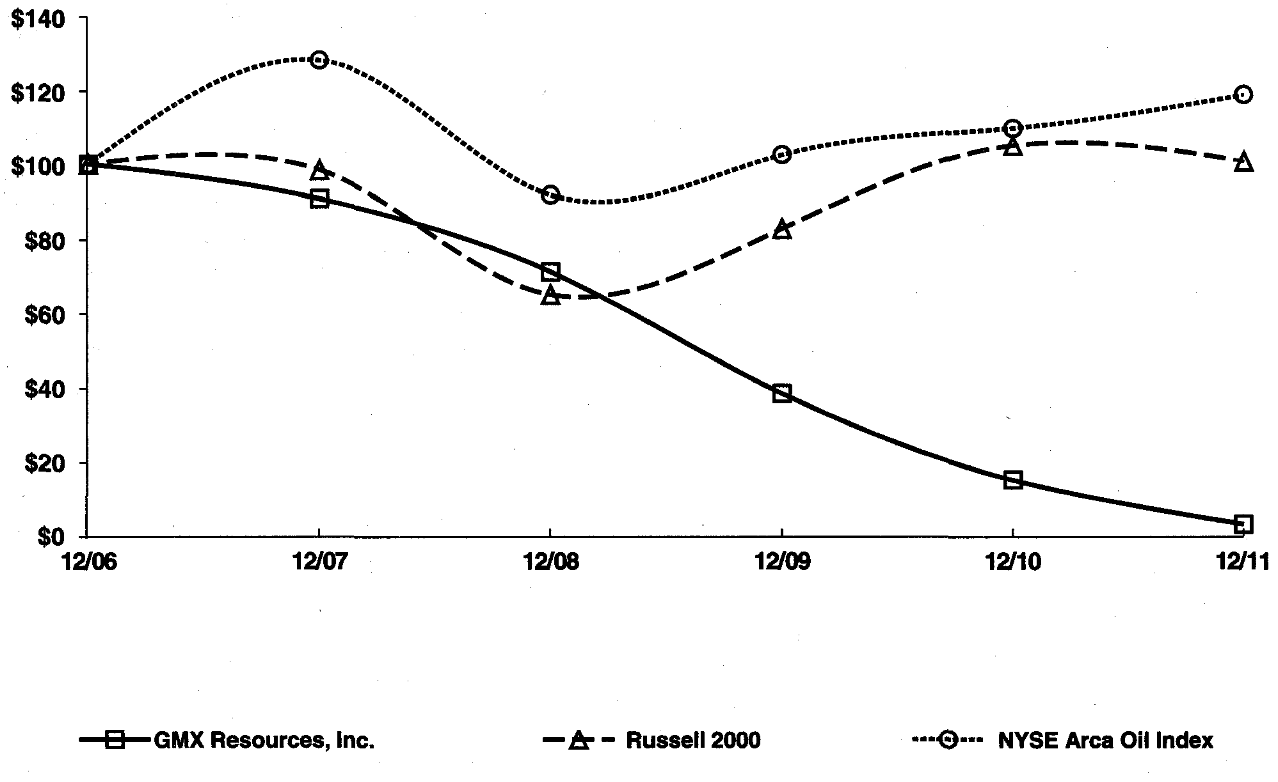
Plan Category	Number of securities to be issued upon exercise of outstanding options	Weighted-average exercise price of outstanding options	Number of securities remaining available for future issuance under equity compensation plans (excluding securities to be issued upon exercise of outstanding options)
Equity compensation plans approved by security holders	459,551	$ 27.17	1,312,759
Equity compensation plans not approved by security holders	—	$ —	—
Total	459,551	$ 27.17	1,312,759

Shareholder Return Performance Graph

The following graph compares the cumulative total shareholder returns of our Common Stock during the five years ended December 31, 2011 with the cumulative total shareholder returns of the Russell 2000 Index and the NYSE Arca Oil Index. The comparison assumes an investment of $100 on December 31, 2006 in each of our Common Stock, the Russell 2000 Index and the NYSE Arca Oil Index and that any dividends were reinvested.

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN*

Among GMX Resources, Inc., the Russell 2000 Index, and NYSE Arca Oil Index



*$100 invested on 12/31/06 in stock or index, including reinvestment of dividends.
Fiscal year ending December 31.

Purchases of Equity Securities

There were no repurchases of our common stock during for the year ended December 31, 2011.

Item 6. Selected Financial Data.

The following table presents our selective financial information for the periods indicated which were derived from our consolidated financial statements. It should be read in conjunction with our consolidated financial statements and related notes (beginning on page F-1 at the end of this report) and other financial information included herein.

	Year Ended December 31,				
	2011	2010	2009	2008	2007
	(in thousands, except share and per share data)				
Statement of Operations Data:					
Oil and natural gas sales	$ 116,741	$ 96,523	$ 94,294	$ 125,736	$ 67,883
Expenses:					
Lease operations	13,420	10,651	11,776	15,101	8,982
Production and severance taxes(1)	1,196	743	(930)	5,306	2,746
General and administrative	28,863	27,119	21,390	16,899	8,717
Depreciation, depletion and amortization	50,270	38,061	31,006	31,744	18,681
Impairment of oil and natural gas properties and assets held for sale	205,754	143,712	188,150	192,650	—
Total expenses	299,503	220,286	251,392	261,700	39,126
Income (loss) from operations	(182,762)	(123,763)	(157,098)	(135,964)	28,757
Total non-operating income (expense)	(23,071)	(18,768)	(24,022)	(14,174)	(3,862)
Income (loss) before income taxes	(205,833)	(142,531)	(181,120)	(150,138)	24,895
(Provision) benefit for income taxes	(615)	4,239	33	26,217	(8,010)
Net income (loss)	(206,448)	(138,292)	(181,087)	(123,921)	16,885
Net income attributable to non-controlling interest	5,389	3,114	173	—	—
Net income (loss) applicable to GMX	(211,837)	(141,406)	(181,260)	(123,921)	16,885
Preferred stock dividends	6,720	4,633	4,625	4,625	4,625
Net income (loss) applicable to GMX common shareholders	$ (218,557)	$ (146,039)	$ (185,885)	$ (128,546)	$ 12,260
Earnings (loss) per share—basic	$ (4.12)	$ (5.18)	$ (9.20)	$ (9.04)	$ 0.94
Earnings (loss) per share—diluted	$ (4.12)	$ (5.18)	$ (9.20)	$ (9.04)	$ 0.93
Weighted average common shares—basic	53,071,200	28,206,506	20,210,400	14,216,466	13,075,560
Weighted average common shares—diluted	53,071,200	28,206,506	20,210,400	14,216,466	13,208,746
Statement of Cash Flows Data:					
Cash provided by operating activities	$ 50,593	$ 58,735	$ 49,490	$ 83,237	$ 52,445
Cash used in investing activities	(189,569)	(176,000)	(181,324)	(318,360)	(194,998)
Cash provided by financing activities	239,112	84,068	160,672	235,932	143,500
Balance Sheet Data (at end of period):					
Oil and natural gas properties, net	$ 338,679	$ 347,763	$ 331,329	$ 383,890	$ 320,955
Total assets	542,201	507,090	522,071	525,001	395,340
Long-term debt, including current portion	426,831	284,969	190,278	224,342	125,734
Total GMX equity	55,740	116,420	246,380	246,797	208,926

(1) Production and severance taxes in 2011, 2010, 2009, 2008 and 2007 reflect severance tax refunds of $3.5 million, $3.1 million, $2.9 million, $1.2 million and $518,000, respectively, received and accrued during the year.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

Summary Operating and Reserve Data

The following table presents an unaudited summary of oil and natural gas production, production prices, production costs and oil and natural gas reserve data for the periods indicated.

	Year Ended December 31,				
	2011 (5)	2010	2009	2008	2007
Production:					
Oil (MBbls)	93	95	119	190	127
Natural gas (MMcf)	20,918	14,755	12,908	11,777	7,974
Natural gas liquids (Mgals) (6)	14,292	15,024	—	—	—
Gas equivalent (MMcfe)	23,516	17,474	13,620	12,918	8,735
Natural gas VPP volumes (MMcfe)	450	—	—	—	—
Gas equivalent production including VPP volumes (MMcfe)	23,967	17,474	13,620	12,918	8,735
Average daily excluding VPP volumes (MMcfe)	64.4	47.9	37.3	35.3	23.9
Average daily including VPP volumes (MMcfe)	65.7	47.9	37.3	35.3	23.9
Average Sales Price:					
Oil (per Bbl)					
Wellhead price	$ 92.80	$ 76.77	$ 56.61	$ 99.16	$ 71.08
Effect of hedges, excluding gain or loss from ineffectiveness of derivatives	(0.47)	—	19.41	(10.66)	(1.97)
Total	$ 92.33	$ 76.77	$ 76.02	$ 88.50	$ 69.11
Natural gas liquids (per gallon) (6)					
Sales price	$ 0.98	$ 0.79	$ —	$ —	$ —
Effect of hedges, excluding gain or loss from ineffectiveness of derivatives	—	—	—	—	—
Total	$ 0.98	$ 0.79	$ —	$ —	$ —
Natural gas (per Mcf)					
Wellhead price	$ 3.60	$ 3.73	$ 3.85	$ 9.50	$ 7.00
Effect of hedges, excluding gain or loss from ineffectiveness of derivatives	0.90	1.60	2.68	(0.34)	0.41
Total	$ 4.50	$ 5.33	$ 6.53	$ 9.16	$ 7.41
Average sales price, excluding gain or loss from ineffectiveness of derivatives (per Mcfe)	$ 4.96	$ 5.60	$ 6.85	$ 9.65	$ 7.77
Operating and Overhead Costs (per Mcfe):					
Lease operating expenses(4)	$ 0.56	$ 0.61	$ 0.86	$ 1.17	$ 1.03
Production and severance taxes	0.05	0.04	(0.07)	0.41	0.31
General and administrative	1.20	1.56	1.57	1.31	1.00
Total	$ 1.81	$ 2.21	$ 2.36	$ 2.89	$ 2.34
Other (per Mcfe):					
Depreciation, depletion and amortization—oil and natural gas production	$ 1.88	$ 1.88	$ 1.76	$ 2.08	$ 1.88
Estimated Net Proved Reserves (as of period-end):					
Natural gas (Bcf)	274.9	312.0	333.2	435.3	406.3
Oil (MMbls)	1.7	1.2	3.7	5.0	4.7
Total (Bcfe)	285.3	319.3	355.3	465.3	434.5
Estimated Future Net Revenues ($MM)(1)(2)	$ 619.6	$ 692.7	$ 625.7	$ 1,012.3	$ 1,896.3
Present Value ($MM)(1)(2)	$ 186.6	$ 249.9	$ 188.6	$ 280.7	$ 592.8
Standardized measure of discounted future net cash flows ($MM)(3)	$ 186.6	$ 249.9	$ 188.6	$ 228.8	$ 427.7

(1) See "Item 1 Business—Certain Technical Terms."

(2) The 2011, 2010 and 2009 prices used in calculating Estimated Future Net Revenues and the Present Value are determined using prices as prescribed by the SEC. Estimated Future Net Revenues and the Present Value give no effect to federal or state income taxes attributable to estimated future net revenues.

(3) The standardized measure of discounted future net cash flows give effect to federal and state income taxes attributable to estimated future net revenues. In years where our effective tax rate is 0%, there is no effect to the standardized measure for federal or state taxes as was the case in 2011, 2010 and 2009. See "Note M—Supplemental Information on Oil and Natural Gas Operations" in our consolidated financial statements.

(4) Lease operating expenses include ad valorem taxes which increases the per Mcfe cost by $0.07, $0.09, $0.06, $0.10, $0.01 and $0.06 in 2011, 2010, 2009, 2008 and 2007, respectively.

(5) For 2011, the amounts presented are net of the Volumetric Production Payment ("VPP") volumes, with exception of "Operating and Overhead Costs (per Mcfe)," which are presented gross of the VPP volumes.

(6) Natural gas liquids ("NGL") are presented for 2011 and 2010 only. For 2009, 2008 and 2007, the Company included natural gas liquids as part of the natural gas reserves.

We are an independent oil and gas company historically engaged in the exploration, development and production of oil and natural gas from the Haynesville/Bossier Shale and Cotton Valley Sands in our core area, the Sabine Uplift of the Carthage, North Field of Harrison and Panola counties of East Texas. For all periods we consider and report all of our operations as one segment because our operating areas have similar economic characteristics and each meet the criteria for aggregation as defined in the Financial Accounting Standards Board Accounting Standards Codification 280.

During 2010, we focused on the development of our Haynesville/Bossier ("H/B") Shale horizontal well development as well as Cotton Valley Sand wells, which are substantially all natural gas wells. During 2011, we began to shift our focus from our core area into the Bakken and Niobrara formations in which we have acquired undeveloped acreage that consist of oil-focused resource plays.

Results of Operations—Year ended December 31, 2011 Compared to Year ended December 31, 2010

Oil and Natural Gas Sales. Oil and natural gas sales during the year ended December 31, 2011 increased 21% to $116.7 million compared to $96.5 million during the year ended December 31, 2010. Oil and natural gas sales included gains (losses) from the ineffectiveness from derivatives of $0.1 million and $(1.3) million for the year ended December 31, 2011 and 2010, respectively, and are the result of a difference in the fair value of our cash flow hedges and the fair value of the projected cash flows of a hypothetical derivative based on our expected sales point. The increase in oil and natural gas sales was due to a 35% increase in production on a Bcfe-basis, a 20% increase in oil prices, a 24% increase in the average realized price of NGLs, offset by a 16% decrease in the average realized price of natural gas, excluding ineffectiveness of hedging activities. The average price per barrel of oil, per gallon of natural gas liquids NGLs and Mcf of natural gas received (excluding ineffectiveness from derivatives) in the year ended December 31, 2011 was $92.33, $0.98 and $4.50, respectively, compared to $76.77, $0.79 and $5.33, respectively, for the year ended December 31, 2010. Our realized sales price for natural gas, excluding the effect of hedges of $0.90 and $1.60, for the year ended December 31, 2011 and 2010, respectively, was approximately 89% and 85% of the average NYMEX closing contract price for the respective periods. During the year ended December 31, 2011 and 2010 , the conversion of natural gas to NGLs produced an upgrade of approximately $0.67 per Mcf and $0.81 per Mcf, respectively, for every Mcf of natural gas produced. This upgrade in value was previously included in the realized price of our natural gas sales.

Production for the year ended December 31, 2011, increased to 24.0 Bcfe, which includes the production of 0.45 Bcfe related to VPP, compared to 17.5 Bcfe for the year ended December 31, 2010, an increase of 37%. We completed and brought on-line 8 H/B wells during 2011, which contributed to the increase in gas production for the period. During the first quarter of 2011, we began to separate and report the production and revenue from our NGLs, compared to prior periods in which we had included NGL production and revenues in our natural gas production and sales amounts. NGL production for the year ended December 31, 2011 decreased to 14,292 Mgals compared to 15,024 Mgals for the year ended December 31, 2010, a decrease of 4.9%. This decrease was due to a decrease in production in our non-Haynesville production for the year ended December 31, 2011, which has a higher NGL content compared to our H/B wells.

For the year ended December 31, 2011, as a result of hedging activities, excluding derivative ineffectiveness, we recognized an increase in natural gas sales of $18.7 million compared to an increase in natural gas sales of $23.6 million for the year ended December 31, 2010. The effect of our derivative contracts on oil had a $(0.47) per barrel impact in 2011 and no impact in 2010.

Lease Operations. Lease operations expense increased $2.7 million, or 25%, for the year ended December 31, 2011 to $13.4 million, compared to $10.7 million for the year ended December 31, 2010. Lease operations expense on an equivalent unit of production basis decreased $0.05 per Mcfe for the year ended December 31, 2011 to $0.56 per Mcfe, including VPP volumes, compared to $0.61 per Mcfe for the year ended December 31, 2010. The decrease in lease operations expense on an equivalent unit basis resulted from an increase in Haynesville/Bossier horizontal well production and cost control measures implemented by us during 2010, which lowered overall lease operating expense. With little to no incremental increase in lease operations cost from a Cotton Valley vertical well, the significantly larger amount of production from a H/B horizontal well will result in lower per unit lease operations costs. The overall increase in lease operations expense is primarily related to higher gathering costs plus an increase in salt water disposal expense related to the increase in production for the year ended December 31, 2011 compared to the year ended December 31, 2010.

Production and Severance Taxes. The State of Texas grants an exemption of severance taxes for wells that qualify as "high cost" wells. Certain wells, including all of our H/B wells, qualify for full severance tax relief for a period of ten years or recovery of 50% of the cost of drilling and completions, whichever is less. As a result, refunds for severance tax paid to the State of Texas on wells that qualify for reimbursement are recognized as accounts receivable and offset severance tax expense for the amount refundable. Production and severance taxes increased 61% to $1.2 million for the year ended December 31, 2011 compared to $0.7 million for the year ended December 31, 2010.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense increased $12.2 million, or 32%, to $50.3 million for the year ended December 31, 2011 compared to $38.1 million for the year ended December 31, 2010. The oil and gas properties depreciation, depletion and amortization rate per equivalent unit of production was $1.88 per Mcfe for both the years ended December 31, 2011 and 2010. The increase in the depreciation, depletion and amortization expense is due to the increase in production during 2011.

Impairment of oil and natural gas properties. For the $205.8 million non-cash impairment charge recorded in the year ended 2011, $196.4 million of the charge was related to the impairment of oil and gas properties subject to the full cost ceiling test and $9.3 million was related to a change in value of assets held for sale. The primary factors impacting the full cost method ceiling test are expenditures added to the full cost pool, reserve levels, value of cash flow hedges and natural gas and oil prices, and their associated impact on the present value of estimated future net revenues. Any excess of the net book value is generally written off as an expense. Revisions to estimates of natural gas and oil reserves and/or an increase or decrease in prices can have a material impact on the present value of estimated future net revenues. Natural gas represents 96% of the Company's total proved reserves, and as a result, a decrease in natural gas prices can significantly impact the Company's ceiling test. During the year ended December 31, 2011, the 12-month average of the first day of the month natural gas price decreased 6% from $4.38 per MMbtu at December 31, 2010 to $4.12 per MMbtu at December 31, 2011. Of the $196.4 million related to the impairment of oil and gas properties, $121.4 million resulted from the net book value of oil and gas properties exceeding the net present value of future net revenues, $52.3 million related to the monetization of the cash flow hedges that were used in the full cost ceiling test and $22.7 million related to the acquisition cost of East Texas and North Louisiana undeveloped acreage outside of our primary development area being subject to the full cost method ceiling test. Approximately $9.3 million of the $205.8 million impairment charge was related to impairment on the Company's three drilling rigs and other inventory and equipment, previously classified in assets held for sale and that were sold in 2011.

General and Administrative Expense. General and administrative expense for the year ended December 31, 2011 was $28.9 million compared to $27.1 million for the year ended December 31, 2010, an increase of $1.8 million, or 6%. General and administrative expense per equivalent unit of production was $1.20 per Mcfe, including VPP volumes, for the year ended December 31, 2011 compared to $1.56 per Mcfe for the comparable period in 2010. The overall increase in general and administrative expense for the year ended December 31, 2011 compared to the year ended December 31, 2010 was primarily due to approximately $1.3 million in expenses for the year ended December 31, 2011, for legal fees related to the VPP and other matters. General and administrative expenses include $3.7 million and $5.5 million of non-cash compensation expense as of the year ended December 31, 2011 and 2010, respectively. Non-cash compensation represented 13% and 20% of total general and administrative expenses for the year ended December 31, 2011 and 2010, respectively. General and administrative expense has not historically varied in direct proportion to oil and natural gas production because certain types of general and administrative expenses are non-recurring or fixed in nature.

Interest. Interest expense for the year ended December 31, 2011 was $31.9 million compared to $18.6 million for the same period in 2010. For the year ended December 31, 2011 and 2010, interest expense includes non-cash interest expense of $5.9 million and $6.5 million, respectively, related to the accounting for convertible bonds, our share lending agreement and deferred premiums on derivative instruments. Cash interest expense for the year ended December 31, 2011 and 2010 was $30.3 million and $12.0 million, respectively, of which $7.8 million and $2.6 million, respectively was capitalized to properties not subject to amortization on the consolidated balance sheets. The increase in cash interest expense of $18.3 million was mainly due to the Company's issuance and sale in February 2011 of $200 million aggregate principal amount of Senior Notes due 2019.

Income Taxes. Income tax for the year ended December 31, 2011 was a provision of $0.6 million as compared to a benefit of $4.2 million in the same period in 2010. The income tax expense and benefit recognized for the year ended December 31, 2011 and 2010, respectively, were a result of a change in the valuation allowance on net deferred tax assets caused by a change in deferred tax liabilities primarily related to unrealized gains on derivative contracts designated as hedges where the mark-to-market change on the hedges, net of deferred taxes is recorded to other comprehensive income.

Net income to noncontrolling interest. Net income to noncontrolling interest increased to $5.4 million for the year ended December 31, 2011 compared to $3.1 million for the year ended December 31, 2010. The increase is due to an increase in the gathering fees earned by our majority-owned subsidiary in which the outside noncontrolling interest member is currently allocated 80% of the distributions. The gathering fees earned by the subsidiary increased as a result of an increase in production from the H/B horizontal wells that were completed and brought online.

Year ended December 31, 2010 Compared to Year ended December 31, 2009

Certain amounts in 2009 have been adjusted as disclosed in "Note B—Share Lending Arrangements and Adoption of ASU 2009-15," to the consolidated financial statements and reflect retrospective adjustments for the adoption of ASC 2009-15.

Oil and Natural Gas Sales. Oil and natural gas sales in the year ended December 31, 2010 increased 2% to $96.5 million compared to the year ended December 31, 2009. This sales increase is primarily due to an increase in natural gas and oil production of 28%, offset by a decrease in natural gas and oil prices of 18%, net of effect of hedging. The average prices per barrel of oil and mcf of natural gas received in the year ended December 31, 2010 were $76.77 and $5.35, respectively, compared to $76.02 and $6.53, respectively, in the year ended December 31, 2009. Oil production in 2010 decreased to 95 MBbls compared to 119 MBbls for 2009. The decrease in oil production is due to the natural decline in the Company's Cotton Valley Sands vertical well production, which has historically provided most of the Company's oil production. H/B Hz wells typically do not have oil production. Natural gas production in 2010 increased to 16,901 MMcf for 2010 compared to 12,908 MMcf for the year ended December 31, 2009, an increase of 31%. The increase in natural gas production resulted from 19 additional producing H/B Hz wells that were completed and brought on-line during 2010 and the respective production exceeding the normal decline in production for wells producing at the beginning of the period. Production from H/B Hz wells accounted for 63% of total production for 2010 compared to 33% for 2009.

In the year ended December 31, 2010, as a result of hedging activities, we recognized an increase in oil and natural gas sales of $22.3 million, compared to an increase in oil and natural gas sales of $37.9 million in the year ended December 31, 2009. In the year ended December 31, 2010, hedging, excluding ineffectiveness, increased the average natural gas sales price by $1.39 per Mcf compared to an increase of the average natural gas and oil sales price by $2.68 per Mcf and $19.41 per Bbl in the year ended December 31, 2009. Oil related derivative instruments had no impact on oil and natural gas sales in 2010.

Lease Operations. Lease operations expense decreased $1.1 million in the year ended December 31, 2010 to $10.7 million, a 10% decrease compared to $11.8 million in the year ended December 31, 2009. Lease operating expense on an equivalent unit of production basis was $0.61 per Mcfe in the year ended December 31, 2010 compared to $0.86 per Mcfe for the year ended December 31, 2009. The decrease in lease operating expenses on an equivalent unit basis resulted from a higher volume H/B Hz well production relative to the corresponding lease operations expense per well and cost control measures implemented during 2010. With little to no incremental increase in lease operating costs from a typical Cotton Valley vertical well, the significantly larger amount of production from a typical H/B Hz well results in lower per unit lease operating costs.

Production and Severance Taxes. The State of Texas grants an exemption of severance taxes for wells that qualify as "high cost" wells. Certain wells, including all of our H/B wells, qualify for severance tax relief for a period of ten years or recovery of 50% of the cost of drilling and completion, whichever is less. As a result, refunds for severance tax paid to the State of Texas on wells that qualify for reimbursement are recognized as accounts receivable and offset severance tax expense for the amount refundable (net of filing fees paid to a third party). Production and severance taxes increased 180% to a an expense of $0.7 million for the year ended December 31, 2010 compared to a benefit of $0.9 million for the year ended December 31, 2009, as a result of the Company recording production and severance tax refunds of $2.9 million offset by production and severance tax funds receivable of $1.3 million for the year ended December 31, 2009 for severance taxes paid in 2009 and prior for which reimbursement was due.

General and Administrative Expense. General and administrative expense for the year ended December 31, 2010 was $27.1 million compared to $21.4 million for the year ended December 31, 2009, an increase of 27%. An increase of $5.7 million was due to an increase in administrative and supervisory personnel, severance compensation, as well as in increase in corporate operating expenses due to our expected growth. General and administrative expense per equivalent unit of production was $1.55 per Mcfe for the year ended December 31, 2010 compared to $1.57 per Mcfe for the comparable period in 2009. Approximately $5.5 million or 20% of the general and administrative expenses in 2010 was related to non-cash compensation expense compared to $4.6 million or 22% in 2009. General and administrative expense has not historically varied in direct proportion to oil and natural gas production because certain types of general and administrative expenses are non-recurring or fixed in nature. The Company expects general and administrative expenses on a per Mcfe basis to decrease as production increases.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense increased $7.1 million to $38.1 million in the year ended December 31, 2010, up 23% from $31.0 million in the year ended December 31, 2009. The oil and gas properties depreciation, depletion and amortization rate per equivalent unit of production was $1.88 per Mcfe in the year ended December 31, 2010 compared to $1.76 per Mcfe in the year ended December 31, 2009. The increase is due to current year production being a greater percentage of the total proved reserves as a result of negative reserve revisions to the Cotton Valley proved reserves in 2010.

Impairment of oil and natural gas properties and assets held for sale. The removal of the Company's proved undeveloped Cotton Valley Sand Reserves from the year end 2010 reserve report and the reduction in the present value at 10% of the reserves has limited the amount of oil and gas properties that could be capitalized on the balance sheet under the SEC's "ceiling" test. We recognized an impairment charge on oil and gas properties of $132.8 million in the year ended December 31, 2010 compared to an impairment charge on oil and gas properties of $188.2 million in the year ended December 31, 2009. The Company may be required to recognize additional impairment charges or writedowns in future reporting periods if market prices for oil decline and market prices for natural gas continue to decline or remain at their depressed levels. In addition, the Company impaired an additional $10.9 million related to assets held for sale as of December 31, 2010.

Interest. Interest expense for the year ended December 31, 2010 was $18.6 million compared to $16.7 million for the year ended December 31, 2009. This increase is due to a higher amount of outstanding debt during 2010, as well as non-cash interest expense relating to the amortization of the discount of the deferred premiums on derivative instruments. Interest expense for the years ended December 31, 2010 and 2009 includes non-cash interest expense of $4.9 million and $3.9 million, respectively related to the accretion of the 5.00% senior convertible notes due 2013 and the 4.50% convertible senior notes due 2015. Interest expense for 2010 and 2009 also includes amortization of the discount related to our share lending agreement of $0.7 million and $0.6 million, respectively, under the accounting rules adopted in 2010 (see Note B). In addition, interest expense for 2010 includes $0.8 million of amortized discount related to the deferred premiums, which began during 2010.

Income Taxes. Income tax for 2010 was a benefit of $4.2 million as compared to a benefit of $33,000 in 2009. Virtually all of the Company's deferred tax assets are reserved except to the extent offset by deferred tax liabilities and provisions that are recorded for items included in Accumulated Other Comprehensive Income. Deferred tax liabilities for items included in Accumulated Other Comprehensive Income increased by $4.2 million in 2010, which resulted in the recognition (benefit) of $4.2 million for the change in valuation allowance or net of deferred tax assets. The effective tax rates for 2010 and 2009 were 3% and 0%, respectively.

Net Loss Applicable to GMX Shareholders and Net Loss per Share

Net Loss Applicable to GMX Shareholders and Net Loss Per Share—Year Ended December 31, 2011 Compared to Year Ended December 31, 2010. For the years ended December 31, 2011 and 2010, we reported net loss applicable to the Company's shareholders of $218.6 million and $146.0 million, respectively. Net loss applicable to the Company's shareholders per basic and fully diluted share was $4.12 for the year ended 2011 compared to net loss applicable to the Company's shareholders per basic and fully diluted share of $5.18 for the year ended 2010.

Net Loss Applicable to GMX Shareholders and Net Loss Per Share—Year Ended December 31, 2010 Compared to Year Ended December 31, 2009. For the year ended December 31, 2010 and 2009, we reported net loss applicable to the Company's shareholders of $146.0 million and $185.9 million, respectively. Net loss applicable to the Company's shareholders per basic and fully diluted share was $5.18 for the year ended 2010 compared to net loss applicable to the Company's shareholders per basic and fully diluted share of $9.20 for the year ended 2009.

Capital Resources and Liquidity

Our business is capital intensive. Our ability to grow our reserve base is dependent upon our ability to obtain outside capital and generate cash flows from operating activities to fund our drilling and capital expenditures. Our cash flows from operating activities are substantially dependent upon crude oil and natural gas prices, and significant decreases in market prices of crude oil or natural gas could result in reductions of cash flow and affect our drilling and capital expenditure plan. To mitigate a portion of our exposure to fluctuations in natural gas prices, we have historically entered into natural gas swaps, three-way collars and put spreads. As a result of paying off our bank credit facility and to increase current liquidity, the Company monetized its remaining natural gas hedge portfolio in December 2011. The Company received $18.5 million, net of deferred premiums payable. We plan to continue to hedge oil and natural gas in the future to mitigate our commodity price risk.

We continually review our drilling and capital expenditure plans and may change the amount we spend based on industry and market conditions and the availability of capital. For the year ended December 31, 2011, our cash outlays for capital expenditures were $272 million, of which $126 million was the cash portion of acreage acquisitions and seismic in the Williston Basin, DJ Basin-Niobrara and East Texas, $124 million was for drilling operations, and $22 million related to capitalized interest, corporate expenditures and rig sub-lease fees. Of the $124 million in capital expenditures for drilling operations, $16.2 million related to drilling operations in the Williston Basin-Niobrara and $107.8 million related to East Texas drilling and other capital expenditures. We have elected to temporarily suspend execution of our H/B Hz program until natural gas prices or lower completed well costs support more economical drilling, which we expect to occur by mid-year 2014.

As of December 31, 2011, we had $106.8 million of cash and cash equivalents, including $4.3 million in restricted cash. Through the period ended December 31, 2011, we have funded our operating expenses and capital expenditures through positive operating cash flows, as well as from $105.3 million raised from the issuance of 22,173,518 shares of our common stock in February 2011, $25.8 million raised from the issuance of 1,135,565 shares of our 9.25% Series B Cumulative Preferred Stock preferred shares, $193.7 million, net of original issue discount, raised from the issuance of our 11.375% senior notes, $49.7 million in connection with the VPP, $21.2 million from the settlement of our oil and natural gas hedge portfolio, net of premiums payable, and $100 million raised from a bond exchange of our 11.375% Senior Notes due 2019 for our new Senior Secured Notes due 2017.

The outstanding balance of our bank credit facility at the time of the offerings in February 2011 of $110 million was fully repaid, and we completed a $50 million tender offer for a portion of our 5.00% convertible notes. The remaining proceeds from the offerings were used to fund the Niobrara and Bakken acreage acquisitions and other capital expenditures. On December 12, 2011, the Company fully repaid the outstanding balance on our bank credit facility of $39.1 million and terminated this credit agreement.

We anticipate funding approximately $97 million of cash capital expenditures in 2012 with cash on hand, positive operating cash flow, and a partial sale of our Niobrara acreage or other potential capital market activities. The 2012 capital expenditure budget will focus on our Bakken development plans. In the Bakken, we are currently running one rig from Paramount Drilling U.S. LLC. Based on available liquidity, we plan to add a second rig in the Bakken during the third quarter of 2012. In the Niobrara for 2012, we are budgeting for participating in a Devon Energy operated well, and will continue to evaluate our seismic work and surrounding well results from other operators.

Cash Flow—Year Ended December 31, 2011 Compared to Year Ended December 31, 2010. In 2011, we had a positive cash flow from operating activities of $50.6 million. Our cash flow from operating activities in 2010 was $58.7 million. We received a net $239.1 million in cash from financing activities in 2011 compared to $84.1 million in 2010. The cash flow from financing activities in 2011 was primarily from draws on our line of credit totaling $70.5 million, which was repaid in full by the end of 2011; $193.7 million from the issuance of our 11.0% Senior Notes due 2019, of which a substantial portion was exchanged in December 2011 for the Senior Secured Notes; $105.3 million from the issuance of our common stock and $100.0 million related to the issuance of our Senior Secured Notes. In 2011, we repaid $50 million of the outstanding balance on our 5.00% Senior Convertible Notes due 2013 with proceeds from our common stock and Senior Notes offerings.

Cash Flow—Year Ended December 31, 2010 Compared to Year Ended December 31, 2009. In 2010, we had a positive cash flow from operating activities of $58.7 million. Our cash flow from operating activities in 2009 was $49.5 million. We received a net $84.1 million in cash from financing activities in 2010 compared to 2009 amounts of $160.7 million. The cash flow from financing activities in 2010 was primarily from draws on our line of credit totaling $92 million, sale of preferred stock of $0.9 million and contributions from our non-controlling interest holder of $1.2 million, offset by dividend payments on our Series B preferred stock of $4.6 million, distributions to our non-controlling interest member of $4.6 million and financing fees of $0.9 million. The cash flow from financing activities in 2009 was primarily from the sale of common stock of $164.1 million, issuance of 4.50% convertible senior notes due 2015 of $86.3 million, and the sale of the equity interest in Endeavor Gathering for $36.0 million, offset by a pay down of debt under our revolving bank credit facility and Senior Secured Notes totaling $213.7 million.

Revolving Bank Credit Facility and Other Debt

Revolving Bank Credit Facility. On December 12, 2011, we fully repaid the outstanding balance on our secured revolving bank credit facility of $39.1 million and terminated the bank credit facility in connection with the closing of the volumetric production payment transaction. There were no amounts outstanding under any new revolving credit facilities as of December 31, 2011. On the date of termination, we had $1.6 million in unamortized debt issue costs, which was expensed and included in gain (loss) on extinguishment of debt.

5.00% Convertible Senior Notes Due 2013. In February 2008, we completed a $125 million private placement of 5.00% Convertible Senior Notes due 2013 (the "5.00% Convertible Notes"). Net proceeds of approximately $121 million were used to repay our revolving bank credit facility and other indebtedness. The 5.00% Convertible Notes are governed by an indenture, dated as of February 15, 2008 (the "5.00% Convertible Notes Indenture") between the Company and The Bank of New York

Trust Company, N.A., as trustee (the "Trustee").

The 5.00% Convertible Notes bear interest at a rate of 5.00% per year, payable semiannually in arrears on February 1 and August 1 of each year, beginning August 1, 2008. The 5.00% Convertible Notes mature on February 1, 2013, unless earlier converted or repurchased by us. Holders may convert their 5.00% Convertible Notes at their option prior to the close of business on the business day immediately preceding November 1, 2012 only under the following circumstances:

- during any fiscal quarter commencing after March 31, 2008 if the last reported sale price of our common stock for at least 20 trading days during a period of 30 consecutive trading days ending on the last trading day of the preceding fiscal quarter is greater than or equal to 130% of the applicable conversion price on each such trading day;
- during the five business-day period after any five consecutive trading-day period in which the trading price per $1,000 principal amount of 5.00% Convertible Notes for each day of that measurement period was less than 98% of the product of the last reported sale price of our common stock and the applicable conversion rate on each such day;
- upon the occurrence of a corporate event pursuant to which: (1) we issue rights to all or substantially all of the holders of our common stock entitling them to purchase, for a period expiring within 60 days after the date of the distribution, shares of our common stock at a price below the average market price at the time, or (2) we distribute to all or substantially all of the holders of our common stock our assets, debt securities or rights to purchase our securities, if the distribution has a per share value in excess of 10% of the last reported sale price for our common stock at the time; or
- if: (1) a "person" or "group" within the meaning of Section 13(d) of the Exchange Act acquires more than 50% of our outstanding voting stock, (2) we consummate a recapitalization, reclassification or change of our common stock as a result of which our common stock would be converted into or exchanged for stock, other securities, other property or assets, (3) we consummate a share exchange, consolidation or merger pursuant to which our common stock will be converted into cash, securities or other property, (4) we consummate any sale, lease or other transfer in one transaction or a series of transactions of all or substantially all of our and our subsidiaries' consolidated assets to any person other than one of our subsidiaries, (5) continuing directors cease to constitute at least a majority of our board of directors, (6) our shareholders approve any plan or proposal for our liquidation or dissolution, or (7) our common stock ceases to be listed on a United States national or regional securities exchange (any of the events described in clauses (1) through (7), a "fundamental change").

On and after November 1, 2012 until the close of business on the business day immediately preceding the maturity date, holders may convert their 5.00% Convertible Notes at any time, regardless of the foregoing circumstances.

Upon conversion, we will satisfy our conversion obligation by paying and delivering cash for the lesser of the principal amount or the conversion value, and, if the conversion value is in excess of the principal amount, by paying or delivering, at our option, cash and/or shares of our common stock for such excess. The conversion value is a daily value calculated on a proportionate basis for each day of a 60 trading-day observation period.

The conversion rate is initially 30.7692 shares of our common stock per $1,000 principal amount of 5.00% Convertible Notes (equivalent to a conversion price of approximately $32.50 per share of common stock). The conversion rate is subject to adjustment in some events but will not be adjusted for accrued interest. In addition, following any fundamental change that occurs prior to the maturity date, we will increase the conversion rate for a holder who elects to convert its 5.00% Convertible Notes in connection with such a fundamental change in certain circumstances. The increase in the conversion rate is determined based on a formula that takes into consideration our stock price at the time of the fundamental change (ranging from $25.00 to $150.00 per share) and the remaining time to maturity of the 5.00% Convertible Notes. The increase in the conversion rate ranges from 0% to 30%, increasing as the stock price at the time of the fundamental change increases from $25.00 and declining as the remaining time to maturity of the 5.00% Convertible Notes decreases.

We may not redeem the 5.00% Convertible Notes prior to maturity. However, if we undergo a fundamental change, holders may require us to repurchase the 5.00% Convertible Notes in whole or in part for cash at a price equal to 100% of the principal amount of the 5.00% Convertible Notes to be repurchased plus any accrued and unpaid interest (including additional interest, if any) to, but excluding, the fundamental change repurchase date.

The 5.00% Convertible Notes are senior unsecured obligations of the Company and rank equally in right of payment to all of our other existing and future senior indebtedness and our existing 4.50% Convertible Notes discussed below. The 5.00% Convertible Notes are effectively subordinated to all our secured indebtedness, including our Senior Secured Notes, to the extent of the value of our assets pledged as collateral for such indebtedness. The 5.00% Convertible Notes are also effectively subordinated to all liabilities of our subsidiaries, including liabilities under any guarantees they have issued.

On January 28, 2011, we announced the commencement of a tender offer for up to $50 million aggregate principal amount of the outstanding 5.00% Convertible Notes. The tender offer expired March 11, 2011 and we retired $50 million aggregate principal amount of the 5.00% Convertible Notes.

4.50% Convertible Senior Notes Due 2015. In October 2009, we completed an $86.3 million public offering of 4.50% convertible senior notes due 2015 ("4.50% Convertible Notes"). The proceeds of the offering were used to repay the Senior Subordinated Secured Notes due 2012 and a portion of the outstanding indebtedness under the revolving bank credit facility.

The 4.50% Convertible Notes bear interest at a rate of 4.50% per year, payable semiannually in arrears on May 1 and November 1 of each year, beginning May 1, 2010. The 4.50% Convertible Notes mature on May 1, 2015, unless earlier converted or repurchased by us. Holders may convert their notes prior to the close of business on the business day immediately preceding February 1, 2015, only under the following circumstances:

- during any fiscal quarter commencing after January 1, 2010, if the last reported sale price of our common stock for at least 20 trading days during a period of 30 consecutive trading days ending on the last trading day of the preceding fiscal quarter is greater than or equal to 130% of the applicable conversion price on each such trading day;
- during the five business-day period after any five consecutive trading-day period in which the trading price per $1,000 principal amount of 4.50% Convertible Notes for each day of such five consecutive trading-day period was less than 98% of the product of the last reported sale price of our common stock and the applicable conversion rate on each such day;
- upon the occurrence of a corporate event pursuant to which: (1) we issue rights to all or substantially all of the holders of our common stock entitling them to purchase, for a period of not more than 60 calendar days after the announcement date of such issuance to subscribe for or purchase, shares of our common stock at a price per share less than the average of the last reported sale prices of our common stock for the 10 consecutive trading day period ending on the trading day immediately preceding the date of announcement of such issuance; (2) we distribute to all or substantially all of the holders of our common stock our assets, debt securities or rights to purchase our securities, if the distribution has a per share value in excess of 10% of the last reported sale price for our common stock on the trading day immediately preceding the date of announcement of such distribution; or (3) we are a party to a consolidation, merger, binding share exchange, or transfer or lease of all or substantially all of our assets, pursuant to which our common stock would be converted into cash, securities or other assets;
- if: (1) a "person" or "group" within the meaning of Section 13(d) of the Exchange Act acquires more than 50% of our outstanding voting stock, (2) we consummate a recapitalization, reclassification or change of our common stock as a result of which our common stock would be converted into or exchanged for stock, other securities, other property or assets, less than 90% of which received by our common shareholders consists of publicly traded securities, (3) we consummate a share exchange, consolidation or merger pursuant to which our common stock will be converted into cash, securities or other property, (4) we consummate any sale, lease or other transfer in one transaction or a series of transactions of all or substantially all of our and our subsidiaries' consolidated assets to any person other than one of our subsidiaries, (5) continuing directors cease to constitute at least a majority of our board of directors, (6) our shareholders approve any plan or proposal for our liquidation or dissolution, or (7) our common stock ceases to be listed on any of The New York Stock Exchange, The NASDAQ Global Select Market or The NASDAQ Global Market; or
- if we call the 4.50% Convertible Notes for redemption, at any time prior to the close of business on the business day prior to the redemption date (any of the events described in the fourth and fifth bullets above, a "make-whole fundamental change").

On and after February 1, 2015 until the close of business on the business day immediately preceding the maturity date, holders may convert their 4.50% Convertible Notes, in multiples of $1,000 principal amount, at the option of the holder regardless of the foregoing circumstances.

Upon conversion, we will satisfy our conversion obligation by paying or delivering cash, shares of our common stock or a combination of cash and shares of our common stock, at our election. The conversion rate is initially 53.3333 shares of our common stock per $1,000 principal amount of 4.50% Convertible Notes (equivalent to a conversion price of approximately $18.75 per share of our common stock). The conversion rate is subject to adjustment in some events but will not be adjusted for accrued and unpaid interest. In addition, following any make-whole fundamental change that occurs prior to the maturity date, we will increase the conversion rate for a holder who elects to convert its 4.50% Convertible Notes in connection with such a make-whole fundamental change in certain circumstances. The increase in the conversion rate is determined based on a formula that takes into consideration our stock price at the time of the make-whole fundamental change (ranging from $15.00 to $100.00 per share) and the remaining time to maturity of the 4.50% Convertible Notes. The increase in the conversion rate declines from a high of 25.0% to 0.0% as the stock price at the time of the make-whole fundamental change increases from $15.00 and the remaining time to maturity of the 4.50% Convertible Notes decreases.

On or after November 1, 2012, and prior to the maturity date, we may redeem for cash all, but not less than all, of the 4.50% Convertible Notes if the last reported sales price of our common stock equals or exceeds 130% of the conversion price then in effect for 20 or more trading days in a period of 30 consecutive trading days ending on the trading day immediately prior to the date of the redemption notice. The redemption price will equal 100% of the principal amount of the 4.50% Convertible Notes to be redeemed plus any accrued and unpaid interest, including any additional interest, to, but excluding, the redemption date. To the extent a holder converts its 4.50% Convertible Notes in connection with our redemption notice, we will increase the conversion rate as described in the preceding paragraph.

The 4.50% Convertible Notes are senior, unsecured obligations of the Company and rank equally in right of payment with our unsecured debt and our existing 5.00% Convertible Notes, and are senior in right of payment to our debt that is expressly subordinated to the 4.50% Convertible Notes, if any. The 4.50% Convertible Notes are structurally subordinated to all debt and other liabilities and commitments of our subsidiaries, including our subsidiaries' guarantees of our indebtedness under our Senior Secured Notes, and are effectively junior to our secured debt to the extent of the assets securing such debt.

Senior Notes. On February 9, 2011, we successfully completed the issuance and sale of $200,000,000 aggregate principal amount of 11.375% Senior Notes due 2019 (the "Senior Notes"). In December 2011, 99% of the Senior Notes were converted to our Senior Secured Notes due 2017, which resulted in $1,970,000 of Senior Notes outstanding as of December 31, 2011. All covenants were terminated upon the conversion.

Senior Secured Notes due 2017. On December 19, 2011, the Company executed an Indenture among the Company, the guarantors party thereto and U.S. Bank National Association, as trustee. As a result, the Company issued $283,475,000 aggregate principal amount of Senior Secured Notes due 2017 ("Senior Secured Notes") pursuant to the indenture governing the Senior Secured Notes (the "Senior Secured Notes Indenture"). The Senior Secured Notes are fully and unconditionally guaranteed (the "Guarantees"), jointly and severally, on a senior secured basis by each of the Company's existing and future domestic restricted subsidiaries (the "Guarantors"). All of the Company's existing subsidiaries other than Endeavor Gathering, LLC are domestic restricted subsidiaries and Guarantors.

Under the terms of the Senior Secured Notes Indenture, interest on the Senior Secured Notes will:

- accrue from the date of issuance of the Senior Secured Notes or, if interest has already been paid, from the most recent interest payment date;

- unless the Company elects to pay a portion of the interest in the form of additional notes (a "PIK Election") with respect to an interest period, accrue for such interest period at the rate of 11.0% per annum, payable in cash, in arrears;

- if the Company makes a PIK Election with respect to an interest period, accrue for such interest period at the rate of 13.0% per annum in the aggregate, of which (i) 9.0% per annum shall be payable in cash, in arrears, and (ii) 4.0% per annum shall be payable in the form of additional notes (in minimum denominations of $1,000 and integral multiples thereof, with any fractional additional notes being paid in cash), in arrears;

- be payable on each June 1 and December 1, commencing June 1, 2012, to holders of record of the Senior Secured Notes as of the May 15 and November 15 immediately preceding the relevant interest payment date; and

- be computed on the basis of a 360-day year comprised of twelve 30-day months.

The Senior Secured Notes will mature on December 1, 2017 and will be secured by first-priority perfected liens on substantially all right, title and interest in or to substantially all of the assets and properties owned or acquired by the Company and the Guarantors (the "Collateral") The Collateral obligations are governed by, among other security documents, the Security Agreements.

The Senior Secured Notes are senior obligations of the Company and are secured by a first-priority perfected note lien on the Collateral (subject to certain permitted liens). The Senior Secured Notes rank senior in right of payment to all existing and future obligations of the Company that are expressly subordinated in right of payment to the Senior Secured Notes. The Senior Secured Notes rank pari passu to all unsubordinated obligations of the Company (though they will be effectively senior to any such obligations to the extent of the value of the collateral securing the obligations under the Senior Secured Notes). The Senior Secured Notes are effectively subordinated to all obligations of the Company that are subject to certain permitted liens (including, without limitation, certain letter of credit facilities and hedging obligations) ranking higher than the Senior Secured Notes to the extent of the value of the collateral securing such obligations or that are subject to a permitted lien that causes the assets subject to such lien to be excluded from the collateral. The Senior Secured Notes are also effectively subordinated to all obligations of any of Subsidiaries of the Company that do not guarantee the Senior Secured Notes.

The Senior Secured Notes Indenture restricts, among other things, the Company's and its restricted subsidiaries' ability to:

- incur or guarantee additional indebtedness or issue certain preferred stock;
- pay dividends or make other distributions;
- issue capital stock of our restricted subsidiaries;
- transfer or sell assets, including the capital stock of our restricted subsidiaries;
- make certain investments or acquisitions;
- grant liens on our assets;
- incur dividend or other payment restrictions affecting our restricted subsidiaries;
- enter into certain transactions with affiliates; and
- merge, consolidate or transfer all or substantially all of our assets.

The covenants are subject to important exceptions and qualifications.

If an event of default on the Senior Secured Notes has occurred and is continuing, the aggregate principal amount of the Senior Secured Notes, plus any accrued and unpaid interest and redemption premium, may be declared immediately due and payable at the trustee's discretion or upon request of at least 25% in principal amount of the outstanding Senior Secured Notes. These amounts automatically become due and payable upon the occurrence of certain bankruptcy events.

The Company may redeem any of the Senior Secured Notes, in whole or in part, at any time on or after December 1, 2014. Upon any such optional redemption, the Company will pay a redemption price equal to the following redemption prices (expressed as a percentage of principal amount of the Senior Secured Notes), plus accrued and unpaid interest on the Senior Secured Notes, if any, to, but not including, the applicable redemption date (subject to the right of holders of record on the relevant record date to receive interest due on the relevant interest payment date), if redeemed during the twelve-month period beginning on December 1 of the years indicated below:

Year	**Percentage**
2014	105.500 %
2015	102.750 %
2016 and thereafter	100.000 %

The Company will give not less than 30 nor more than 60 days notice of any such redemption.

At any time prior to December 1, 2014 the Company may, at its option, on any one or more occasions redeem up to 35% of the aggregate principal amount of the Senior Secured Notes (including Additional Notes but without duplication for exchange notes) originally issued under the Senior Secured Notes Indenture with the net cash proceeds of one or more equity offerings at a redemption price of 111.0% of the aggregate principal amount thereof, plus accrued and unpaid interest, if any, additional interest, if any, to, but not including, the redemption date (subject to the right of holders of record on the relevant record date to receive interest due on the relevant interest payment date); provided that (1) at least 65% of the original principal amount of the Senior Secured Notes originally issued under the Senior Secured Notes Indenture (including Additional Notes but without duplication for exchange notes) remains outstanding after each such redemption; and (2) the redemption occurs within 90 days after the closing of the related Equity Offering.

In addition, the Senior Secured Notes may be redeemed, in whole or in part, at any time prior to December 1, 2014 at the option of the Company upon not less than 30 nor more than 60 days' prior notice mailed by first-class mail to each holder of Notes at its registered address, at a redemption price equal to 100% of the principal amount of the Notes redeemed, plus an "Applicable Premium" as of, and accrued and unpaid interest to, but not including, the applicable redemption date (subject to the right of holders of record on the relevant record date to receive interest due on the relevant interest payment date).

If a Change of Control (as defined in the Senior Secured Notes Indenture) occurs, we must offer to repurchase the Senior Secured Notes at 101% of their principal amount, plus accrued and unpaid interest.

In addition, in connection with certain Asset Dispositions (as defined in the Senior Secured Notes Indenture), we must offer to repurchase the Senior Secured Notes with the proceeds of such Asset Dispositions within 30 days.

Share Lending Agreement

In February 2008, in connection with the offer and sale of the 5.00% Convertible Notes, we entered into a share lending agreement (the "Share Lending Agreement") with an affiliate of Jefferies & Company, Inc. (the "share borrower") and Jefferies & Company, Inc., as collateral agent for the Company. Under this agreement, we loaned to the share borrower up to the maximum number of shares of our common stock underlying the 5.00% Convertible Notes during a specified loan availability period. This maximum number of shares was initially 3,846,150 shares. We will receive a loan fee of $0.001 per share for each share of our common stock that we loan to the share borrower, payable at the time such shares are borrowed. The share borrower may borrow and re-borrow up to the maximum number of shares of our common stock during the loan availability period. In September 2011, 275,625 shares were returned to us. As of December 31, 2011, 2,364,375 shares of our common stock were subject to outstanding loans to the share borrower.

The share borrower's obligations under the Share Lending Agreement are unconditionally guaranteed by Jefferies Group, Inc., the ultimate parent company of the share borrower and Jefferies & Company, Inc. (the "guarantor"). If the guarantor receives a rating downgrade for its long term unsecured and unsubordinated debt below a specified level by both Standard & Poor's Ratings Services and Moody's Investors Service, Inc. (or any substitute rating agency mutually agreed upon by the Company and the share borrower), or by either of such rating agencies in certain circumstances, the share borrower has agreed to post and maintain with Jefferies & Company, Inc., acting as collateral agent for the Company, collateral in the form of cash, government securities, certificates of deposit, high-grade commercial paper of U.S. issuers, letters of credit or money market shares with a market value at least equal to 100% of the market value of the shares of our common stock borrowed by the share borrower as security for the share borrower's obligation to return the borrowed shares to the Company pursuant to the Share Lending Agreement.

The loan availability period under the Share Lending Agreement commenced on the date of the Share Lending Agreement and will continue until the date that any of the following occurs:

- we notify the share borrower in writing of our intention to terminate the Share Lending Agreement at any time after the entire principal amount of the 5.00% Convertible Notes ceases to be outstanding as a result of conversion, repurchase, at maturity or otherwise;
- we and the share borrower agree to terminate the Share Lending Agreement;
- we elect to terminate all of the outstanding loans upon a default by the share borrower under the Share Lending Agreement or by the guarantor under its guarantee, including a breach by the share borrower of any of its obligations or a breach in any material respect of any of the representations or covenants under the Share Lending Agreement or a breach by the guarantor of the guarantee, or the bankruptcy of the share borrower or the guarantor; or
- the share borrower elects to terminate all outstanding loans upon the bankruptcy of the Company.

Any shares we loan to the share borrower will be issued and outstanding for corporate law purposes, and accordingly, the holders of the borrowed shares will have all of the rights of a holder of a share of our outstanding common stock, including the right to vote the shares on all matters submitted to a vote of the Company's shareholders and the right to receive any dividends or other distributions that we may pay or make on our outstanding shares of common stock. However, under the Share Lending Agreement, the share borrower has agreed:

- not to vote any shares of the Company's common stock it has borrowed to the extent it owns such borrowed shares; and
- to pay to us an amount equal to any cash dividends that we pay on the borrowed shares.

Under U.S. generally accepted accounting principles currently in effect, the borrowed shares will not be considered outstanding for the purpose of computing and reporting our earnings per share.

Common and Preferred Stock Offerings

In February 2011, the Company completed an offering of 21,075,000 shares of its common stock at a price of $4.75 per share. The net proceeds to the Company were $93.6 million after discounts and underwriters' fees. In March 2011, the underwriters exercised the over-allotment option granted in connection with the February 2011 offering and purchased an additional 1,098,518 shares of common stock, which increased the net proceeds to the Company by $4.9 million after discounts and underwriters' fees. We used the net proceeds, together with proceeds from a concurrent private placement of the 11.375% Senior Notes, to fund an offer to purchase up to $50.0 million of our 5.00% convertible notes, repay the then outstanding balance under its secured revolving credit facility, fund the cash portion of the purchase price of the acquisitions described in "Item 1. Business," fund our exploration and development program and for other general corporate purposes.

In February 2011 and April 2011, we issued 2,268,971 and 3,542,091shares, respectively, of our common stock in connection with the Bakken acquisition described in Note A to our consolidated financial statements.

On December 19, 2011, the Company issued 3,877,254 shares of the Company's common stock pursuant to support agreements with each of the supporting holders in connection with the consummation of an exchange offer and consent solicitation for the Company's outstanding $200,000,000 11.375% Senior Notes, pursuant to which holders of 11.375% Senior Notes tendering in the exchange offer received new Senior Secured Notes.

During the year ended December 31, 2011, we received $25.8 million related to the issuance of 1,135,565 shares of its 9.25% Series B Cumulative Preferred Stock in ongoing at-the-market sales by the Company.

Working Capital

At December 31, 2011, we had working capital of $86.9 million.

Contractual Obligations

The following table reflects the Company's contractual obligations as of December 31, 2011:

	Payments Due by Period				
	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
			(in thousands)		
Long-term debt	$ 444,445	$ —	$ 72,750	$ 86,250	$ 285,445
Interest on long-term debt	202,969	38,925	70,878	64,106	29,060
Operating leases	5,069	1,632	1,838	1,504	95
Drilling contracts	14,903	13,797	1,106	—	—
Transportation agreements	46,852	6,190	12,323	11,336	17,003
Asset retirement obligations	7,726	360	644	31	6,691
75% PVOG financing(1)	1,294	26	95	37	1,136
Total	$ 723,258	$ 60,930	$ 159,634	$ 163,264	$ 339,430

(1) PVOG financing is payable out of 75% of revenues from the wells financed and repayment is based on estimated production which may vary from actual.

Other than obligations under the 5.00% Convertible Notes, the 4.50% Convertible Notes, the Senior Notes due 2019, the Senior Secured Notes, and the PVOG financing and operating leases, our commitments relate to capital expenditures for development of oil and natural gas properties. We will not enter into drilling or development commitments until such time as a source of funding for such commitments is known to be available, either through financing proceeds, internal cash flow or working capital.

Off-Balance Sheet Arrangements

We do not currently utilize any off-balance sheet arrangements to enhance our liquidity and capital resources position or for any other purpose.

Critical Accounting Policies

The preparation of the consolidated financial statements requires us to make a number of estimates and assumptions relating to the reported amounts of assets and liabilities and the disclosures of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the period. When alternatives exist among various accounting methods, the choice of accounting method can have a significant impact on reported amounts. The following is a discussion of our accounting estimates and judgments which management believes are most significant in its application of generally accepted accounting principles used in the preparation of the consolidated financial statements.

Full Cost Method of Accounting

The accounting for our business is subject to special accounting rules that are unique to the oil and natural gas industry. There are two allowable methods of accounting for oil and natural gas business activities: the successful efforts method and the full cost method. We follow the full cost method of accounting under which all costs associated with property acquisition, exploration and development activities are capitalized. We also capitalize internal costs that can be directly identified with our acquisition, exploration and development activities and do not include any costs related to production, general corporate overhead or similar activities. Under the successful efforts method, geological and geophysical costs and costs of carrying and retaining undeveloped properties are charged to expense as incurred. Costs of drilling exploratory wells that do not result in proved reserves are charged to expense. Depreciation, depletion, amortization and impairment of oil and natural gas properties are generally calculated on a well by well or lease or field basis versus the aggregated "full cost" pool basis. Depreciation, depletion and amortization of oil and gas properties ("DD&A") are provided using the units-of-production method based on estimates of proved oil and gas reserves and production, which are converted to a common unit of measure based upon their relative energy content. The Company's cost basis for depletion includes estimated future development costs to be incurred on proved undeveloped properties. Additionally, gain or loss is generally recognized on all sales of oil and natural gas properties under the successful efforts method. As a result, our financial statements will differ from companies that apply the successful efforts method since we will generally reflect a higher level of capitalized costs as well as a higher oil and natural gas depreciation, depletion and amortization rate, although this difference could change in periods of lower price environments that result in write-downs of our costs as described below.

The full cost method subjects companies to quarterly calculations of a "ceiling," or limitation on the amount of costs that can be capitalized on the balance sheet. If our capitalized costs are in excess of the calculated ceiling, the excess must be written off as an expense. Our discounted present value of estimated future net revenues (adjusted for cash flow hedges) from our proved oil and natural gas reserves is a major component of the ceiling calculation, and represents the component that requires the most subjective judgments. Estimates of reserves are forecasts based on engineering data, projected future rates of production and the timing of future expenditures. The process of estimating oil and natural gas reserves requires substantial judgment, resulting in imprecise determinations, particularly for new discoveries.

The passage of time provides more qualitative information regarding estimates of reserves, and revisions are made to prior estimates to reflect updated information. Annual performance revisions have occurred over the past years, which have both increased and decreased in individual years. There can be no assurance that more significant revisions will not be necessary in the future. If future significant revisions are necessary that reduce previously estimated reserve quantities, it could result in a write-down of our capitalized costs. In addition to the impact of the estimates of proved reserves on the calculation of the ceiling, estimates of proved reserves are also a significant component of the calculation of the full cost pool, depreciation, depletion and amortization.

The estimates of proved undeveloped reserve quantities and values are based on estimated future drilling which assumes that we will have the financing available to fund the estimated drilling costs. If we do not have such financing available at the time projected, the estimates of proved undeveloped reserve quantities and values will change.

While the quantities of proved reserves require substantial judgment, the associated prices of oil and natural gas reserves that are included in the discounted present value of the reserves do not require judgment. The ceiling calculation dictates that prices used in the determination of future net revenues represent the average of the first day of the month price for the 12-month period prior to the end of the quarterly period. Therefore, the future net revenues associated with the estimated proved reserves are not based on our assessment of future prices, but rather are based on prices in effect 12 months prior to each quarter when the ceiling calculation is performed. Such prices are utilized except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts, including the effects of derivatives qualifying as cash flow hedges. There were no cash flow hedges that impacted the ceiling test for 2011. Based on the average first-day-of-the-month prices for natural gas and oil during the 12-months of 2010 and 2009, cash flow hedges increased the full-cost ceiling by $52.3 million and $69.7 million as of December 31, 2010 and 2009, respectively, thereby reducing the ceiling test write-down by the same amount.

Because prices are held constant indefinitely, the resulting value is not indicative of the true fair value of the reserves. Oil and natural gas prices have historically been cyclical and can be either substantially higher or lower than various industry long-term price forecasts. Therefore, oil and natural gas property write-downs that result from applying the full cost ceiling limitation rules, and that are caused by fluctuations in price as opposed to reductions in the underlying quantities of reserves, should not be viewed as absolute indicators of a reduction of the ultimate value of the related reserves.

Capitalized costs are amortized on a composite unit-of-production method based on proved oil and natural gas reserves.

Depreciation, depletion and amortization expense is also based on the amount of estimated reserves. If we maintain the same level of production year over year, the depreciation, depletion and amortization expense may be significantly different if our estimate of remaining reserves changes significantly.

Because of the volatile nature of crude oil and natural gas prices, it is not possible to predict the timing or magnitude of full cost writedowns.

Asset Retirement Obligations

Our asset retirement obligations ("ARO") consist primarily of estimated costs of dismantlement, removal, site reclamation and similar activities associated with our oil and natural gas properties. We recognize the discounted fair value of a liability for an ARO in the period in which it is incurred with the associated asset retirement cost capitalized as part of the carrying cost of the oil and natural gas asset. The recognition of an ARO requires that management make numerous estimates, assumptions and judgments regarding such factors as the existence of a legal obligation for an ARO; estimated probabilities, amounts and timing of settlements; the credit-adjusted risk-free rate to be used; inflation rates; and future advances in technology. In periods subsequent to initial measurement of the ARO, the Company must recognize period-to-period changes in the liability resulting from the passage of time and revisions to either the timing or the amount of the original estimate of undiscounted cash flows. The related accretion of the liability is charged as an expense on the consolidated statement of operations.

Income Taxes

As part of the process of preparing the consolidated financial statements, we are required to estimate the federal and state income taxes in each of the jurisdictions in which we operate. This process involves estimating the actual current tax exposure together with assessing temporary differences resulting from differing treatment of items, such as derivative instruments, depreciation, depletion and amortization, and certain accrued liabilities for tax and accounting purposes. These differences and the net operating loss carryforwards result in deferred tax assets and liabilities, which are included in our consolidated balance sheet. We must then assess, using all available positive and negative evidence, the likelihood that it is more likely than not that the deferred tax assets will be recovered from future taxable income. If we believe that it is reasonable that the deferred tax assets will not be recovered in the future, we must establish a valuation allowance. Generally, to the extent we establish a valuation allowance or increase or decrease this allowance in a period, we must include an expense or reduction of expense within the tax provisions in the consolidated statement of operations.

Derivative Instruments

We recognize derivative instruments at fair value. Upon entering into a derivative contract, we may designate the derivative as either a fair value hedge or a cash flow hedge, or decide that the contract is not a hedge, and thenceforth, mark the contract to market through earnings. We document the relationship between the derivative instrument designated as a hedge and the hedged items, as well as our objective for risk management and strategy for use of the hedging instrument to manage the risk. Derivative instruments designated as cash flow hedges are linked to specific forecasted transactions. We assess at inception, and on an ongoing basis, whether a derivative instrument used as a hedge is highly effective in offsetting changes in the fair value or cash flows of the hedged item. A derivative that is not a highly effective hedge does not qualify for hedge accounting.

Changes in fair value of a qualifying cash flow hedge are recorded in accumulated other comprehensive income, until earnings are affected by the cash flows of the hedged item. When the cash flow of the hedged item is recognized in the statement of operations, the fair value of the associated cash flow hedge is reclassified from accumulated other comprehensive income into earnings as a component of oil and gas sales. Ineffective portions of a cash flow hedge are recognized currently as a component of oil and gas sales. The changes in fair value of derivative instruments not qualifying or not designated as hedges are reported currently in the consolidated statement of operations as gains (losses) on derivatives, a component of non-operating income (expense). If a derivative instrument no longer qualifies as a cash flow hedge, hedge accounting is discontinued and the gain or loss that was recorded in accumulated other comprehensive income is recognized over the period anticipated in the original hedge transaction.

Oil and Gas Revenues

Oil and natural gas revenues are recognized when sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred, and if collectability of the revenue is probable. Delivery occurs and title is transferred when production has been delivered to a purchaser's pipeline or truck. As a result of the numerous requirements necessary to gather information from purchasers or various measurement locations, calculate volumes produced, perform field and wellhead allocations and distribute and disburse funds to various working interest partners and royalty owners, the collection of revenues from oil and gas production may take up to 60 days following the month of production. Therefore, we make accruals for revenues and accounts receivable based on estimates of our share of production, particularly from properties that are operated by others. Since the settlement process may take 30 to 60 days following the month of actual production, our financial results include estimates of production and revenues for the related time period. We record any differences, which we do not expect to be significant, between the actual amounts ultimately received and the original estimates in the period they become finalized.

During the course of normal operations, the Company and other joint interest owners of natural gas reservoirs will take more or less than their respective ownership share of the natural gas volumes produced. These volumetric imbalances are monitored over the lives of the wells' production capability. If an imbalance exists at the time the wells' reserves are depleted, cash settlements are made among the joint interest owners under a variety of arrangements. The Company follows the sales method of accounting for gas imbalances. A liability is recorded when the Company's excess takes of natural gas volumes exceed its estimated remaining recoverable reserves. No receivables are recorded for those wells where the Company has taken less than its ownership share of gas production. There are no significant imbalances as of December 31, 2011, 2010 or 2009.

Other

See Note A—Nature of Operations and Summary of Significant Accounting Policies, to the Consolidated Financial Statements for information related to other accounting and reporting policies.

Recently Issued Accounting Pronouncements

See Note A—Nature of Operations and Summary of Significant Accounting Policies, to the Consolidated Financial Statements for a discussion of recently issued accounting pronouncements.

Price Risk Management

See Item 7A—Quantitative and Qualitative Disclosures About Market Risk.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

Commodity Price Risk

We are subject to price fluctuations of natural gas and crude oil. Prices received for natural gas and crude oil sold on the spot market are volatile due to factors beyond our control. Reductions in crude oil and natural gas prices could have a material adverse effect on our financial position, results of operations, capital expenditures and quantities of reserves recoverable on an economic basis. Any reduction in reserves, including reductions due to lower prices, can adversely affect our liquidity and our ability to obtain capital for our acquisition and development activities.

To mitigate a portion of our exposure to fluctuations in commodity prices, we enter into financial price risk management activities with respect to a portion of projected crude oil and natural gas production through financial price commodity swaps, collars and put spreads. We monetized our natural gas hedges in December 2011, which provided to us approximately $18.5 million in net cash proceeds excluding fees and commissions.

We had no oil or natural gas derivative contracts in place as of December 31, 2011.

Interest Rate Risk

We terminated our revolving bank credit facility during December 2011, and currently have no indebtedness for borrowed money based on a floating interest rate.

Our $73 million of 5.00% Convertible Notes, $86 million of 4.50% Convertible Notes, $1.9 million of Senior Notes have fixed interest rates, and our $283.5 million of Senior Secured Notes have an interest rate fixed at either 11.0% per annum or the effective rate applicable to a PIK Election.

Item 8. Financial Statements and Supplementary Data.

Our consolidated financial statements are presented beginning on page F-1 found at the end of this report.

Item 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure.

None.

Item 9A. Controls and Procedures.

Controls and Procedures

Our principal executive officer and principal financial officer have reviewed and evaluated the effectiveness of our disclosure controls and procedures (as defined in Exchange Act Rule 13a-15(e)) as of December 31, 2011. Disclosure controls and procedures include, without limitation, controls and procedures designed to provide us with reasonable assurance that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms and is accumulated and communicated to our management, including our principal executive officer and principal financial officer, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosures. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Our disclosure controls and procedures are designed to provide us with reasonable assurance of achieving their objective. Based on that evaluation and what is described below in *Management's Annual Report on Internal Control over Financial Reporting*, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures were effective as of December 31, 2011.

Changes in Internal Control Over Financial Reporting

During the fourth quarter of 2011, no change occurred in our internal control over financial reporting that materially affected, or is likely to materially affect, our internal control over financial reporting.

Management's Annual Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Exchange Act Rules 13a-15(f) and 15d-15(f). Our system of internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Our internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorizations of our management and directors; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of our assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In order to evaluate the effectiveness of internal control over financial reporting, as required by Section 404 of the Sarbanes-Oxley Act, our management, including our principal executive officer and principal financial officer, conducted an assessment, including testing, using the criteria in *Internal Control—Integrated Framework,* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO").

Based on our evaluation under the framework in Internal Control – Integrated Framework, we have concluded that our internal control over financial reporting was effective as of December 31, 2011.

Grant Thornton LLP, our independent registered public accounting firm, audited the Company's internal control over financial reporting and, based on that audit, issued their report that follows.

/s/ Ken L. Kenworthy, Jr.

Ken L. Kenworthy, Jr.
Chief Executive Officer

/s/ James A. Merrill

James A. Merrill
Chief Financial Officer

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Shareholders
GMX Resources Inc.

We have audited GMX Resources Inc. (a Oklahoma Corporation) and subsidiaries' (collectively, the "Company") internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, GMX Resources Inc. and subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control-Integrated Framework* issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of GMX Resources Inc. and subsidiaries as of December 31, 2011 and 2010, and the related consolidated statements of operations, comprehensive income (loss), changes in equity and cash flows for each of the three years in the period ended December 31, 2011 and our report dated March 9, 2012 expressed an unqualified opinion.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
March 9, 2012

Certifications

Our chief executive and chief financial officers have completed the certifications required to be filed as an Exhibit to this Report (See Exhibits 31.1 and 31.2) relating to the design of our disclosure controls and procedures and the design of our internal control over financial reporting.

Item 9B. Other Information.

None.

PART III

In accordance with the provisions of General Instruction G(3), the information required by Items 10 through 14 of Part III of this Form 10-K is incorporated herein by reference to the Company's definitive Proxy Statement for the 2012 Annual Meeting of Shareholders to be filed by the Company pursuant to Regulation 14A of the General Rules and Regulation under the Exchange Act prior to April 30, 2012.

Code of Business Conduct and Ethical Practices

We have adopted a Code of Business Conduct and Ethics. The Code of Business Conduct and Ethics is applicable to all employees and directors, including our principal executive officer, principal financial officer, principal accounting officer and persons performing similar functions. The Company has also adopted Corporate Governance Guidelines that apply to all directors. A copy of the Code of Business Conduct and Ethics and the Corporate Governance Guidelines, as well as the charters for the Audit, Compensation and Nominating/Corporate Governance Committees, are available under "Corporate Governance" at the Company's web site, *www.gmxresources.com.* Copies of the Code of Business Conduct and Ethics may also be obtained free of charge on our website or by requesting a copy in writing from our Corporate Secretary at 9400 North Broadway, Suite 600, Oklahoma City, Oklahoma 73114. Any waivers of the Code of Business Conduct and Ethics must be approved by our board of directors (or a designated board committee). The Company intends to disclose amendments to, or waivers from, its Code of Business Conduct and Ethics and its Corporate Governance Guidelines by posting to its web site noted above.

PART IV

Item 15. Exhibits and Financial Statement Schedules.

The following documents are filed as part of this report.

Financial Statements: See Index to Consolidated Financial Statements and Consolidated Financial Statement Schedule set forth on page F-1 of this report.

Exhibits: For a list of documents filed as exhibits to this report, see the Exhibit Index immediately preceding the Exhibits filed with this report.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

GMX RESOURCES INC.

Dated: March 9, 2012

By: /s/ JAMES A. MERRILL
James A. Merrill, Chief Financial Officer

Pursuant to the requirement of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signatures	Title	Date
/s/ KEN L. KENWORTHY, JR. Ken L. Kenworthy, Jr.	Chief Executive Officer and Director (Principal Executive Officer)	March 9, 2012
/s/ JAMES A. MERRILL James A. Merrill	Chief Financial Officer (Principal Financial and Accounting Officer)	March 9, 2012
/s/ T. J. BOISMIER T. J. Boismier	Director	March 9, 2012
/s/ STEVEN CRAIG Steven Craig	Director	March 9, 2012
/s/ KEN L. KENWORTHY, SR. Ken L. Kenworthy, Sr.	Director	March 9, 2012
/s/ JON W. MCHUGH Jon W. McHugh	Director	March 9, 2012
/s/ MICHAEL G. COOK Michael G. Cook	Director	March 9, 2012
/s/ THOMAS G. CASSO Thomas G. Casso	Director	March 9, 2012
/s/ J.David Lucke J. David Lucke	Director	March 9, 2012
/s/ Michael Rohleder Michael Rohleder	Director	March 9, 2012

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Shareholders
GMX Resources Inc.

We have audited the accompanying consolidated balance sheets of GMX Resources Inc. (an Oklahoma corporation) and subsidiaries (collectively, the "Company") as of December 31, 2011 and 2010, and the related consolidated statements of operations, comprehensive income (loss), changes in equity and cash flows for each of the three years in the period ended December 31, 2011. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of GMX Resources Inc. and subsidiaries as of December 31, 2011 and 2010, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2011, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note A to the consolidated financial statements, the Company changed its method of estimating oil and gas reserves and related disclosures in 2009.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) and our report dated March 9, 2012 expressed an unqualified opinion.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
March 9, 2012

GMX Resources Inc. and Subsidiaries
Consolidated Balance Sheets
(dollars in thousands, except share data)

	December 31, 2011	December 31, 2010
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 102,493	$ 2,357
Restricted cash	4,325	—
Accounts receivable—interest owners	8,607	5,339
Accounts receivable—oil and natural gas revenues, net	7,082	6,829
Derivative instruments	—	19,486
Inventories	326	326
Prepaid expenses and deposits	2,655	5,767
Assets held for sale	2,045	26,618
Total current assets	127,533	66,722
OIL AND NATURAL GAS PROPERTIES, BASED ON THE FULL COST METHOD		
Properties being amortized	1,062,801	938,701
Properties not subject to amortization	147,224	39,694
Less accumulated depreciation, depletion, and impairment	(871,346)	(630,632)
	338,679	347,763
PROPERTY AND EQUIPMENT, AT COST, NET	65,858	69,037
DERIVATIVE INSTRUMENTS	—	17,484
OTHER ASSETS	10,131	6,084
TOTAL ASSETS	$ 542,201	$ 507,090
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 13,550	$ 24,919
Accrued expenses	17,835	33,048
Accrued interest	3,256	3,317
Revenue distributions payable	5,980	4,839
Current maturities of long-term debt	26	26
Total current liabilities	40,647	66,149
LONG-TERM DEBT, LESS CURRENT MATURITIES	426,805	284,943
DEFERRED PREMIUMS ON DERIVATIVE INSTRUMENTS	—	10,622
OTHER LIABILITIES	7,476	7,157
COMMITMENTS AND CONTINGENCIES—SEE NOTE I		
EQUITY:		
Preferred stock, par value $.001 per share, 10,000,000 shares authorized:		
Series A Junior Participating Preferred Stock—25,000 shares authorized, none issued and outstanding	—	—
9.25% Series B Cumulative Preferred Stock— 6,000,000 Shares authorized, 3,176,734 and 2,041,169 shares issued and outstanding as of 2011 and 2010, respectively, (aggregate liquidation preference $79,418 and $51,029 as of December 31, 2011 and 2010, respectively)	3	2
Common stock, par value $.001 per share—100,000,000 shares authorized, 63,085,432 issued and outstanding in 2011 and 31,283,353 shares in 2010	63	31
Additional paid-in capital	690,986	531,944
Accumulated deficit	(649,341)	(430,784)
Accumulated other comprehensive income, net of taxes	14,029	15,227
Total GMX equity	55,740	116,420
Noncontrolling interest	11,533	21,799
Total equity	67,273	138,219
TOTAL LIABILITIES AND EQUITY	$ 542,201	$ 507,090

See accompanying notes to consolidated financial statements.

GMX Resources Inc. and Subsidiaries
Consolidated Statements of Operations
(dollars in thousands, except share and per share data)

	Year Ended December 31, 2011	2010	2009
OIL AND GAS SALES, net of gain or (loss) from ineffectiveness of derivatives of $114, $(1,280) and $1,018, respectively	$ 116,741	$ 96,523	$ 94,294
EXPENSES:			
Lease operations	13,420	10,651	11,776
Production and severance taxes	1,196	743	(930)
Depreciation, depletion, and amortization	50,270	38,061	31,006
Impairment of oil and natural gas properties and assets held for sale	205,754	143,712	188,150
General and administrative	28,863	27,119	21,390
Total expenses	299,503	220,286	251,392
Loss from operations	(182,762)	(123,763)	(157,098)
NON-OPERATING INCOME (EXPENSES):			
Interest expense	(31,875)	(18,642)	(16,748)
Gain (loss) on extinguishment of debt	4,987	—	(4,976)
Interest and other income (expense)	205	(4)	72
Gain (loss) on derivatives	3,612	(122)	(2,370)
Total non-operating expenses	(23,071)	(18,768)	(24,022)
Loss before income taxes	(205,833)	(142,531)	(181,120)
INCOME TAXES BENEFIT (PROVISION)	(615)	4,239	33
NET LOSS	(206,448)	(138,292)	(181,087)
Net income attributable to noncontrolling interest	5,389	3,114	173
NET LOSS APPLICABLE TO GMX	(211,837)	(141,406)	(181,260)
Preferred stock dividends	6,720	4,633	4,625
NET LOSS APPLICABLE TO COMMON SHAREHOLDERS	$ (218,557)	$ (146,039)	$ (185,885)
LOSS PER SHARE—Basic	$ (4.12)	$ (5.18)	$ (9.20)
LOSS PER SHARE—Diluted	$ (4.12)	$ (5.18)	$ (9.20)
WEIGHTED AVERAGE COMMON SHARES—Basic	53,071,200	28,206,506	20,210,400
WEIGHTED AVERAGE COMMON SHARES—Diluted	53,071,200	28,206,506	20,210,400

See accompanying notes to consolidated financial statements.

GMX Resources Inc. and Subsidiaries
Consolidated Statements of Comprehensive Income (Loss)
(dollars in thousands)

	Years Ended December 31,		
	2011	**2010**	**2009**
Net loss	$ (206,448)	$ (138,292)	$ (181,087)
Other comprehensive income (loss), net of income tax:			
Change in fair value of derivative instruments, net of income taxes of $5,754, $11,512 and $6,961, respectively	11,170	22,346	13,513
Reclassification of (gain) loss on settled contracts, net of income taxes of ($6,372), ($8,019) and $(10,489), respectively	(12,368)	(15,566)	(20,362)
Comprehensive loss	(207,646)	(131,512)	(187,936)
Comprehensive income attributable to the noncontrolling interest	5,389	3,114	173
Comprehensive loss attributable to GMX shareholders	$ (213,035)	$ (134,626)	$ (188,109)

See accompanying notes to consolidated financial statements.

GMX Resources Inc. and Subsidiaries
Consolidated Statement of Changes in Equity
Year Ended December 31, 2009, 2010 and 2011
(dollars and shares in thousands)

	Preferred shares	Common shares	Preferred par value	Common par value	Additional paid-in capital	Retained earnings (accumulated deficit)	Accumulated other comprehensive income	Total GMX Resources equity	Non-controlling interest	Total equity
BALANCE AT DECEMBER 31, 2008	2,000	18,795	$ 2	$ 19	$ 330,340	$ (98,860)	$ 15,296	$ 246,797	$ —	$ 246,797
Stock Options Exercised	—	1	—	—	5	—	—	5	—	5
Restricted Stock Awards	—	19	—	—	—	—	—	—	—	—
Stock Compensation	—	—	—	—	5,844	—	—	5,844	—	5,844
Preferred Stock Dividends	—	—	—	—	—	(4,625)	—	(4,625)	—	(4,625)
Shares Issued	—	12,700	—	13	164,051	—	—	164,064	—	164,064
Shares Pursuant to Share Lending Agreement	—	(300)	—	(1)	—	—	—	(1)	—	(1)
Convertible Debt Issued	—	—	—	—	8,421	—	—	8,421	—	8,421
Sale of Subsidiary Membership Interest to Noncontrolling Interest	—	—	—	—	13,984	—	—	13,984	21,908	35,892
Net Loss	—	—	—	—	—	(181,260)	—	(181,260)	173	(181,087)
Other Comprehensive Income	—	—	—	—	—	—	(6,849)	(6,849)	—	(6,849)
December 31, 2009	2,000	31,215	$ 2	$ 31	$ 522,645	$ (284,745)	$ 8,447	$ 246,380	$ 22,081	$ 268,461
Restricted Stock Awards	—	188	—	—	—	—	—	—	—	—
Stock Compensation	—	—	—	—	6,274	—	—	6,274	—	6,274
Preferred Stock Dividends	—	—	—	—	—	(4,633)	—	(4,633)	—	(4,633)
Shares Issued	41	380	—	—	3,025	—	—	3,025	—	3,025
Shares Pursuant to Share Lending Agreement	—	(500)	—	—	—	—	—	—	—	—
Net Loss	—	—	—	—	—	(141,406)	—	(141,406)	3,114	(138,292)
Contributions—Non-Controlling Interest	—	—	—	—	—	—	—	—	1,244	1,244
Distributions—Non-Controlling Interest	—	—	—	—	—	—	—	—	(4,640)	(4,640)
Other Comprehensive Loss	—	—	—	—	—	—	6,780	6,780	—	6,780
December 31, 2010	2,041	31,283	$ 2	$ 31	$ 531,944	$ (430,784)	$ 15,227	$ 116,420	$ 21,799	$ 138,219
Preferred Stock Dividends	—	—	—	—	—	(6,720)	—	(6,720)	—	(6,720)
Stock Compensation	—	216	—	—	4,248	—	—	4,248	—	4,248
Shares Pursuant to Share Lending Agreement	—	(276)	—	—	—	—	—	—	—	—
Shares Issued	1,136	31,862	1	32	160,057	—	—	160,090	—	160,090
Retirement of Convertible Debt	—	—	—	—	(5,263)	—	—	(5,263)	—	(5,263)
Net Loss	—	—	—	—	—	(211,837)	—	(211,837)	5,389	(206,448)
Contributions—Non-Controlling Interest	—	—	—	—	—	—	—	—	422	422
Distributions—Non-Controlling Interest	—	—	—	—	—	—	—	—	(16,077)	(16,077)
Other Comprehensive Income	—	—	—	—	—	—	(1,198)	(1,198)	—	(1,198)
BALANCE AT DECEMBER 31, 2011	3,177	63,085	$ 3	$ 63	$ 690,986	$ (649,341)	$ 14,029	$ 55,740	$ 11,533	$ 67,273

See accompanying notes to consolidated financial statements.

GMX Resources Inc. and Subsidiaries
Consolidated Statements of Cash Flows
(dollars in thousands)

	Year Ended December 31, 2011	2010	2009
CASH FLOWS DUE TO OPERATING ACTIVITIES			
Net loss	$ (206,448)	$ (138,292)	$ (181,087)
Adjustments to reconcile net loss to net cash provided by operating activities:			
Depreciation, depletion, and amortization	50,270	38,061	31,006
Impairment and other writedowns	205,754	143,712	188,150
Deferred income taxes	615	(4,209)	—
Non-cash stock compensation expense	3,677	5,450	4,635
Loss (gain) on extinguishment of debt	(4,987)	(141)	4,976
Non-cash interest expense	9,378	9,330	6,036
Other	(4,918)	1,402	1,838
Decrease (increase) in:			
Accounts receivable	(3,521)	(1,595)	(1,338)
Prepaid expenses and other assets	(301)	(1,730)	(457)
Increase (decrease) in:			
Accounts payable and accrued expenses	122	6,680	(2,852)
Revenue distributions payable	952	67	(1,417)
Net cash provided by operating activities	50,593	58,735	49,490
CASH FLOWS DUE TO INVESTING ACTIVITIES			
Purchase, exploration and development of oil and natural gas properties	(269,567)	(172,726)	(162,076)
Proceeds from sales of oil and natural gas properties, property, equipment and assets held for sale	15,821	7,010	—
Sale of volumetric production payment	49,700	—	—
Cash settlement of hedges	21,213	—	—
Purchase of property and equipment	(2,411)	(10,284)	(19,248)
Other investing	(4,325)	—	—
Net cash used in investing activities	(189,569)	(176,000)	(181,324)
CASH FLOWS DUE TO FINANCING ACTIVITIES			
Borrowings on revolving bank credit facility	70,500	92,000	99,000
Repayments of revolving bank credit facility	(162,500)	—	(179,000)
Proceeds from issuance of long-term debt	293,666	—	86,250
Repayment of long-term debt	(47,124)	(79)	(34,669)
Proceeds from sale of common stock	105,324	—	164,069
Proceeds from sale of preferred stock	25,809	949	—
Dividends paid on Series B cumulative preferred stock	(6,720)	(4,633)	(4,625)
Fees paid related to financing activities	(24,188)	(773)	(7,085)
Contributions from non-controlling interest member	422	1,244	—
Distributions to non-controlling interest member	(16,077)	(4,640)	—
Sale of equity interest of a business	—	—	36,000
Other	—	—	732
Net cash provided by financing activities	239,112	84,068	160,672
NET INCREASE (DECREASE) IN CASH	100,136	(33,197)	28,838
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	2,357	35,554	6,716
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 102,493	$ 2,357	$ 35,554

See accompanying notes to consolidated financial statements.

NOTE A—NATURE OF OPERATIONS AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

NATURE OF BUSINESS AND PRINCIPLES OF CONSOLIDATION

GMX Resources Inc. and its subsidiaries (collectively, "GMX" the "Company", "we," "us" and "our") is an independent oil and natural gas exploration and production company with a portfolio of leasehold acreage in multiple resource plays that allow us flexibility to deploy capital based on a variety of economic and technical factors, including commodity prices (including differentials applicable to the basin) well costs, service availability, and take-away capacity.

Prior to 2011, the Company focused on the development of the hydrocarbon formations in East Texas including the Cotton Valley Sands ("CVS") layer in the Schuler formation and the Upper, Middle and Haynesville/Lower Bossier layers of the Bossier formation (the "Haynesville/Bossier Shale", or "H/B"), in the Sabine Uplift of the Carthage, North Field primarily located in Harrison and Panola counties of East Texas (previously designated as our "primary development area").

In late 2010, we made a strategic decision to expand our asset base and development activities into other basins in order to diversify our significant concentration in natural gas to a multiple basin and commodity strategy with more liquid hydrocarbon opportunities. In the first half of 2011, we acquired core positions in over 75,000 undeveloped net acres in two of the leading oil resource plays in the U.S.; the Williston Basin of North Dakota/Montana, targeting the Bakken/ Three Forks Formation, and in the oil window of the Denver Julesburg Basin (the "DJ Basin") of Wyoming, targeting the emerging Niobrara Formation. We believe the flexibility with the acquisition of the liquids-rich (estimated 90% oil) Bakken and Niobrara acreage will enable us to generate higher cash flow growth to fund our capital expenditure program. The Company is leveraging our expertise in H/B Shale horizontal drilling to successfully develop these newly acquired oil resource plays. A summary of the 2011 transactions are as follows:

- *Bakken acquisitions*-During the first half of 2011, we acquired all of the working interest and an average greater than 80% net revenue interest in approximately 35,000 undeveloped net acres of oil and gas leases located in Billings, Stark, McKenzie and Dunn Counties of North Dakota, and Richland, Sheridan and Wibaux Counties of Montana. We hold Williston Basin leases in approximately 150 1,280-acre units and expect to be the operator in approximately 43 of those units, providing a minimum of 172 operated locations.

- *Niobrara acquisitions*-During the first half of 2011, we acquired all of the working interest and an 80% net revenue interest in approximately 40,000 undeveloped net acres of oil and gas leases located in Platte, Goshen and Laramie Counties of Wyoming. We hold DJ Basin leases in approximately 146 640-acre units and expect to be the operator in approximately 95 of those units, providing a minimum of 380 operated locations.

We have three subsidiaries: Diamond Blue Drilling Co. ("Diamond Blue"), Endeavor Pipeline Inc. ("Endeavor Pipeline"), which operates our water supply and salt water disposal systems in our East Texas area, and Endeavor Gathering, LLC ("Endeavor Gathering"), which owns the natural gas gathering system and related equipment operated by Endeavor Pipeline. Kinder Morgan Endeavor LLC ("KME") owns a 40% membership interest in Endeavor Gathering.

The accompanying consolidated financial statements have been prepared in conformity with accounting principles generally accepted in the United States ("GAAP"). References to GAAP issued by the Financial Accounting Standards Board ("FASB") in these footnotes are to the FASB Accounting Standards Codification ("ASC"). The consolidated financial statements include the accounts of GMX and its wholly and majority owned subsidiaries. All significant intercompany transactions have been eliminated.

USE OF ESTIMATES: The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of oil and gas reserves, assets and liabilities, 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. Actual results could differ from those estimates. Significant estimates include estimates for proved oil and natural gas reserve quantities, deferred income taxes, asset retirement obligations, fair value of derivative instruments, useful lives of property and equipment, expected volatility and contract term to exercise outstanding stock options, and are subject to change.

RECLASSIFICATIONS: Certain reclassifications in the Consolidated Statements of Cash Flows have been made to prior years amounts to conform to current year presentations.

CASH, CASH EQUIVALENTS AND RESTRICTED CASH: The Company considers all highly liquid investments with maturities of three months or less at the time of purchase to be cash equivalents. The carrying value of cash and cash equivalents approximates fair value due to the short-term nature of these instruments.

The Company had $4.3 million in restricted cash related to undrawn letters of credit as of December 31, 2011. There was no restricted cash as of December 31, 2010.

CONCENTRATIONS OF CREDIT RISK: Substantially all of the Company's receivables are within the oil and gas industry, primarily from purchasers of natural gas and crude oil and from partners with interests in common properties operated by the Company. Although diversified among many companies, collectability is dependent upon the financial wherewithal of each individual company as well as the general economic conditions of the industry. The receivables are not collateralized; however the Company does review these parties for creditworthiness and general financial condition.

The Company has accounts with separate banks in Louisiana and Oklahoma. At December 31, 2011 and 2010, the Company had $99.6 million and $4.5 million, respectively, invested in overnight investment sweep accounts. Bank deposit accounts may, at times, exceed federally insured limits. The Company has not experienced any losses in such accounts and does not believe it is exposed to significant credit risk on its cash.

The Company uses natural gas and crude oil commodity derivatives to hedge a portion of its exposure to natural gas and crude oil price volatility. These arrangements expose the Company to credit risk from its counterparties. To mitigate that risk, the Company only uses counterparties that are highly-rated entities with corporate credit ratings at or exceeding A or Aa as classified by Standard & Poor's and Moody's, respectively.

Sales to individual customers constituting 10% or more of total natural gas and crude oil sales were as follows for each of the years ended December 31:

	2011	2010	2009
Natural gas			
Texla Energy Management, Inc.	48%	44%	54%
Southwest Energy, L.P.	15%	—	—
ConocoPhillips Company	10%	—	—
Tenaska	—	16%	—
Various purchasers through Penn Virginia Oil & Gas, L.P.	—	14%	21%
Louis Dreyfus	—	10%	—
BP Energy Company	—	—	12%
Waskom Gas Processing Company	—	—	11%
Crude oil			
Sunoco, Inc	62%	61%	52%
Various purchasers through Penn Virginia Oil & Gas, L.P.	30%	39%	43%

If the Company were to lose a purchaser, it believes it could replace it with a substitute purchaser with substantially equivalent terms.

INVENTORIES: Inventories consist of crude oil in tanks and natural gas liquids. Treated and stored crude oil inventory and natural gas liquids at the end of the year are valued at the lower of production cost or market.

ACCOUNTS RECEIVABLE: The Company has receivables from joint interest owners and oil and gas purchasers that are generally uncollateralized. The Company reviews these parties for creditworthiness and general financial condition. Accounts receivable are generally due within 30 days and accounts outstanding longer than 60 days are considered past due. If necessary, the Company would determine an allowance by considering the length of time past due, previous loss history, future net revenues of the debtor's ownership interest in oil and gas properties operated by the Company and the owners ability to pay its obligation, among other things. The Company writes off accounts receivable when they are determined to be uncollectible.

The Company establishes provisions for losses on accounts receivable if it determines that it will not collect all or part of the outstanding balance. The Company regularly reviews collectability and establishes or adjusts the allowance as necessary using the specific identification method. There was no allowance for doubtful accounts at December 31, 2011 and 2010.

OIL AND NATURAL GAS PROPERTIES: The Company follows the full cost method of accounting for its oil and natural gas properties and activities. Accordingly, the Company capitalizes all costs incurred in connection with the acquisition, exploration and development of oil and natural gas properties. The Company capitalizes internal costs that can be directly identified with exploration and development activities, but does not include any costs related to production, general corporate overhead, or similar activities. Capitalized costs include geological and geophysical work, 3D seismic, delay rentals, drilling and completing and equipping oil and gas wells, including salaries and benefits and other internal costs directly attributable to these activities. Also included in oil and natural gas properties are tubular and other lease and well equipment of $3.8 million and $4.1 million at December 31, 2011 and 2010, respectively, that have not been placed in service but for which we plan to utilize in our on-going exploration and development activities.

Proceeds from dispositions of oil and gas properties are accounted for as a reduction of capitalized costs, with no gain or loss generally recognized upon disposal of oil and natural gas properties unless such disposal significantly alters the relationship between capitalized costs and proved reserves. Revenues from services provided to working interest owners of properties in which GMX also owns an interest, to the extent they exceed related costs incurred, are accounted for as reductions of capitalized costs of oil and natural gas properties.

Investments in unevaluated properties and major development projects are not amortized until proved reserves associated with the projects can be determined or until impairment occurs. The balance of unevaluated properties is comprised of capital costs incurred for undeveloped acreage, exploratory wells in progress and capitalized interest costs. We assess all items classified as unevaluated property on a quarterly basis for possible impairment or reduction in value. We assess our properties on an individual basis or as a group if properties are individually insignificant. Our assessment includes consideration of the following factors, among others: intent to drill; remaining lease term; geological and geophysical evaluations; drilling results and activity; the assignment of proved reserves; and the economic viability of development if proved reserves are assigned. During any period in which these factors indicate an impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full-cost pool and are then subject to amortization.

Depreciation, depletion and amortization of oil and gas properties ("DD&A") are provided using the units-of-production method based on estimates of proved oil and gas reserves and production, which are converted to a common unit of measure based upon their relative energy content. The Company's cost basis for depletion includes estimated future development costs to be incurred on proved undeveloped properties. The computation of DD&A takes into consideration restoration, dismantlement, and abandonment costs and the anticipated proceeds from salvaging equipment. DD&A expense for oil and natural gas properties was $44.3 million, $32.9 million and $23.9 million for the years ended December 31, 2011, 2010 and 2009, respectively.

Capitalized costs are subject to a "ceiling test," which limits the net book value of oil and natural gas properties less related deferred income taxes to the estimated after-tax future net revenues discounted at a 10-percent interest rate. The cost of unproved properties is added to the future net revenues less income tax effects. At December 31, 2011 and 2010, future net revenues are calculated using prices that represent the average of the first day of the month price for the 12-month period prior to the end of the period.

Such prices are utilized except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts, including the effects of derivatives qualifying as cash flow hedges. On December 12, 2011, the Company monetized its entire hedge portfolio. Therefore, there was no impact of derivatives qualifying as cash flows hedges on the ceiling test as of December 31, 2011. As of December 31, 2010 and 2009, based on average prices for the prior 12-month period for natural gas and oil, cash flow hedges increased the full-cost ceiling by $52.3 million and $69.7 million, respectively, thereby reducing the ceiling test write-down by the same amount. Our natural gas and oil hedging activities are discussed in "Note E—Derivative Activities," of these consolidated financial statements.

Two primary factors impacting the ceiling test are reserve levels and natural gas and oil prices, and their associated impact on the present value of estimated future net revenues. Revisions to estimates of natural gas and oil reserves and/or an increase or decrease in prices can have a material impact on the present value of estimated future net revenues. Any excess of the net book value, less deferred income taxes, is generally written off as an expense. As a result of the Company's ceiling test as of December 31, 2011, 2010 and 2009, the Company recorded impairment expense of $196.4 million, $132.8 million and $188.2 million, respectively.

During December 2011, the Company agreed to sell a term overriding royalty interest, or volumetric production payment ("VPP"), in certain long-lived producing assets in the H/B layer in East Texas and received cash proceeds of $49.7 million. The VPP is for approximately 14.7 Bcf to be produced over the next ninety-five months which commenced in December 2011. The VPP was treated as a sale of oil and gas properties and no gain or loss was recognized on the sale in accordance with the SEC accounting guidance for companies accounting for their oil and gas properties under the full cost method. Our oil and natural gas properties presented on our balance sheets as of December 31, 2011, have been reduced accordingly.

PROPERTY AND EQUIPMENT: Property and equipment are capitalized and stated at cost, while maintenance and repairs are expensed currently. Depreciation and amortization of other property and equipment are provided when assets are placed in service using the straight-line method based on estimated useful lives ranging from three to twenty years. In 2009, we changed the estimated useful life of the pipeline assets from 10 to 20 years. Depreciation and amortization expense for property and equipment was $6.0 million, $5.1 million and $7.1 million for the years ending December 31, 2011, 2010 and 2009, respectively.

IMPAIRMENT OF LONG-LIVED ASSETS: Pipeline and gathering system assets and other long-lived assets used in operations are periodically assessed to determine if circumstances indicate that the carrying amount of an asset may not be recoverable. An impairment loss is recognized only if the carrying amount of a long-lived asset is not recoverable from its undiscounted cash flows. An impairment loss is the difference between the carrying amount and fair value of the asset. The Company had no such impairment losses for the years ended December 31, 2011, 2010 and 2009.

ASSETS HELD FOR SALE: Assets held for sale are carried on the balance sheet at their carrying value or fair value less cost to sell, whichever is less. Subsequent increases in fair value less cost to sell will be recognized as a gain, but not in excess of the cumulative loss previously recognized. As a result of determining fair value on the assets held for sale and changes in selling cost estimates, an impairment loss was recorded for the years ended December 31, 2011 and 2010 on the assets held for sale in the amount of $9.3 million and $10.9 million, respectively. As of December 31, 2011 and 2010, estimated selling costs on the remaining assets held for sale were estimated to be $0.1 million and $1.3 million, respectively.

DEBT ISSUE COSTS: The Company amortizes debt issue costs related to its 5.00% Convertible Senior Notes, 4.50% Convertible Senior Notes, 11.375% Senior Notes, and Senior Secured Notes as interest expense over the scheduled maturity period of the debt. Unamortized debt issue costs were approximately $10.1 million and $9.1 million as of December 31, 2011 and 2010, respectively.

REVENUE DISTRIBUTIONS PAYABLE: For certain oil and natural gas properties, the Company receives production proceeds from the purchaser and further distributes such amounts to other revenue and royalty owners. Production proceeds applicable to other revenue and royalty owners are reflected as revenue distributions payable in the accompanying balance sheets. We recognize revenue for only our net interest in oil and natural gas properties.

DEFERRED INCOME TAXES: Deferred income taxes are provided for significant carryforwards and temporary differences between the tax basis of an asset or liability and its reported amount in the financial statements that will result in taxable or deductible amounts in future years. Deferred income tax assets or liabilities are determined by applying the presently enacted tax rates and laws. The Company records a valuation allowance for the amount of net deferred tax assets when, in management's opinion, it is more likely than not that such assets will not be realized.

The Company recognizes the financial statement effects of tax positions when it is more likely than not, based on the technical merits, that the position will be sustained upon examination by a taxing authority. Recognized tax positions are initially and subsequently measured as the largest amount of tax benefit that is more likely than not of being realized upon ultimate settlement with a taxing authority. Liabilities for unrecognized tax benefits related to such tax positions are included in other long-term liabilities unless the tax position is expected to be settled within the upcoming year, in which case the liabilities are included in accrued expenses and other current liabilities. As of December 31, 2011 and 2010, the Company had no such liabilities.

REVENUE RECOGNITION: Natural gas and crude oil revenues are recognized when sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred, and if collectability of the revenue is probable. Delivery occurs and title is transferred when production has been delivered to a purchaser's pipeline or truck. As a result of the numerous requirements necessary to gather information from purchasers or various measurement locations, calculate volumes produced, perform field and wellhead allocations and distribute and disburse funds to various working interest partners and royalty owners, the collection of revenues from oil and gas production may take up to 60 days following the month of production. Therefore, the Company makes accruals for revenues and accounts receivable based on estimates of its share of production, particularly from properties that are operated by others. Since the settlement process may take 30 to 60 days following the month of actual production, the Company's financial results include estimates of production and revenues for the related time period. The Company records any differences, which are not expected to be significant, between the actual amounts ultimately received and the original estimates in the period they become finalized.

NATURAL GAS BALANCING: During the course of normal operations, the Company and other joint interest owners of natural gas reservoirs will take more or less than their respective ownership share of the natural gas volumes produced. These volumetric imbalances are monitored over the lives of the wells' production capability. If an imbalance exists at the time the wells' reserves are depleted, cash settlements are made among the joint interest owners under a variety of arrangements. The Company follows the sales method of accounting for gas imbalances. A liability is recorded when the Company's natural gas volumes exceed its estimated remaining recoverable reserves. No receivables are recorded for those wells where the Company has taken less than its ownership share of gas production. There are no significant imbalances as of December 31, 2011 and 2010.

PRODUCTION AND SEVERANCE TAXES: Production taxes are set by state and local governments and vary as to the tax rate and the value to which that rate is applied. In Texas, where substantially all of our production is derived, severance taxes are levied as a percent of revenue received. The rate in Texas is complicated by certain severance tax exemptions or rate deductions on high cost wells. Certain wells, including all of our H/B wells, qualify for full severance tax relief for a period of ten years or recovery of 50% of the cost of drilling and completions, whichever is less. As a result, refunds for severance tax paid to the State of Texas on wells that qualify for reimbursement are recognized as accounts receivable and offset severance tax expense for the amount refundable as of December 31, 2011 and 2010 (net of filing fees paid to a third party). Prior to 2010, credits were not recognized until approvals were received. Production and severance taxes for the years ended December 31, 2011, 2010 and 2009 reflect tax refunds received and accrued of $3.5 million, $3.1 million and $2.9 million, respectively.

DERIVATIVE INSTRUMENTS: The Company uses derivative financial instruments to manage its exposure to lower oil and natural gas prices. Derivative instruments are measured at fair value and recognized as assets or liabilities in the balance sheet. Upon entering into a derivative contract, the derivative may be designated as a cash flow hedge. The relationship between the derivative instrument designated as a hedge and the hedged items is documented, as well as our objective for risk management and strategy for use of the hedging instrument to manage the risk. Derivative instruments designated as cash flow hedges are linked to specific forecasted transactions. At inception, and on an ongoing basis, a derivative instrument used as a hedge is assessed as to whether it is highly effective in offsetting changes in the cash flows of the hedged item. A derivative that is not a highly effective hedge does not qualify for hedge accounting.

Changes in fair value of a qualifying cash flow hedge are recorded in accumulated other comprehensive income, until earnings are affected by the cash flows of the hedged item. When the cash flow of the hedged item is recognized in the statement of operations, the fair value of the associated cash flow hedge is reclassified from accumulated other comprehensive income into earnings as a component of oil and gas sales. Ineffective portions of a cash flow hedge are recognized currently in earnings as a component of oil and gas sales. The changes in fair value of derivative instruments not qualifying or not designated as hedges are reported currently in the consolidated statement of operations as gains (losses) on derivatives, a component of non-operating income (expense). For the year ended December 31, 2011, the changes in the fair value of the derivative instruments were realized upon the monetization of the Company's hedge portfolio in December 2011. For the years ended December 31, 2010 and 2009 the changes in the fair value of the derivative instruments were unrealized. If a derivative instrument no longer qualifies as a cash flow hedge, hedge accounting is discontinued and the gain or loss that was recorded in accumulated other comprehensive income is recognized over the period anticipated in the original hedge transaction.

FAIR VALUE. Fair value is defined as the price that would be received to sell an asset or price paid to transfer a liability in an orderly transaction between market participants at the measurement date. Inputs used in determining fair value are characterized according to a hierarchy that prioritizes those inputs based upon the degree to which they are observable. The three levels of the fair-value-measurement hierarchy are as follows:

Level 1—inputs represent quoted prices in active markets for identical assets or liabilities (for example, exchange-traded commodity derivatives).

Level 2—inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly (for example, quoted market prices for similar assets or liabilities in active markets or quoted market prices for identical assets or liabilities in markets not considered to be active, inputs other than quoted prices that are observable for the asset or liability, or market-corroborated inputs).

Level 3—inputs that are not observable from objective sources, such as the Company's internally developed assumptions used in pricing an asset or liability.

In determining fair value, the Company utilizes observable market data when available, or models that incorporate observable market data. In addition to market information, the Company incorporates transaction-specific details that, in management's judgment, market participants would take into account in measuring fair value. In arriving at fair-value estimates, the Company utilizes the most observable inputs available for the valuation technique employed. If a fair-value measurement reflects inputs at multiple levels within the hierarchy, the fair-value measurement is characterized based upon the lowest level of input that is significant to the fair-value measurement. Recurring fair-value measurements are performed for derivatives instruments. The carrying amount of cash and cash equivalents, accounts receivable and accounts payable reported on the balance sheet approximates fair value.

ASSET RETIREMENT OBLIGATIONS: The Company's asset retirement obligations relate to estimated future plugging and abandonment expenses on its oil and gas properties and related facilities disposal. These obligations to abandon and restore properties are based upon estimated future costs that may change based upon future inflation rates and changes in statutory remediation rules. The Company records the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of oil and gas properties.

ENVIRONMENTAL LIABILITIES: Environmental expenditures that relate to an existing condition caused by past operation and that do not contribute to current or future revenue generation are expensed. Liabilities are accrued when environmental assessments and/or clean-ups are probable, and the costs can be reasonably estimated. As of December 31, 2011 and 2010, the Company has not accrued for or been fined or cited for any environmental violations that would have a material adverse effect upon the financial position, operating results or the cash flows of the Company.

BASIC EARNINGS PER SHARE AND DILUTED EARNINGS PER SHARE: Basic net income per common share is computed by dividing the net income (loss) applicable to common stock by the weighted average number of shares of common stock outstanding during the period. Diluted net income per common share is calculated in the same manner, but also considers the impact to net income and common shares for the potential dilution from our convertible notes, outstanding stock options and non-vested restricted stock awards. The following table reconciles the weighted average shares outstanding used for these computations for the years ending December 31:

	2011	2010	2009
Weighted average shares outstanding—basic	53,071,200	28,206,506	20,210,400
Effective of dilutive securities:			
Stock options	—	—	—
Weighted average shares outstanding—diluted	53,071,200	28,206,506	20,210,400

Common shares outstanding loaned in connection with the 5.00% Convertible Senior Notes issued in February 2008 in the amount of 2,364,375, 2,640,000 and 3,140,000 shares were not included in the computation of earnings per common share for the years ending December 31, 2011, 2010 and 2009, respectively.

For purposes of calculating weighted average common shares—diluted, non-vested restricted stock and outstanding stock options would be included in the computation using the treasury stock method, with the proceeds equal to the amount of cash received from the employee upon exercise and the average unrecognized compensation during the period, adjusted for any estimated future tax consequences recognized directly in equity.

Due to our net loss from operations for the years ended December 31, 2011, 2010 and 2009, we excluded the effects of the convertible notes, stock options and shares of non-vested restricted stock as they would have been antidilutive. Dilutive shares are calculated under the accounting guidance of FASB ASC 260-10, "Earnings Per Share." Under this accounting guidance, assuming the Company had net income for the year ended December 31, 2011, there would be no dilutive shares as of December 31, 2011. The amount of shares excluded from diluted weighted average shares outstanding for 2010 and 2009 was 66,061 and 794,000, respectively.

STOCK BASED COMPENSATION: The Company recognizes compensation expense for all stock-based payment awards made to employees, contractors and non-employee directors. Stock-based compensation expense is measured at the grant date based on the fair value of the award and is recognized as expense over the requisite service period, which is generally the vesting period. For stock options, the Company uses the Black-Scholes option-pricing model to determine the option fair value, which requires the input of highly subjective assumptions, including the expected volatility of the underlying stock, the expected term of the award, the risk-free interest rate and expected future divided payments. Expected volatilities are based on our historical volatility. The expected life of an award is estimated using historical exercise behavior data and estimated future behavior. The risk-free interest rate is based on the U.S. Treasury yields in effect at the time of grant and extrapolated to approximate the expected life of the award. The Company does not expect to declare or pay dividends in the foreseeable future.

COMMITMENTS AND CONTINGENCIES: Liabilities for loss contingencies arising from claims, assessments, litigation, or other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated.

SUPPLEMENTAL DISCLOSURE OF NON-CASH INVESTING AND FINANCING ACTIVITIES: During the years ended December 31, 2011, 2010 and 2009, the Company recorded non-cash additions to oil and gas properties of \$0.6 million, \$1.0 million and \$1.2 million, respectively related to the depreciation of its Company-owned rigs and the capitalization of non-cash stock compensation expense related to employees directly involved in exploration and development activities.

Capital additions due to increase/(decreases) in accounts payable was ($20.9) million, $14.6 million and $25.6 million for the years ended December 31, 2011, 2010 and 2009, respectively.

During the years ended December 31, 2011, 2010 and 2009, the Company recorded a net non-cash asset and a related liability of $0.4 million, $0.7 million and $0.6 million, respectively, associated with the asset retirement obligation on the acquisition and/or development of oil and gas properties.

During the year ended December 31, 2011 the Company recorded additions to oil and natural gas properties in exchange for common stock of $31.6 million related to the acreage acquisitions in the Bakken/Three Forks and Niobrara.

Cash paid for interest, net of amounts capitalized, was $22.5 million, $12.0 million and $15.6 million for the years ended December 31, 2011, 2010 and 2009, respectively. Interest of $7.8 million, $2.6 million and $1.8 million, was capitalized during the years ended December 31, 2011, 2010 and 2009, respectively, related to the unproved properties that were not being currently depreciated, depleted or amortized and on which exploration or development activities were in progress.

Cash paid/(received) for income taxes was $1,000, ($30,000) and ($33,000) for the years ended December 31, 2011, 2010 and 2009, respectively.

RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS:

In June 2011, the FASB issued ASU No. 2011-05, Presentation of Comprehensive Income. The issuance of ASU 2011-5 is intended to improve the comparability, consistency and transparency of financial reporting and to increase the prominence of items reported in other comprehensive income. The guidance in ASU 2011-5 supersedes the presentation options in ASC Topic 220 and facilitates convergence of U.S. generally accepted accounting principles and International Financial Reporting Standards by eliminating the option to present components of other comprehensive income as part of the statement of changes in shareholders' equity and requiring that all non-owner changes in shareholders' equity be presented either in a single continuous statement of comprehensive income or in two separate but consecutive statements. This guidance will be applied retrospectively and early adoption is permitted. This guidance is effective for fiscal years and interim periods within those years, beginning after December 15, 2011. The adoption of this guidance is not expected to have a material impact on the Company's consolidated financial statements.

In May 2011, the FASB issued ASU 2011-04, Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S GAAP and IFRSs. This amendment of the FASB Accounting Standards Codification is to ensure that fair value has the same meaning in U.S. GAAP and IFRS and that their respective fair value measurement and disclosure requirements are the same. This guidance is effective during the interim and annual periods beginning after December 15, 2011. The Company does not expect that this authoritative guidance will have any material effect on the Company's financial statements.

In December 2009, the Company adopted revised oil and gas reserve estimation and disclosure requirements. The primary impact of the new disclosures for the Company was to align the definition of proved reserves with the Securities and Exchange Commission (SEC) Modernization of Oil and Gas Reporting rules, which were issued by the SEC at the end of 2008 and effective for fiscal periods ending on or after December 31, 2009. The accounting standards revised the definition of proved oil and gas reserves to require that the average, first-day-of-the-month price during the 12-month period preceding the end of the year rather than the year-end price, must be used when estimating whether reserve quantities are economical to produce. This same 12-month average price is also used in calculating the aggregate amount of (and changes in) future cash inflows related to the standardized measure of discounted future net cash flows. The rules also allow for the use of reliable technology to estimate proved oil and gas reserves, if those technologies have been demonstrated to result in reliable conclusions about reserve volumes. The unaudited supplemental information on oil and gas exploration and production activities for 2011, 2010 and 2009 has been presented following these new reserve estimation and disclosure rules.

NOTE B—SHARE LENDING ARRANGEMENTS AND ADOPTION OF ASU 2009-15

In February 2008, in connection with the offer and sale of the 5.00% convertible notes, we entered into a share lending agreement (the "Share Lending Agreement") with an affiliate of Jefferies & Company, Inc. (the "Share Borrower") and Jefferies & Company, Inc., as collateral agent for GMX. Under this agreement, we may loan to the Share Borrower up to the maximum number of shares of our common stock underlying the 5.00% convertible notes during a specified loan availability period. This maximum number of shares was initially 3,846,150 shares. We will receive a loan fee of $0.001 per share for each share of our common stock that we loan to the Share Borrower, payable at the time such shares are borrowed. The Share Borrower may borrow and re-borrow up to the maximum number of shares of our common stock during the loan availability period.

The Share Borrower's obligations under the Share Lending Agreement are unconditionally guaranteed by Jefferies Group, Inc., the ultimate parent company of the Share Borrower and Jefferies & Company, Inc. (the "guarantor"). If the guarantor receives a rating downgrade for its long term unsecured and unsubordinated debt below a specified level by both Standard & Poor's Ratings Services and Moody's Investors Service, Inc. (or any substitute rating agency mutually agreed upon by the Company and the Share Borrower), or by either of such rating agencies in certain circumstances, the Share Borrower has agreed to post and maintain with Jefferies & Company, Inc., acting as collateral agent for the Company, collateral in the form of cash, government securities, certificates of deposit, high-grade commercial paper of U.S. issuers, letters of credit or money market shares with a market value at least equal to 100% of the market value of the shares of our common stock borrowed by the Share Borrower as security for the Share Borrower's obligation to return the borrowed shares to the Company pursuant to the Share Lending Agreement.

The loan availability period under the Share Lending Agreement commenced on the date of the Share Lending Agreement and will continue until the date that any of the following occurs:

- the Company notifies the Share Borrower in writing of our intention to terminate the Share Lending Agreement at any time after the entire principal amount of the 5.00% convertible notes ceases to be outstanding as a result of conversion, repurchase, at maturity or otherwise;
- the Company and the Share Borrower agree to terminate the Share Lending Agreement;
- the Company elects to terminate all of the outstanding loans upon a default by the Share Borrower under the Share Lending Agreement or by the guarantor under its guarantee, including a breach by the Share Borrower of any of its obligations or a breach in any material respect of any of the representations or covenants under the Share Lending Agreement or a breach by the guarantor of the guarantee, or the bankruptcy of the Share Borrower or the guarantor; or
- the Share Borrower elects to terminate all outstanding loans upon the bankruptcy of the Company.

Any shares the Company loans to the Share Borrower will be issued and outstanding for corporate law purposes, however, the borrowed shares will not be considered outstanding for the purpose of computing and reporting earnings per share. The holders of the borrowed shares will have all of the rights of a holder of a share of our outstanding common stock, including the right to vote the shares on all matters submitted to a vote of the Company's shareholders and the right to receive any dividends or other distributions that we may pay or make on our outstanding shares of common stock. However, under the Share Lending Agreement, the Share Borrower has agreed:

- not to vote any shares of the Company's common stock it has borrowed to the extent it owns such borrowed shares; and
- to pay to the Company an amount equal to any cash dividends that are paid on the borrowed shares.

On January 1, 2010, the Company adopted, retrospectively, ASU 2009-15, Accounting for Own-Share Lending Arrangements in Contemplation of Convertible Debt Issuance or Other Financing, which changed the accounting treatment of the Company's share lending arrangements. Under ASU 2009-15, the Company must recognize the value of share lending arrangements as issuance cost at inception.

As of December 31, 2011 and 2010, respectively, 2,364,375 and 2,640,000, shares of our common stock were subject to outstanding loans to the Share Borrower with a fair value of $3.0 million and $14.6 million. As of December 31, 2011 and 2010, respectively, the unamortized amount of issuance costs associated with the share lending agreement was $1.0 million and $1.7 million. The Company recognized $0.8 million, $0.7 million and $0.6 million in interest expense relating to the amortization of the Share Lending Agreement for the years ended December 31, 2011, 2010 and 2009, respectively.

NOTE C—NONCONTROLLING INTEREST

On November 1, 2009, GMX and its wholly owned subsidiary, Endeavor Pipeline, transferred mid-stream gas gathering, compression and related equipment to a newly formed Endeavor Gathering and sold a 40% membership interest in Endeavor Gathering to KME for $36.0 million. Endeavor Gathering provides firm capacity gathering services to the Company in our Cotton Valley Sands and Haynesville/Bossier Shale horizontal developments in East Texas, and will also provide funding of future gathering infrastructure needs to support the Company's production growth. The results of operations and financial position of Endeavor Gathering are included in the consolidated financial statements of GMX. The portion of Endeavor Gathering's results of operations not attributable to GMX are recorded as noncontrolling interests.

Distributions to the members will be made on a monthly basis to the members and allocated 80% and 20% to the noncontrolling interest and to GMX, respectively until the noncontrolling interest member has received $36.0 million. Subsequently, distributions will be allocated 40% and 60% to the noncontrolling interest member and GMX, respectively.

The following table sets forth the effects of changes in GMX's ownership interest in Endeavor Gathering on GMX's equity for the years ended December 31:

	2011	2010	2009
		(in thousands)	
Net loss applicable to GMX	$ (211,837)	$ (141,406)	$ (181,260)
Transfers from the noncontrolling interest:			
Increase in GMX paid-in capital for sale of 40% membership interest in Endeavor Gathering	$ —	$ —	13,984
Change from net loss applicable to GMX and transfers from noncontrolling interest	$ (211,837)	$ (141,406)	$ (167,276)

NOTE D—PROPERTY AND EQUIPMENT AND ASSETS HELD FOR SALE

Major classes of property and equipment included the following at December 31:

	December 31,	
	2011	2010
	(in thousands)	
Pipeline and related facilities	$ 58,189	$ 57,798
Machinery and equipment	5,622	5,576
Buildings and leasehold improvement	8,838	8,418
Office equipment	5,790	4,619
	78,439	76,411
Less accumulated depreciation and amortization	(14,847)	(9,455)
	63,592	66,956
Land	2,266	2,081
	$ 65,858	$ 69,037

In December 2010, the Company finalized a plan to dispose of three drilling rigs, four compressors, pipe and valves by sale. The majority of these assets were disposed of throughout 2011 and the remaining assets held for sale as of December 31, 2011 consists of one compressor and valves. These assets will either be disposed of individually or as part of a disposal group, depending on the purchaser's interest. The accounting for these assets at the plan date was in accordance with ASC 360-10, Property, Plant and Equipment. Under this guidance, the assets are carried on the balance sheet at their carrying value or fair value less cost to sell, whichever is less. Subsequent increases in fair value less cost to sell will be recognized as a gain, but not in excess of the cumulative loss previously recognized. In determining fair value for the drilling rigs, management used third party appraisals. For all other assets, management performed internal estimates of the value of the assets based on verbal bids gathered through their marketing efforts and other marketing information. Management also performed internal estimates on the cost to sell the assets, which primarily consisted of commissions to sell the assets, and were estimated based on past experience selling similar assets and verbal bids. As a result of determining fair value on the assets held for sale and changes in selling cost estimates, an impairment loss was recorded for the year ended December 31, 2011 and 2010 on the assets held for sale in the amount of $9.3 million and $10.9 million, respectively, which was included in the Impairment of Oil and Natural Gas Properties and Assets Held for Sale in the Statements of Operations. As of December 31, 2011 and 2010, selling costs on the remaining assets held for sale were estimated to be $0.1 million and $1.3 million, respectively.

NOTE E—DERIVATIVE ACTIVITIES

The Company is subject to price fluctuations for natural gas and crude oil. Prices received for natural gas and crude oil sold on the spot market are volatile due to factors beyond the Company's control. Reductions in crude oil and natural gas prices could have a material adverse effect on the Company's financial position, results of operations, capital expenditures and quantities of reserves recoverable on an economic basis. Any reduction in reserves, including reductions due to lower prices can adversely affect the Company's liquidity and ability to obtain capital for acquisition and development activities.

To mitigate a portion of its exposure to fluctuations in commodity prices, the Company enters into financial price risk management activities with respect to a portion of projected crude oil and natural gas production through financial price swaps, collars, and put spreads (collectively "derivatives"). Additionally, the Company uses basis protection swaps to reduce basis risk. Basis is the difference between the physical commodity being hedged and the price of the futures contract used for hedging. Basis risk is the risk that an adverse change in the futures market will not be completely offset by an equal and opposite change in the cash price of the commodity being hedged. Basis risk exists in natural gas due to the geographic price differentials between a given cash market location and the futures contract delivery locations. Settlement or expiration of the hedges is designed to coincide as closely as possible with the physical sale of the commodity being hedged—daily for oil and monthly for natural gas—to obtain reasonable assurance that a gain in the cash sale will offset the loss on the hedge and vice versa.

The Company's derivative financial instruments potentially consist of price swaps, collars, put spreads and basis swaps. A description of these types of instruments is provided below:

Fixed price swaps	The Company receives a fixed price and pays a variable price to the contract counterparty. The fixed-price payment and the floating price payment are netted, resulting in a net amount due to or from the counterparty.
Costless collars	The instrument contains a fixed floor price (long put option) and ceiling price (short call option), where the purchase price of the put option equals the sales price of the call option. At settlement, if the market price exceeds the ceiling price, the Company pays the difference between the market price and the ceiling price. If the market price is less than the fixed floor price, the Company receives the difference between the fixed floor price and the market price. If the market price is between the ceiling and the fixed floor price, no payments are due from either party.
Three-way collars	A three-way collar contract consists of a standard collar contract plus a put sold by the Company with a price below the floor price of the collar. This additional put requires us to make a payment to the counterparty if the settlement price for any settlement period is below the put price. Combining the collar contract with the additional put results in the Company being entitled to a net payment equal to the difference between the floor price of the standard collar and the additional put price if the settlement price is equal to or less than the additional put price. If the settlement price is greater than the additional put price, the result is the same as it would have been with a standard collar contract only. Therefore, if market prices are below the additional put option, the Company would be entitled to receive the market price plus the difference between the additional put option and the floor. This strategy enables the Company to increase the floor and the ceiling price of the collar beyond the range of a traditional costless collar while defraying the associated cost with the sale of the additional put.
Put spreads	A put spread is the same as a three-way collar without the ceiling price (short call option). Therefore, if market prices are below the additional put option, the Company would be entitled to receive the market price plus the difference between the additional put option and the floor.
Basis swaps	Natural gas basis protection swaps are arrangements that guarantee a price differential between NYMEX natural gas futures and Houston Ship Channel or Mainline (Columbia Gulf), which is a close proximity for the Company's primary market hubs. The Company receives a payment from the counterparty if the price differential is less than the stated terms of the contract and pays the counterparty if the price differential is greater than the stated terms of the contract.

The Company utilizes counterparties that the Company believes are credit-worthy entities at the time the transactions are entered into. The Company closely monitors the credit ratings of these counterparties. Additionally, the Company performs both quantitative and qualitative assessments of these counterparties based on their credit ratings and credit default swap rates where applicable. However, the recent events in the financial markets demonstrate there can be no assurance that a counterparty financial institution will be able to meet its obligations to the Company.

None of the Company's derivative instruments contain credit-risk-related contingent features. Additionally, the Company has not incurred any credit-related losses associated with derivative activities and believes that its counterparties will continue to be able to meet their obligations under these transactions.

ASC 815, Derivatives and Hedging requires all derivative instruments to be recognized at fair value in the balance sheet. Fair value is generally determined based on the difference between the fixed contract price and the underlying estimated market price at the determination date. Derivative instruments with the same counterparty are presented on a net basis where the legal right of offset exists.

In December 2011, the Company settled its entire hedge portfolio and received $18.5 million, net of the $0.2 million paid to settle the oil hedges and $8.5 million paid on the deferred hedge premiums. In addition, $0.2 million in deferred costs related to unamortized accretion were recorded to expense. Under ASC 815-30-40, the Company is required to recognize the balance of the cumulative gain, recorded in accumulated other comprehensive income in the previous periods, over the life of the remaining contractual life of the original hedged transaction. As of December 31, 2011, the balance of the Company's cumulative gain, net of taxes, recorded in accumulated other comprehensive income in previous periods was $14.0 million, of which $7.4 million will be recognized into earnings through December 31, 2012, with the remainder recognized in 2013.

The following is a summary of the asset and liability fair values of the Company's derivative contracts:

	Balance Sheet Location	Asset Fair Value December 31, 2011	Asset Fair Value December 31, 2010	Liability Fair Value December 31, 2011	Liability Fair Value December 31, 2010	Net Derivative Fair Value December 31, 2011	Net Derivative Fair Value December 31, 2010
		(in thousands)		(in thousands)		(in thousands)	
Derivatives designated as Hedging Instruments under ASC 815							
Natural gas....	Current derivative asset	$ —	$ 23,187	$ —	$ 2,963	$ —	$ 20,224
Natural gas basis.............	Current derivative asset	—	—	—	566	—	(566)
Natural gas....	Derivative instruments – non-current asset	—	20,503	—	2,897	—	17,606
Natural gas basis.............	Derivative instruments – non-current asset	—	—	—	122	—	(122)
		$ —	$ 43,690	$ —	$ 6,548	$ —	$ 37,142
Derivatives not designated as Hedging Instruments under ASC 815							
Natural gas....	Current derivative asset	$ —	$ —	$ —	$ —	$ —	$ —
Crude oil.......	Current derivative asset	—	—	—	172	—	(172)
Natural gas....	Derivative instruments – non-current asset	—	—	—	—	—	—
Crude oil.......	Derivative instruments – non-current asset	—	—	—	—	—	—
		$ —	$ —	$ —	$ 172	$ —	$ (172)
Net derivative fair value.......						$ —	$ 36,970

All of the above natural gas contracts are settled against NYMEX and all oil contracts are settled against NYMEX Light Sweet Crude. The NYMEX and NYMEX Light Sweet Crude have historically had a high degree of correlation with the actual prices received by the Company.

Effects of derivative instruments on the Consolidated Statement of Operations

For derivative instruments that are designated and qualify as a cash flow hedge, the effective portion of the gain or loss on the derivative is reported as a component of other comprehensive income ("OCI") and reclassified into earnings in the same period or periods during which the hedged transaction affects earnings. Gains and losses on the derivative representing either hedge ineffectiveness or hedge components excluded from the assessment of effectiveness are recognized in current earnings.

The following is a summary of the results of the derivative contacts on other comprehensive income and the consolidated statements of operations.

Description	Location of Amounts	Natural Gas Derivatives Qualifying as Hedges — For the Year Ended December 31, 2011	2010	2009
			(in thousands)	
Amount of Gain (Loss) Recognized in OCI on Derivative (Effective Portion)	OCI	16,924	33,858	20,911
Amount of Gain Reclassified from Accumulated OCI into Income (Effective Portion)	Oil and Gas Sales	18,740	23,585	28,546
Amount of Gain (Loss) Recognized in Income on Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing)	Oil and Gas Sales	114	(1,280)	1,018

Description	Location of Amounts	Crude Oil Derivatives Qualifying as Hedges — For the Year Ended December 31, 2011	2010	2009
			(in thousands)	
Amount of Gain (Loss) Recognized in OCI on Derivative (Effective Portion)	OCI	—	—	(437)
Amount of Gain Reclassified from Accumulated OCI into Income (Effective Portion)	Oil and Gas Sales	—	—	2,305
Amount of Gain (Loss) Recognized in Income on Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing)	Oil and Gas Sales	—	—	—

For derivative instruments that do not qualify as hedges pursuant to ASC 815, changes in the fair value of these derivatives that occur prior to their maturity (i.e., temporary fluctuations in value) are recognized in current earnings. A summary of the effect of the derivatives not qualifying for hedges is as follows:

	Location of Gain (Loss) Recognized in Income on Derivative	Amount of Gain (Loss) Recognized in Income on Derivative — For the Year Ended December 31, 2011	2010	2009
Realized				
Natural gas	Oil and Gas Sales	$ —	$ (23)	$ 5,920
Crude Oil	Oil and Gas Sales	(44)	—	—
Natural gas	Gain (loss) on derivatives	3,599	—	—
Crude Oil	Gain (loss) on derivatives	13	—	—
Unrealized				
Natural gas	Gain (loss) on derivatives	—	(221)	(2,100)
Natural gas basis	Gain (loss) on derivatives	—	—	(270)
Crude Oil	Gain (loss) on derivatives	—	99	—
		$ 3,568	$ (145)	$ 3,550

The valuation of our derivative instruments are based on industry standard models that primarily rely on market observable inputs. Substantially all of the assumptions for industry standard models are observable in active markets throughout the full term of the instrument. The Company categorizes these measurements as Level 2. The following table sets forth by level within the fair value hierarchy our derivative instruments, which are our only financial assets and liabilities that were accounted for at fair value on a recurring basis, as of December 31, 2011 and 2010:

	As of December 31, 2011:			As of December 31, 2010:		
	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	(in thousands)					
Financial assets:						
Natural gas derivative instruments	$ —	$ —	$ —	$ —	$ 37,142	$ —
Crude oil derivative instruments	$ —	$ —	$ —	$ —	$ (172)	$ —

NOTE F—LONG-TERM DEBT

The table below presents the carrying amounts and approximate fair values of our debt obligations. The carrying amounts of our revolving bank credit facility borrowings approximate their fair values due to the short-term nature and frequent repricing of these obligations. The approximate fair values of our convertible debt securities are determined based on market quotes from independent third party brokers as they are actively traded in an established market.

	December 31,			
	2011		2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in thousands)			
Revolving bank credit facility	$ —	$ —	$ 92,000	$ 92,000
5.00% Senior Convertible Notes due February 2013	70,757	46,560	116,365	105,258
4.50% Senior Convertible Notes due May 2015	77,457	41,400	75,238	63,825
11.375% Senior Notes due February 2019	1,912	1,300	—	—
Senior Secured Notes due December 2017	275,411	283,475	—	—
Joint venture financing[1]	1,294	1,294	1,366	1,366
Total	$ 426,831	$ 374,029	$ 284,969	$ 262,449

(1) Non-recourse, no interest rate

Maturities of Long-Term Debt

Maturities of long-term debt as of December 31, 2011 are as follows:

Year	Amount (in thousands)
2012	$ 26
2013	72,801
2014	44
2015	86,287
2016	33
Thereafter	286,548
	$ 445,739

Revolving Bank Credit Facility

On December 12, 2011, the Company fully repaid the outstanding balance on our secured revolving bank credit facility of $39.1 million and terminated the bank credit facility in connection with the closing of the VPP transaction. There were no amounts outstanding under any revolving credit facilities as of December 31, 2011. On the date of termination, the Company had $1.6 million in unamortized debt issue costs, which was expensed and included in gain (loss) on extinguishment of debt.

5.00% Convertible Senior Notes

In February 2008, the Company completed a $125 million private placement of 5.00% convertible senior notes due 2013 ("5.00% Convertible Notes"). In connection with such offering, we agreed to loan up to 3,846,150 shares of our common stock to an affiliate of Jefferies & Company, Inc. to facilitate hedging transactions by purchasers of the notes.

As of December 31, 2011 and 2010, unamortized debt issue costs were approximately $0.6 million and $1.9 million, respectively.

On December 21 and December 22, 2010, the Company entered into two separate agreements with a third party to retire $2.25 million of the 5.00% Convertible Notes for a combined total of 380,250 shares of the Company's common stock and $45,660 in cash. The cash consideration satisfied unpaid and accrued interest on the 5.00% Convertible Notes.

On January 28, 2011, the Company announced the commencement of a tender offer for up to $50 million aggregate principal amount of the outstanding 5.00% convertible notes. The tender offer expired March 11, 2011 and the Company retired $50 million aggregate principal amount of the 5.00% convertible notes. This transaction was accounted for under ASC 470-20-40. Under this guidance, the consideration transferred was allocated to the extinguishment of the liability and reacquisition of the original equity component resulting in a gain on extinguishment of debt of $2.1 million and a charge to additional-paid-in-capital of $5.2 million.

As a result of the adoption of the new authoritative accounting guidance under ASC 470-20 as of January 1, 2009 and its retrospective application, the Company recorded a debt discount of $14.3 million, which represented the fair value of the equity conversion feature, and recorded a corresponding increase in additional paid-in capital ("APIC"), net of deferred taxes. In addition, the transaction costs incurred directly related to the issuance of the 5.00% Convertible Notes were allocated proportionately to the equity conversion feature and recorded as APIC. The equity component is not subsequently re-valued as long as it continues to qualify for equity treatment.

The debt discount is amortized as additional non-cash interest expense over the expected term of the 5.00% Convertible Notes through February 2013. As of December 31, the net carrying amount was as follows (amounts in the thousands):

	2011	2010
Principal amount	$ 72,750	$ 122,750
Unamortized debt discount	(1,993)	(6,385)
Carrying amount	$ 70,757	$ 116,365

The 5.00% Convertible Notes bear interest at a rate of 5.00% per year, payable semiannually in arrears on February 1 and August 1 of each year, which began August 1, 2008. As a result of the amortization of the debt discount through non-cash interest expense, the effective interest rate on the 5.00% Convertible Notes is 6.57% per annum. The amount of the cash interest expense recognized with respect to the 5.00% contractual interest coupon for the years ended December 31, 2011 and 2010 was $4.2 million and $6.2 million, respectively. The amount of non-cash interest expense for the years ended December 31, 2011 and 2010 related to the amortization of the debt discount and amortization of the transaction costs was $2.6 million and $3.7 million, respectively. As of December 31, 2011, the unamortized discount is expected to be amortized into earnings over 1.1 years. The carrying value of the equity component of the 5.00% Convertible Notes was $9.2 million as of December 31, 2011.

Holders may convert their 5.00% Convertible Notes at their option prior to the close of business on the business day immediately preceding November 1, 2012 only under the following circumstances:

- during any fiscal quarter commencing after March 31, 2008 if the last reported sale price of the common stock for at least 20 trading days during a period of 30 consecutive trading days ending on the last trading day of the preceding fiscal quarter is greater than or equal to 130% of the applicable conversion price on each such trading day;
- during the five business-day period after any five consecutive trading-day period in which the trading price for each day of that measurement period was less than 98% of the last reported sale price of our common stock and the applicable conversion rate on each such day; or
- the occurrence of certain sales of assets, distributions or changes to distribution rights to common stockholders, mergers and consolidations, changes in management, or our common stock ceases to be listed on a United States national or regional securities exchange, among other things.

On and after November 1, 2012 until the close of business on the business day immediately preceding the maturity date, holders may convert their 5.00% Convertible Notes at any time, regardless of the foregoing circumstances.

Upon conversion, the Company will satisfy its conversion obligation by paying and delivering cash for the lesser of the principal amount or the conversion value, and, if the conversion value is in excess of the principal amount, by paying or delivering, at its option, cash and/or shares of its common stock for such excess. The conversion value is a daily value calculated on a proportionate basis for each day of a 60 trading-day observation period. The conversion rate is initially 30.7692 shares of the Company's common stock per $1,000 principal amount of notes (equivalent to a conversion price of approximately $32.50 per share of common stock). The conversion rate is subject to adjustment in some events but will not be adjusted for accrued interest. In addition, following any fundamental change that occurs prior to the maturity date, we will increase the conversion rate for a holder who elects to convert its 5.00% Convertible Notes in connection with such a fundamental change in certain circumstances. The increase in the conversion rate is determined based on a formula that takes into consideration our stock price at the time of the fundamental change (ranging from $25.00 to $150.00 per share) and the remaining time to maturity of the notes. The increase in the conversion rate ranges from 0% to 30% increasing as the stock price at the time of the fundamental change increases from $25.00 and declines as the remaining time to maturity of the notes decreases.

We may not redeem the 5.00% Convertible Notes prior to maturity. However, if we undergo a fundamental change, holders may require us to repurchase the 5.00% Convertible Notes in whole or in part for cash at a price equal to 100% of the principal amount of the 5.00% Convertible Notes to be repurchased plus any accrued and unpaid interest (including additional interest, if any) to, but excluding, the fundamental change repurchase date.

The 5.00% Convertible Notes are senior, unsecured obligations of the Company and rank equally in right of payment to all of our senior unsecured debt and our existing 4.50% Convertible Notes, and are senior in right of payment to our debt that is expressly subordinated to the 5.00% Convertible Notes, if any. The 5.00% Convertible Notes are structurally subordinated to all debt and other liabilities and commitments of our subsidiaries, including our subsidiaries' guarantees of our indebtedness under our Senior Secured Notes, and are effectively junior to our secured debt to the extent of the assets securing such debt.

4.50% Convertible Senior Notes

In October 2009, the Company completed a $86.3 million private placement of 4.50% convertible senior notes due 2015 ("4.50% Convertible Notes"). The proceeds of the offering were used to repay the Senior Subordinated Secured Notes due 2012 and a portion of the outstanding indebtedness under the revolving bank credit facility. The Company recorded a debt discount of $13.4 million, which represented the fair value of the equity conversion feature, and recorded a corresponding increase in APIC, net of deferred taxes. In addition, the transaction costs incurred directly related to the issuance of the 4.50% Convertible Notes were allocated proportionately to the equity conversion feature and recorded as APIC. The equity component is not subsequently re-valued as long as it continues to qualify for equity treatment. As of December 31, 2011, the net carrying amount was as follows (amounts in thousands):

	2011	2010
Principal amount	$ 86,250	$ 86,250
Unamortized debt discount	(8,793)	(11,012)
Carrying amount	$ 77,457	$ 75,238

As of December 31, 2011 and 2010, unamortized debt issue costs were approximately $2.4 million and $2.9 million, respectively.

The 4.50% Convertible Notes bear interest at a rate of 4.50% per year, payable semiannually in arrears on November 1 and May 1 of each year, beginning May 1, 2010. As a result of the amortization of the debt discount through non-cash interest expense, the effective interest rate on the 4.50% Convertible Notes is 9.09% per annum. The amount of the cash interest expense recognized with respect to the 4.50% contractual interest coupon for the year ended December 31, 2011 was $3.9 million. The amount of non-cash interest expense for the year ended December 31, 2011 related to the amortization of the debt discount and amortization of the transaction costs was $2.8 million. As of December 31, 2011, the unamortized discount is expected to be amortized into earnings over 3.3 years. The carrying value of the equity component of the 4.50% Convertible Notes was $8.4 million as of December 31, 2011.

The 4.50% Convertible Notes mature on May 1, 2015, unless earlier converted or repurchased by us. Holders may convert their notes prior to the close of business on the business day immediately preceding February 1, 2015, only under the following circumstances:

- during any fiscal quarter commencing after January 1, 2010, if the last reported sale price of our common stock for at least 20 trading days during a period of 30 consecutive trading days ending on the last trading day of the preceding fiscal quarter is greater than or equal to 130% of the applicable conversion price on each such trading day;

- during the five business-day period after any five consecutive trading-day period in which the trading price per $1,000 principal amount of 4.50% Convertible Notes for each day of such five consecutive trading-day period was less than 98% of the product of the last reported sale price of our common stock and the applicable conversion rate on each such day;
- upon the occurrence of a corporate event pursuant to which: (1) we issue rights to all or substantially all of the holders of our common stock entitling them to purchase, for a period of not more than 60 calendar days after the announcement date of such issuance to subscribe for or purchase, shares of our common stock at a price per share less than the average of the last reported sale prices of our common stock for the 10 consecutive trading day period ending on the trading day immediately preceding the date of announcement of such issuance; (2) we distribute to all or substantially all of the holders of our common stock our assets, debt securities or rights to purchase our securities, if the distribution has a per share value in excess of 10% of the last reported sale price for our common stock on the trading day immediately preceding the date of announcement of such distribution; or (3) we are a party to a consolidation, merger, binding share exchange, or transfer or lease of all or substantially all of our assets, pursuant to which our common stock would be converted into cash, securities or other assets;
- if: (1) a "person" or "group" within the meaning of Section 13(d) of the Exchange Act acquires more than 50% of our outstanding voting stock, (2) we consummate a recapitalization, reclassification or change of our common stock as a result of which our common stock would be converted into or exchanged for stock, other securities, other property or assets, less than 90% of which received by our common shareholders consists of publicly traded securities, (3) we consummate a share exchange, consolidation or merger pursuant to which our common stock will be converted into cash, securities or other property, (4) we consummate any sale, lease or other transfer in one transaction or a series of transactions of all or substantially all of our and our subsidiaries' consolidated assets to any person other than one of our subsidiaries, (5) continuing directors cease to constitute at least a majority of our board of directors, (6) our shareholders approve any plan or proposal for our liquidation or dissolution, or (7) our common stock ceases to be listed on any of The New York Stock Exchange, The NASDAQ Global Select Market or The NASDAQ Global Market; or
- if we call the 4.50% Convertible Notes for redemption, at any time prior to the close of business on the business day prior to the redemption date (any of the events described in the fourth and fifth bullets above, a "make-whole fundamental change").

On and after February 1, 2015 until the close of business on the business day immediately preceding the maturity date, holders may convert their 4.50% Convertible Notes, in multiples of $1,000 principal amount, at the option of the holder regardless of the foregoing circumstances.

Upon conversion, we will satisfy our conversion obligation by paying or delivering cash, shares of our common stock or a combination of cash and shares of our common stock, at our election. The conversion rate is initially 53.3333 shares of our common stock per $1,000 principal amount of 4.50% Convertible Notes (equivalent to a conversion price of approximately $18.75 per share of our common stock). The conversion rate is subject to adjustment in some events but will not be adjusted for accrued and unpaid interest. In addition, following any make-whole fundamental change that occurs prior to the maturity date, we will increase the conversion rate for a holder who elects to convert its 4.50% Convertible Notes in connection with such a make-whole fundamental change in certain circumstances. The increase in the conversion rate is determined based on a formula that takes into consideration our stock price at the time of the make-whole fundamental change (ranging from $15.00 to $100.00 per share) and the remaining time to maturity of the 4.50% Convertible Notes. The increase in the conversion rate declines from a high of 25.0% to 0.0% as the stock price at the time of the make-whole fundamental change increases from $15.00 and the remaining time to maturity of the 4.50% Convertible Notes decreases.

On or after November 1, 2012, and prior to the maturity date, we may redeem for cash all, but not less than all, of the 4.50% Convertible Notes if the last reported sales price of our common stock equals or exceeds 130% of the conversion price then in effect for 20 or more trading days in a period of 30 consecutive trading days ending on the trading day immediately prior to the date of the redemption notice. The redemption price will equal 100% of the principal amount of the 4.50% Convertible Notes to be redeemed, plus any accrued and unpaid interest, including any additional interest, to, but excluding, the redemption date. To the extent a holder converts its 4.50% Convertible Notes in connection with our redemption notice, we will increase the conversion rate as described in the preceding paragraph.

The 4.50% Convertible Notes are senior, unsecured obligations of the Company and rank equally in right of payment with our senior unsecured debt and our existing 5.00% Convertible Notes, and are senior in right of payment to our debt that is expressly subordinated to the 4.50% Convertible Notes, if any. The 4.50% Convertible Notes are structurally subordinated to all debt and other liabilities and commitments of our subsidiaries, including our subsidiaries' guarantees of our indebtedness under our Senior Secured Notes, and are effectively junior to our secured debt to the extent of the assets securing such debt.

11.375% Senior Notes

On February 9, 2011, the Company successfully completed the issuance and sale of $200 million aggregate principal amount of 11.375% Senior Notes due 2019 (the "11.375% Senior Notes"). The 11.375% Senior Notes are jointly and severally, and unconditionally, guaranteed (the "guarantees") on a senior unsecured basis initially by two of our wholly-owned subsidiaries, and all of our future subsidiaries other than immaterial subsidiaries (such guarantors, the "Guarantors"). The 11.375% Senior Notes and the guarantees were issued pursuant to an indenture dated as of February 9, 2011 (the "11.375% Senior Notes Indenture"), by and among the Company, the Guarantors party thereto and The Bank of New York Mellon Trust Company, N.A., a national banking association, as trustee (the "Trustee").

In December 2011, the Company entered into an exchange transaction related to the new Senior Secured Notes mentioned below. Approximately $198 million of the 11.375% Senior Notes were exchanged to new Senior Secured Notes. As a result of this transaction, the Company recognized a net gain of $6.7 million, included in gain (loss) on extinguishment of debt presented in the statements of operations. As of December 31, 2011, the net carrying amount of the 11.375% Senior Notes was as follows (amounts in thousands):

		2011
Principal amount	$	1,970
Unamortized debt discount		(58)
Carrying amount	$	1,912

As of December 31, 2011, unamortized debt issue costs were approximately $68,000.

The 11.375% Senior Notes bear interest at a rate of 11.375% per year, payable semiannually in arrears on February 15 and August 15 of each year, beginning August 15, 2011. As a result of the amortization of the debt discount through non-cash interest expense, the effective interest rate on the 11.375% Senior Notes is 12.94% per annum. The amount of the cash interest expense recognized with respect to the 11.375% contractual interest coupon for the year ended December 31, 2011 was $19.6 million. The amount of non-cash interest expense for the year ended December 31, 2011 related to the amortization of the debt discount and transaction costs was $1.2 million. As of December 31, 2011, the unamortized discount is expected to be amortized into earnings over 7.1 years.

The covenants were removed as part of the issuance of the Senior Secured Notes due 2017.

Senior Secured Notes

On December 19, 2011, the Company executed an indenture (the "Senior Secured Notes Indenture"), dated as of December 19, 2011, among the Company, the guarantors party thereto and U.S. Bank National Association, as trustee. On December 19, 2011, the Company issued $283,475,000 aggregate principal amount of Senior Secured Notes due 2017 (the "Senior Secured Notes") pursuant to the Senior Secured Notes Indenture. The Senior Secured Notes are fully and unconditionally guaranteed (the "Guarantees"), jointly and severally, on a senior secured basis by each of the Company's existing and future domestic restricted subsidiaries (the "Guarantors"). All of the Company's existing subsidiaries other than Endeavor Gathering, LLC are domestic restricted subsidiaries and Guarantors.

As of December 31, 2011, the net carrying amount of the Senior Secured Notes was as follows (amounts in thousands):

		2011
Principal amount	$	283,475
Unamortized debt discount		(8,064)
Carrying amount	$	275,411

As of December 31, 2011, unamortized debt issue costs were approximately $6.1 million which is included in other assets on the balance sheet.

Under the terms of the Senior Secured Notes Indenture, interest on the Senior Secured Notes will:

- accrue from the date of issuance of the Senior Secured Notes or, if interest has already been paid, from the most recent interest payment date;

- unless the Company elects to pay a portion of the interest in the form of additional notes (a "PIK Election") with respect to an interest period, accrue for such interest period at the rate of 11.0% per annum, payable in cash, in arrears;

- if the Company makes a PIK Election with respect to an interest period, accrue for such interest period at the rate of 13.0% per annum in the aggregate, of which (i) 9.0% per annum shall be payable in cash, in arrears, and (ii) 4.0% per annum shall be payable in the form of additional notes (in minimum denominations of $1,000 and integral multiples thereof, with any fractional additional notes being paid in cash), in arrears;

- be payable on each June 1 and December 1, commencing June 1, 2012, to holders of record of the Senior Secured Notes as of the May 15 and November 15 immediately preceding the relevant interest payment date; and

- be computed on the basis of a 360-day year comprised of twelve 30-day months.

The Senior Secured Notes will mature on December 1, 2017. The Senior Secured Notes will be secured by first-priority perfected liens on substantially all right, title and interest in or to substantially all of the assets and properties owned or acquired by the Company and the Guarantors (the "Collateral") The Collateral obligations are governed by, among other security documents, the Security Agreements.

The Senior Secured Notes are senior obligations of the Company and are secured by a first-priority perfected note lien on the Collateral (subject to certain permitted liens). The Senior Secured Notes rank senior in right of payment to all existing and future obligations of the Company that are expressly subordinated in right of payment to the Senior Secured Notes. The Senior Secured Notes rank pari passu to all unsubordinated obligations of the Company (though they will be effectively senior to any such obligations to the extent of the value of the collateral securing the obligations under the Senior Secured Notes). The Senior Secured Notes are effectively subordinated to all obligations of the Company that are subject to certain permitted liens (including, without limitation, certain letter of credit facilities and hedging obligations) ranking higher than the Senior Secured Notes to the extent of the value of the collateral securing such obligations or that are subject to a permitted lien that causes the assets subject to such lien to be excluded from the collateral. The Senior Secured Notes are also effectively subordinated to all obligations of any of Subsidiaries of the Company that do not guarantee the Senior Secured Notes.

The Senior Secured Notes Indenture restricts, among other things, the Company's and its restricted subsidiaries' ability to:

- incur or guarantee additional indebtedness or issue certain preferred stock;
- pay dividends or make other distributions;
- issue capital stock of our restricted subsidiaries;
- transfer or sell assets, including the capital stock of our restricted subsidiaries;
- make certain investments or acquisitions;
- grant liens on our assets;
- incur dividend or other payment restrictions affecting our restricted subsidiaries;
- enter into certain transactions with affiliates; and
- merge, consolidate or transfer all or substantially all of our assets.

The covenants are subject to important exceptions and qualifications.

If an event of default on the Senior Secured Notes has occurred and is continuing, the aggregate principal amount of the Senior Secured Notes, plus any accrued and unpaid interest and redemption premium, may be declared immediately due and payable at the trustee's discretion or upon request of at least 25% in principal amount of the outstanding Senior Secured Notes. These amounts automatically become due and payable upon the occurrence of certain bankruptcy events.

The Company may redeem any of the Senior Secured Notes, in whole or in part, at any time on or after December 1, 2014. Upon any such optional redemption, the Company will pay a redemption price equal to the following redemption prices (expressed as a percentage of principal amount of the Senior Secured Notes), plus accrued and unpaid interest on the Senior Secured Notes, if any, to, but not including, the applicable redemption date (subject to the right of holders of record on the relevant record date to receive interest due on the relevant interest payment date), if redeemed during the twelve-month period beginning on December 1 of the years indicated below:

Year	Percentage
2014	105.500 %
2015	102.750 %
2016 and thereafter	100.000 %

The Company will give not less than 30 nor more than 60 days notice of any such redemption.

At any time prior to December 1, 2014 the Company may, at its option, on any one or more occasions redeem up to 35% of the aggregate principal amount of the Senior Secured Notes (including Additional Notes but without duplication for exchange notes) originally issued under the Senior Secured Notes Indenture with the net cash proceeds of one or more equity offerings at a redemption price of 111.0% of the aggregate principal amount thereof, plus accrued and unpaid interest, if any, additional interest, if any, to, but not including, the redemption date (subject to the right of holders of record on the relevant record date to receive interest due on the relevant interest payment date); provided that (1) at least 65% of the original principal amount of the Senior Secured Notes originally issued under the Senior Secured Notes Indenture (including Additional Notes but without duplication for exchange notes) remains outstanding after each such redemption; and (2) the redemption occurs within 90 days after the closing of the related Equity Offering.

In addition, the Senior Secured Notes may be redeemed, in whole or in part, at any time prior to December 1, 2014 at the option of the Company upon not less than 30 nor more than 60 days' prior notice mailed by first-class mail to each holder of Notes at its registered address, at a redemption price equal to 100% of the principal amount of the Notes redeemed, plus an "Applicable Premium" as of, and accrued and unpaid interest to, but not including, the applicable redemption date (subject to the right of holders of record on the relevant record date to receive interest due on the relevant interest payment date).

If a Change of Control (as defined in the Senior Secured Notes Indenture) occurs, we must offer to repurchase the Senior Secured Notes at 101% of their principal amount, plus accrued and unpaid interest.

In addition, in connection with certain Asset Dispositions (as defined in the Senior Secured Notes Indenture), we must offer to repurchase the Senior Secured Notes with the proceeds of such Asset Dispositions within 30 days.

Joint Venture Financing

In 2004, we entered into an arrangement with PVOG to purchase dollar denominated production payments from the Company on certain wells drilled during a portion of 2004. Under this agreement, PVOG provided $2.8 million in funding for our share of costs of four wells drilled which is repayable solely from 75% of GMX's share of production revenues from these wells without interest.

NOTE G—ASSET RETIREMENT OBLIGATIONS

The activity incurred in the asset retirement obligation is as follows:

	2011	2010
	(in thousands)	
Beginning balance	$ 7,278	$ 6,789
Liabilities incurred	119	269
Liabilities settled	(407)	(467)
Accretion	436	412
Revisions	300	275
Ending balance(1)	7,726	7,278
Less current portion(1)	360	406
	$ 7,366	$ 6,872

(1) The Company's liability for asset retirement obligations is included in other liabilities in the consolidated balance sheets, net of the current obligations. The current portion is included in accrued expenses in the consolidated balance sheets.

NOTE H—INCOME TAXES

Income tax expense (benefit) consists of the following for the years ended December 31:

	2011	2010	2009 (as adjusted)
		(in thousands)	
Current tax expense (benefit)	$ —	$ (30)	$ (33)
Deferred tax expense (benefit)	615	(4,209)	—
	$ 615	$ (4,239)	$ (33)

Total income tax expense (benefit) differed from the amounts computed by applying the U.S. federal tax rate to earnings before income taxes as a result of the following for the years ended December 31:

	2011	2010	2009
		(in thousands)	
U.S. statutory tax rate	34 %	34 %	34 %
Statutory depletion	— %	3 %	— %
Change in valuation allowance	(33)%	(37)%	(33)%
Other	(1)%	3 %	(1)%
Effective income tax rate	— %	3 %	— %

Intangible development costs may be capitalized or expensed for income tax reporting purposes, whereas they are capitalized and amortized for financial statement purposes. Lease and well equipment and other property and equipment may be depreciated for income tax reporting purposes using accelerated methods and different lives. Other temporary differences include the effect of hedging transactions and stock based compensation awards. Deferred income taxes are provided on these temporary differences to the extent that income taxes which otherwise would have been payable are reduced. Deferred income tax assets are also available to offset future income taxes.

The following table sets forth the Company's deferred tax assets and liabilities at December 31:

	2011	2010	2009 (as adjusted)
		(in thousands)	
Deferred tax assets:			
Federal net operating loss carryforwards	$ 112,990	$ 71,911	$ 26,500
Property and equipment	7,944	10,644	548
Statutory depletion carryforwards	5,813	5,723	2,245
Stock compensation expense	2,513	1,416	1,030
Derivative instruments	—	704	662
Oil and natural gas properties	101,688	56,992	60,089
Other	33	480	431
Valuation allowance on deferred tax assets not expected to be realized	(202,225)	(133,451)	(79,182)
Total	28,756	14,419	12,323
Deferred tax liabilities:			
Derivative instruments	(7,227)	(8,066)	(4,237)
Convertible debt and share lending agreement	(4,389)	(6,353)	(8,086)
Volumetric production payment	(16,519)	—	—
Bond issuance costs	(621)	—	—
Total	(28,756)	(14,419)	(12,323)
Net deferred tax asset (liability)	$ —	$ —	$ —

The valuation allowance for deferred tax assets increased by $68.7 million in 2011. In determining the carrying value of a deferred tax asset, accounting standards provides for the weighing of evidence in estimating whether and how much of a deferred tax asset may be recoverable. As we have incurred net operating losses in 2011 and prior years, relevant accounting guidance suggest that cumulative losses in recent years constitute significant negative evidence, and that future expectations about income are insufficient to overcome a history of such losses. Therefore, with the before mentioned adjustment of $68.7 million, we continue to reduce the carrying value of our net deferred tax asset to zero for 2011, which has been the case in prior years. The valuation allowance has no impact on our net operating loss ("NOL") position for tax purposes, and if we generate taxable income in future periods, we will be able to use our NOLs to offset taxes due at that time. The Company will continue to assess the valuation allowance against deferred tax assets considering all available evidence obtained in future reporting periods.

At December 31, 2011, the Company had federal net operating loss carryforwards of $332.3 million which will begin to expire in 2018 if unused. The Company's federal net operating loss carryforward has an annual limitation under Internal Revenue Code Section 382. In addition, at December 31, 2011, the Company had tax percentage depletion carryforwards of approximately $17.1 million which are not subject to expiration.

The Company and its subsidiaries file income tax returns in the U.S. federal jurisdiction and in various states. With few exceptions, the Company is no longer subject to U.S. federal or state income tax examinations by these tax authorities for years before and including 2007. We have not paid any significant interest or penalties associated with our income taxes, but classify both interest expense and penalties as part of our income tax expense.

NOTE I—COMMITMENTS AND CONTINGENCIES

Legal Matters

A putative class action lawsuit was filed by the Northumberland County Retirement System and Oklahoma Law Enforcement Retirement System in the District Court in Oklahoma County, Oklahoma, purportedly on March 10, 2011, against the Company and certain of its officers along with certain underwriters of the Company's July 2008, May 2009 and October 2009 public offerings. Discovery requests and summons were filed and issued, respectively, in late April 2011. The complaint alleges that the registration statement and the prospectus for the offering contained material misstatements and omissions and seek damages under Sections 11, 12 and 15 of the Securities Act of 1933 of an unspecified equitable relief. Defendants removed the case to federal court on May 12, 2011 and filed motions to dismiss on June 20, 2011. Plaintiffs filed a motion to remand the case to state court on June 10, 2011, and Defendants filed an opposition to that motion. By order dated November 16, 2011, the court denied Plaintiffs' motion to remand. On February 3, 2012, Plaintiffs moved to be appointed lead plaintiff under the Private Securities Litigation Reform Act. After the appointment of lead plaintiff, Plaintiffs are expected to file an amended complaint, with Defendants' responses thereto expected to be filed in early June 2012. We are currently unable to assess the probability of loss or estimate a range of potential loss, if any, associated with the securities class action case, which is at an early stage.

On August 5, 2011, an individual filed a shareholders' derivative action in the United States District Court for the Western District of Oklahoma, for the Company's benefit, as nominal defendant, against the Company's Chief Executive Officer, President, Chief Financial Officer, and certain members of the Company's board of directors. The complaint alleges breaches of fiduciary duty, waste of corporate assets, and unjust enrichment on the part of each of the named defendants and is premised on substantially the same facts alleged in the above-described securities lawsuit. The complaint seeks unspecified amounts of compensatory damages, implementation of certain corporate governance changes, and disgorgement of compensation and trading profits from the individual defendants, as well as interest and costs, including legal fees from the defendants. The Company is a nominal defendant, and the complaint does not seek any damages against the Company; however, the Company may have indemnification obligations to one or more of the defendants under the Company organizational documents. On October 17, 2011, the individual defendants and the Company as nominal defendant filed motions to dismiss the complaint for failure to make demand, or in the alternative, to stay the derivative action pending the outcome of the securities lawsuit. The case is currently stayed pending the outcome of the motions to dismiss that are expected to be filed with respect to the securities lawsuit described above.

On February 7 and 9, 2012, two individuals filed separate shareholder derivative actions in the District Court of Oklahoma County, in the State of Oklahoma, for the Company's benefit, as nominal defendant, against the Company's Chief Executive Officer, President, Chief Financial Officer, and each member of the Company's board of directors. The petitions assert claims similar to those asserted in the federal court derivative action described above. Plaintiffs recently filed a motion to consolidate the two state court derivative actions, and the court consolidated the two actions. The parties are conferring about the schedule for the filing of an amended petition and defendants' responses thereto.

The Company is party to various legal actions arising in the normal course of business. Matters that are probable of unfavorable outcome to the Company and which can be reasonably estimated are accrued. Such accruals are based on information known about the matters, the Company's estimates of the outcomes of such matters, and its experience in contesting, litigating, and settling similar matters. None of the actions are believed by management to involve future amounts that would be material to the Company's financial position or results of operations after consideration of recorded accruals.

Lease Obligations

The Company leases offices and certain equipment under operating leases and has contracts with a drilling contractor for the use of one rig with a one year term. Additionally, in 2010, the Company entered into a firm transportation and a firm sales contract for various terms through 2020. Under these contracts, the Company is obligated to transport or sell minimum daily gas volumes, as calculated on a monthly basis, or pay for any deficiencies, at a set rate. The firm transportation contract for 50 Mmbtu per day commences with the completion of a pipeline which occurred in the first quarter of 2010. An additional sales contract was effective in September 2009 for 15 Mmbtu per day and increases through 2014 up to 100 Mmbtu per day. These commitments are not recorded in the accompanying consolidated balance sheets.

The following is schedule by year of these obligations and minimum lease payments at December 31, 2011:

Year	Operating Leases	Transportation	Drilling Contracts	Total
		(in thousands)		
2012	$ 1,632	$ 6,190	$ 13,797	$ 21,619
2013	1,130	6,353	1,106	8,589
2014	708	5,970	—	6,678
2015	778	5,668	—	6,446
2016	726	5,668	—	6,394
Thereafter	95	17,003	—	17,098
Total	$ 5,069	$ 46,852	$ 14,903	$ 66,824

Rent expense on operating leases for the years ended December 31, 2011, 2010 and 2009 was $3.2 million, $2.8 million and $1.4 million, respectively.

NOTE J—STOCK COMPENSATION PLANS

We recognized $4.3 million, $6.6 million and $5.8 million of stock compensation expense for the years ending December 31, 2011, 2010 and 2009, respectively. These non-cash expenses are reflected as a component of the Company's general and administrative expense. To the extent amortization of compensation costs relates to employees directly involved in exploration and development activities, such amounts are capitalized to oil and natural gas properties. Stock based compensation capitalized as part of oil and natural gas properties was $0.6 million $1.0 million and $1.2 million for the years ended December 31, 2011, 2010 and 2009, respectively.

2008 Long-Term Incentive Plan

In May 2008, the Board of Directors and shareholders adopted the 2008 Long-Term Incentive Plan (or "LTI Plan") to retain and attract employees, consultants and directors, and to stimulate the active interest in the development and financial success of the Company. The LTI Plan provides for the grant of stock options, restricted stock awards, bonus stock awards, stock appreciation rights, performance units and performance bonuses, subject to certain conditions.

On June 17, 2010, the LTI Plan was amended. Under the terms of the amended LTI Plan, the aggregate number of shares of common stock available for awards may not exceed 1,750,000 shares. Of the shares available for issuance under the LTI Plan as of the amendment date of the LTI Plan, 750,000 could be granted as "incentive stock options" as defined in Section 422 of the Internal Revenue Code of 1986, as amended (the "Code").

2000 Stock Option Plan

In October 2000, the Board of Directors and shareholders adopted the GMX Resources Inc. Stock Option Plan (the "2000 Option Plan"). Under the 2000 Option Plan, the Company may grant both stock options intended to qualify as incentive stock options under Section 422 of the Internal Revenue Code and options which are not qualified as incentive stock options.

The maximum number of shares of common stock issuable under the 2000 Option Plan, as amended in May 2007, is 850,000, subject to appropriate adjustment in the event of reorganization, stock split, stock dividend, reclassification or other change affecting the Company's common stock. All officers, employees and directors are eligible to receive awards under the 2000 Option Plan. The exercise price of options granted is not less than 100% of the fair market value of the shares on the date of grant. Options granted become exercisable as the Board of Directors may determine in connection with the grant of each option. In addition, the Board of Directors may at any time accelerate the date that any option granted becomes exercisable. Stock options generally vest over four years and have a 10-year contractual term. 25,698 options were accelerated in vesting during 2010 as a result of agreements with terminated employees. There have been no options for which vesting was accelerated in 2011 and 2009.

The 2000 Option Plan terminated on October 30, 2010, and no options will be granted pursuant to this plan except with respect to awards then outstanding.

Stock Options

The following table provides information related to stock option activity under the 2000 Option Plan for the years ended December 31, 2009, 2010 and 2011:

	Number of shares underlying options	Weighted average exercise price per share	Aggregate intrinsic value[(1)] (in thousands)	Weighted average grant date fair value per share
Outstanding as of December 31, 2008	583,050	$ 30.16		
Exercised	(750)	6.10	$ 3	
Forfeited	(5,500)	33.95		
Outstanding as of December 31, 2009	576,800	30.16		
Granted	48,001	6.34		4.36
Forfeited	(48,750)	32.84		
Outstanding as of December 31, 2010	576,051	27.93		
Forfeited	(114,000)	31.56		
Expired	(2,500)	5.00		
Outstanding as of December 31, 2011	459,551	$ 27.17	$ —	
Exercisable as of December 31, 2011	409,389	$ 29.15	$ —	

(1) The intrinsic value is the amount by which the market value of the underlying stock exceeds the exercise price.

The weighted-average remaining contractual life of outstanding and exercisable options at December 31, 2011 was 4.9 years. As of December 31, 2011 there was $133,186 of total unrecognized compensation costs related to non-vested stock options granted under the Company's stock option plan. That cost is expected to be recognized over a weighted average period 2.3 years.

The fair value of each stock award is estimated on the date of grant using the Black-Scholes option pricing model. Assumptions used in the valuation are disclosed in the following table:

	2011	2010	2009
Expected volatility	—%	77.2%	—%
Expected dividend yields	—%	—%	—%
Expected term (in years)	—	6.25	—
Risk free rate	—%	2.2%	—%

The Company estimated volatility is based on the historical volatility of the Company's common stock. The risk free interest rate is based on the U. S. Treasury yield curve in effect at the time of grant for the expected term of the option. The expected dividend yield is based on the Company's current dividend yield and the best estimate of projected dividend yield for future periods within the expected life of the option.

Restricted Stock

In July 2008, the Company began issuing restricted stock awards to its officers, independent directors, consultants and certain employees under the LTI Plan. The holders of these shares have all the rights and privileges of owning the shares (including voting rights) except that the holders are not entitled to delivery of a portion thereof until certain passage of time requirements are met. With respect to the restricted stock granted to officers, consultants, and employees of the Company, the shares generally vest over a three or four year period. With respect to restricted shares issued to the Company's independent board members, the shares vest over a two-year period. The fair value of the awards issued is determined based on the fair market value of the shares on the date of grant. The value is amortized over the vesting period. In 2011 and 2010, 914 and 74,799 restricted shares, respectively, accelerated vesting as a result of termination agreements with employees.

A summary of the status of our unvested shares of restricted stock and the changes for the years ending December 31, 2009, 2010 and 2011 is presented below:

	Number of unvested restricted shares	Weighted average grant-date fair value per share
Unvested shares as of December 31, 2008	62,728	$ 73.44
Granted	542,847	$ 18.55
Vested	(23,574)	$ 70.38
Forfeited	(1,471)	$ 29.00
Unvested shares as of December 31, 2009	580,530	$ 22.35
Granted	359,385	$ 6.34
Vested	(220,016)	$ 24.21
Forfeited	(27,903)	$ 23.11
Unvested shares as of December 31, 2010	691,996	$ 13.47
Granted	807,848	$ 4.79
Vested	(245,924)	$ 16.46
Forfeited	(5,521)	$ 19.42
Unvested shares as of December 31, 2011	1,248,399	$ 7.24

As of December 31, 2011, there was $7.1 million of unrecognized compensation expense related to non-vested restricted stock grants. This unrecognized compensation cost is expected to be recognized over a weighted-average period of 2.0 years.

The vesting of certain restricted stock grants results in state and federal income tax benefits related to the difference between the market price of the common stock at the date of vesting and the date of grant. During the years ended December 31, 2011 and 2010, we did not recognize excess tax benefits related to the vesting of restricted stock due to the market price of the common stock at the date of grant exceeding the market price at the vesting date.

401(k) Plan

The GMX Resources Inc. 401(k) Plan was adopted April 15, 2001. The plan is a qualified retirement plan under the Internal Revenue Code. All employees are eligible who have attained age 21. GMX matches the employee contributions up to 5% of the employee's gross wages. The Company contributed $497,340, $449,000 and $281,000 in 2011, 2010 and 2009, respectively.

NOTE K—CAPITAL STOCK

Common stock:

In May 2009, GMX completed an offering of 5,750,000 shares of its common stock for $12.00 per share. Net proceeds to the Company were $65.3 million. The Company used the net proceeds from this offering to repay outstanding indebtedness under its revolving bank credit facility.

In October 2009, GMX completed an offering of 6,950,000 shares of its common stock at $15.00 per share. Net proceeds to the Company were approximately $98.8 million. The Company used the net proceeds from this offering, along with the proceeds from the concurrent issuance of the 4.50% Convertible Notes, to repay the outstanding indebtedness under its revolving bank credit facility and to repay all of its outstanding senior subordinated secured notes, and for general corporate purposes.

As mentioned in "Note F—Long-Term Debt," in December 2010, the Company converted $2.25 million of the 5.00% Convertible Notes for a combined total of 380,250 shares of the Company's common stock.

In February 2011, GMX completed an offering of 21,075,000 shares of its common stock at a price of $4.75 per share. The net proceeds to the Company were $93.6 million after discounts and underwriters' fees. In March 2011, the underwriters exercised the over-allotment option granted in connection with the February 2011 offering and purchased an additional 1,098,518 shares of common stock, which increased the net proceeds to the Company by $4.9 million after discounts and underwriters' fees. The Company used the net proceeds, together with proceeds from a concurrent private placement of the 11.375% Senior Notes, to (i) fund an offer to purchase up to $50.0 million of its 5.00% convertible notes, (ii) repay the then outstanding balance under its secured revolving credit facility (iii) fund the cash portion of the purchase price of the acquisitions described in Note A and (iv) used the remaining net proceeds to fund its exploration and development program and for other general corporate purposes.

In February 2011, the Company issued 2,268,971 common shares in connection with the Bakken acquisition described in Note A. In April 2011, the Company issued an additional 3,542,091 shares of its common stock in connection with another set of Bakken acquisitions also described in Note A.

On December 19, 2011, the Company issued 3,877,254 shares of the Company's common stock pursuant to support agreements with each of the supporting holders in connection with the consummation of an exchange offer and consent solicitation for the Company's outstanding $200,000,000 11.375% Senior Notes, pursuant to which holders tendering in the exchange offer received new Senior Secured Notes.

Preferred stock:

For the year ended December 31, 2010, the Company received $0.9 million related to the issuance of 41,169 shares of its 9.25% Series B Cumulative Preferred Stock in ongoing at-the-market sales by the Company.

For the year ended December 31, 2011, the Company received $25.8 million related to the issuance of 1,135,565 shares of its 9.25% Series B Cumulative Preferred Stock in ongoing at-the-market sales by the Company.

The annual dividends on each share of Series B Cumulative Preferred Stock are $2.3125 and is payable quarterly when, as and if declared by GMX, in cash (subject to specified exceptions), in arrears to holders of record as of the dividend payment record date, on or about the last calendar day of each March, June, September and December.

The Series B Cumulative Preferred Stock is not convertible into the GMX's common stock and can be redeemed at the Company's option at $25.00 per share. The Series B Cumulative Preferred Stock will be required to be redeemed at $25.00 per share in the event of a change of ownership or control of GMX if the acquirer is not a public company meeting certain financial criteria. The Company has not exercised its option to redeem any shares for the year ended December 31, 2011.

NOTE L—OIL AND NATURAL GAS OPERATIONS

Costs incurred in oil and natural gas property acquisitions, exploration, and development activities are as follows for the years ended December 31:

	2011	2010	2009
		(in thousands)	
Development and exploration costs:			
Development drilling	$ 80,305	$ 7,788	$ 14,202
Exploratory drilling	42,479	164,355	116,250
Tubular and other drilling inventories	1,068	3,167	1,697
Asset retirement obligation	418	706	565
	124,270	176,016	132,714
Acquisition:			
Proved	4,893	3,884	6,881
Unproved[(1)]	153,059	8,149	11,450
	157,952	12,033	18,331
Total	$ 282,222	$ 188,049	$ 151,045

(1) Includes $7.8 million, $2.6 million and $1.8 million of capitalized interest for the years ended December 31, 2011, 2010 and 2009, respectively.

Costs excluded from amortization are as follows at December 31:

	2011	2010
	(in thousands)	
Unproved property acquisition	$ 147,224	$ 37,006
Exploratory drilling	—	2,688
	$ 147,224	$ 39,694

Unproved property acquisition costs include costs to acquire new leasehold, unevaluated leaseholds, and capitalized interest. Of the $147.2 million of unproved property costs at December 31, 2011 being excluded from the amortization base, $139.0 million, $4.5 million and $3.7 million were incurred in 2011, 2010 and in the years 2009 and prior, respectively. Subject to industry conditions, evaluation of most of these properties and the inclusion of their costs in the amortized capital costs is expected to be completed within ten years based on development activity and extension of leases as allowed under the terms of the lease agreements.

The average DD&A rate per equivalent unit of production was $1.88, $1.88 and $1.76 for the years ended December 31, 2011, 2010 and 2009, respectively.

NOTE M—SUPPLEMENTAL INFORMATION ON OIL AND NATURAL GAS OPERATIONS (UNAUDITED)

In December 2008, the SEC issued its final rule, Modernization of Oil and Gas Reporting, which was effective for reporting 2009 and subsequent periods reserve information. In January 2010, the FASB issued its authoritative guidance on extractive activities for oil and gas to align its requirements with the SEC's final rule. We adopted the guidance as of December 31, 2009 in conjunction with our year-end reserve report as a change in accounting principle that is inseparable from a change in accounting estimate. The primary impacts in 2009 of the SEC's final rule included:

- the use of the 2009 twelve-month average of the first-day-of-the-month reference prices (prior to adjustment for location and quality differentials) of $61.18 per Bbl for oil and $3.87 per MMBtu for natural gas compared to the year-end 2009 reference prices (prior to adjustment for location and quality differentials) of $79.36 per Bbl for oil and $5.79 per MMBtu for natural gas resulted in negative revisions of 16 Bcfe;
- certain of our undeveloped locations are not scheduled to be developed within five years of December 31, 2009, had the impact of reducing our proved undeveloped reserves by 25 Bcfe; and
- applying the same pricing methodology that was in effect for 2008 in 2009 would have resulted in the recognition of an additional 99 Bcfe in reserves at December 31, 2009.

In addition to the 2009 pricing discussed above, the twelve month average of the first-day-of-the-month reference prices (prior to adjustment for location and quality differentials) for 2011 and 2010 were $96.19 and $79.43, respectively, per Bbl for oil and $4.12 and $4.38, respectively, per MMBtu for natural gas.

All of our reserves were located in the United States. Our reserves were based upon reserve reports prepared by the independent petroleum engineers of MHA Petroleum Consultants, Inc. ("MHA") and DeGolyer and MacNaughton ("D&M"). Management believes the reserve estimates presented herein, in accordance with generally accepted engineering and evaluation principles consistently applied, are reasonable. However, there are numerous uncertainties inherent in estimating quantities and values of proved reserves and in projecting future rates of production and the amount and timing of development expenditures, including many factors beyond our control. Reserve engineering is a subjective process of estimating the recovery from underground accumulations of oil and gas that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Because all reserve estimates are to some degree speculative, the quantities of oil and gas that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures and future oil and gas sales prices may all differ from those assumed in these estimates. In addition, different reserve engineers may make different estimates of reserve quantities and cash flows based upon the same available data.

Therefore, the Standardized Measure shown below represents estimates only and should not be construed as the current market value of the estimated oil and gas reserves attributable to our properties. In this regard, the information set forth in the following tables includes revisions of reserve estimates attributable to proved properties included in the preceding year's estimates. Such revisions reflect additional information from subsequent development activities, production history of the properties involved and any adjustments in the projected economic life of such properties resulting from changes in product prices. Decreases in the prices of oil and natural gas have had, and could have in the future, an adverse effect on the carrying value of our proved reserves, reserve volumes and our revenues, profitability and cash flow.

As of December 31, 2011 and 2010, our reserves shown are net wellhead volumes that have been reduced for lease use volumes (volumes that are consumed or lost between the wellhead and the point of custody transfer). Prior to December 31, 2010, wellhead volumes had not been reduced for lease use volumes which were estimated to be 11% of ending proved reserves as of December 31, 2009.

Estimated Quantities of Oil and Natural Gas

The following table sets forth certain data pertaining to our proved, proved developed and proved undeveloped reserves for the three years ended December 31, 2011.

	OIL (MBBLS)	GAS (MMCF)
December 31, 2009		
Proved reserves, beginning of period	5,004	435,321
Extensions, discoveries, and other additions	38	25,672
Production	(119)	(12,908)
Revisions of previous estimates	(1,244)	(114,873)
Proved reserves, end of period	3,679	333,212
December 31, 2010		
Proved reserves, beginning of period	3,679	333,212
Extensions, discoveries, and other additions	—	232,629
Production	(95)	(16,901)
Revisions of previous estimates	(2,363)	(236,991)
Proved reserves, end of period	1,221	311,949
December 31, 2011		
Proved reserves, beginning of period	1,221	311,949
Extensions, discoveries, and other additions	919	6,681
Production	(93)	(22,958)
Sales of reserves-in-place	—	(14,750)
Revisions of previous estimates	(319)	(6,009)
Proved reserves, end of period	1,728	274,913
Proved Developed Reserves		
December 31, 2008	1,920	150,585
December 31, 2009	1,439	124,611
December 31, 2010	1,221	157,027
December 31, 2011	1,256	155,133
Proved Undeveloped Reserves		
December 31, 2008	3,084	284,736
December 31, 2009	2,240	208,601
December 31, 2010	—	154,922
December 31, 2011	472	119,780

Revisions of Previous Estimates

In 2009, we had negative revisions of 122 Bcfe. Certain of our Cotton Valley Sands undeveloped locations are scheduled for development beyond five years and were excluded from our proved reserves, resulting in a negative revision of 53 Bcfe. The proved reserves for Cotton Valley Sands producers were reduced by 53 Bcfe based on individual well production history. Negative revisions of 16 Bcfe were related to lower natural gas prices as declines in prices result in certain reserves becoming uneconomic at earlier periods.

In 2010, we had negative revisions of 251 Bcfe, which was primarily the result of all of our Cotton Valley Sands undeveloped locations being removed for adherence with the SEC five-year guideline for booking our proved reserves, resulting in a negative revision of 219.6 Bcfe. In addition to the Cotton Valley Sands undeveloped locations, the Company also had negative revisions of 10.2 Bcfe related to individual well production history and 16.2 Bcfe related to reporting reserves at net well head volumes.

In 2011, we had negative revisions of 8 Bcfe, which was primarily the result of decreases in natural gas prices and changes in estimated production for existing wells.

Extensions, Discoveries and Other Additions

In 2009, we had a total of 25 Bcfe of extensions and discoveries, including 22 Bcfe in the Haynesville Shale resulting from successful drilling during 2009 that extended and developed the proved acreage.

In 2010, we had a total of 233 Bcfe of extensions and discoveries in the Haynesville Shale resulting from successful drilling during 2010 that extended and developed the proved acreage.

In 2011, we had a total of 12 Bcfe of extensions and discoveries. This primarily related to our successful drilling in the Bakken.

Standardized measure of discounted future net cash flows

The Standardized Measure of discounted future net cash flows (discounted at 10%) from production of proved reserves was developed as follows:

- An estimate was made of the quantity of proved reserves and the future periods in which they are expected to be produced based on year-end economic conditions.
- In accordance with SEC guidelines, the engineers' estimates of future net revenues from our proved properties and the present value thereof are made using the twelve-month average of the first-day-of-the-month reference prices as adjusted for location and quality differentials. These prices are held constant throughout the life of the properties. Oil and natural gas prices are adjusted for each lease for quality, contractual agreements, and regional price variations.
- The future gross revenue streams were reduced by estimated future operating costs (including production and ad valorem taxes) and future development and abandonment costs, all of which were based on current costs in effect at December 31 of the year presented and held constant throughout the life of the properties.
- Future income taxes were calculated by applying the statutory federal and state income tax rate to pre-tax future net cash flows, net of the tax basis of the properties involved and utilization of available tax carryforwards related to oil and gas operations.

The following summary sets forth the Company's future net cash flows relating to proved oil and natural gas reserves based on the standardized measure as of December 31:

	2011	2010	2009
		(in thousands)	
Future cash inflows	$ 1,266,504	$ 1,381,031	$ 1,540,047
Future production costs	(390,131)	(401,387)	(591,102)
Future development costs	(256,794)	(286,897)	(323,246)
Future income tax provisions	—	—	—
Net future cash inflows	619,579	692,747	625,699
Less effect of a 10% discount factor	(432,980)	(442,857)	(437,121)
Standardized measure of discounted future net cash flows	$ 186,599	$ 249,890	$ 188,578

Principal changes in the standardized measure of discounted future net cash flows attributable to the Company's proved reserves are as follows for the years ended December 31:

	2011	2010	2009
		(in thousands)	
Standardized measure, beginning of year	$ 249,890	$ 188,578	$ 228,793
Sales of oil and natural gas, net of production costs	(83,315)	(62,847)	(45,233)
Net changes in prices and production costs	(33,584)	164,062	(135,218)
Change in estimated future development costs	(4,176)	300,915	76,929
Extensions and discoveries, net of future development costs	14,595	113,367	60,206
Previously estimated development cost incurred	66,311	5,761	143,316
Sales of reserves-in-place	(45,507)	—	—
Revisions of quantity estimates	(4,276)	(260,272)	(82,836)
Accretion of discount	75,260	68,045	83,475
Changes in timing of production and other	(48,599)	(267,719)	(192,723)
Net changes in income taxes	—	—	51,869
Standardized measure, end of year	$ 186,599	$ 249,890	$ 188,578

NOTE N—CONDENSED CONSOLIDATING FINANCIAL INFORMATION

Shown below are condensed consolidating financial statements for GMX Resources Inc. on a stand-alone, unconsolidated basis, its combined guarantor subsidiaries and its non-guarantor subsidiary as of December 31, 2011 and 2010 and the years ended December 31, 2011, 2010 and 2009. The financial information may not necessarily be indicative of results of operations, cash flows or financial position had the subsidiaries operated as independent entities.

Condensed Consolidating Balance Sheets

	December 31, 2011				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
			(In thousands)		
ASSETS					
CURRENT ASSETS					
Cash and cash equivalents	$ 98,118	$ 3,672	$ 703	$ —	$ 102,493
Restricted cash	4,325	—	—	—	4,325
Accounts receivable – interest owners	8,607	—	—	—	8,607
Accounts receivable – oil and natural gas revenues, net	12,564	295	—	(5,777)	7,082
Accounts receivable - intercompany	15,205	13,033	790	(29,028)	—
Inventories	326	—	—	—	326
Prepaid expenses and deposits	2,574	2	79	—	2,655
Assets held for sale	1,999	46	—	—	2,045
Total current assets	143,718	17,048	1,572	(34,805)	127,533
OIL AND NATURAL GAS PROPERTIES, BASED ON THE FULL COST METHOD					
Properties being amortized	1,061,961	713	127	—	1,062,801
Properties not subject to amortization	147,224	—	—	—	147,224
Less accumulated depreciation, depletion, and impairment	(871,346)	—	—	—	(871,346)
	337,839	713	127	—	338,679
PROPERTY AND EQUIPMENT, AT COST, NET	15,531	5,216	45,111	—	65,858
OTHER ASSETS	10,131	—	—	—	10,131
INVESTMENT IN SUBSIDIARIES	35,980	—	—	(35,980)	—
TOTAL ASSETS	$ 543,199	$ 22,977	$ 46,810	$ (70,785)	$ 542,201
LIABILITIES AND EQUITY					
CURRENT LIABILITIES					
Accounts payable	13,527	—	23	—	13,550
Accounts payable - intercompany	13,126	15,684	218	(29,028)	—
Accrued expenses	17,263	6,056	293	(5,777)	17,835
Accrued interest	3,256	—	—	—	3,256
Revenue distributions payable	5,980	—	—	—	5,980
Current maturities of long-term debt	26	—	—	—	26
Total current liabilities	53,178	21,740	534	(34,805)	40,647
LONG-TERM DEBT, LESS CURRENT MATURITIES	426,805	—	—	—	426,805
OTHER LIABILITIES	7,476	—	—	—	7,476
EQUITY					
Total GMX equity	55,740	1,237	46,276	(47,513)	55,740
Noncontrolling interest	—	—		11,533	11,533
Total equity	55,740	1,237	46,276	(35,980)	67,273
TOTAL LIABILITIES AND EQUITY	$ 543,199	$ 22,977	$ 46,810	$ (70,785)	$ 542,201

	December 31, 2010				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
			(In thousands)		
ASSETS					
CURRENT ASSETS					
Cash and cash equivalents	$ 1,468	$ 564	$ 325	$ —	$ 2,357
Accounts receivable – interest owners	5,338	—	1	—	5,339
Accounts receivable – oil and natural gas revenues, net	6,463	366	—	—	6,829
Accounts receivable - intercompany	15,450	4,195	1,786	(21,431)	—
Derivative instruments	19,486	—	—	—	19,486
Inventories	326	—	—	—	326
Prepaid expenses and deposits	5,532	149	86	—	5,767
Assets held for sale	1,085	16,817	8,716	—	26,618
Total current assets	55,148	22,091	10,914	(21,431)	66,722
OIL AND NATURAL GAS PROPERTIES, BASED ON THE FULL COST METHOD					
Properties being amortized	937,858	713	130	—	938,701
Properties not subject to amortization	39,694	—	—	—	39,694
Less accumulated depreciation, depletion, and impairment	(630,632)	—	—	—	(630,632)
	346,920	713	130	—	347,763
PROPERTY AND EQUIPMENT, AT COST, NET	15,879	5,518	47,640	—	69,037
DERIVATIVE INSTRUMENTS	17,484	—	—	—	17,484
OTHER ASSETS	6,084	—	—	—	6,084
INVESTMENT IN SUBSIDIARIES	48,773	—	—	(48,773)	—
TOTAL ASSETS	$ 490,288	$ 28,322	$ 58,684	$ (70,204)	$ 507,090
LIABILITIES AND EQUITY					
CURRENT LIABILITIES					
Accounts payable	24,635	—	284	—	24,919
Accounts payable - intercompany	5,533	15,331	567	(21,431)	—
Accrued expenses	32,796	116	136	—	33,048
Accrued interest	3,317	—	—	—	3,317
Revenue distributions payable	4,839	—	—	—	4,839
Current maturities of long-term debt	26	—	—	—	26
Total current liabilities	71,146	15,447	987	(21,431)	66,149
LONG-TERM DEBT, LESS CURRENT MATURITIES	284,943	—	—	—	284,943
DEFERRED PREMIUMS ON DERIVATIVE INSTRUMENTS	10,622	—	—	—	10,622
OTHER LIABILITIES	7,157	—	—	—	7,157
EQUITY					
Total GMX equity	116,420	12,875	57,697	(70,572)	116,420
Noncontrolling interest	—	—	—	21,799	21,799
Total equity	116,420	12,875	57,697	(48,773)	138,219
TOTAL LIABILITIES AND EQUITY	$ 490,288	$ 28,322	$ 58,684	$ (70,204)	$ 507,090

Condensed Consolidating Statements of Operations

	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
			(In thousands)		
Year Ended December 31, 2011					
TOTAL REVENUES	$ 114,841	$ 2,862	$ 11,365	$ (12,327)	$ 116,741
EXPENSES					
Lease operations	19,408	3,744	1,874	(11,606)	13,420
Production and severance taxes	1,196	—	—	—	1,196
Depreciation, depletion, and amortization	47,047	728	2,495	—	50,270
Impairment of oil and natural gas properties and assets held for sale	196,945	8,156	653	—	205,754
General and administrative	27,485	1,840	259	(721)	28,863
Total expenses	292,081	14,468	5,281	(12,327)	299,503
Income (loss) from operations	(177,240)	(11,606)	6,084	—	(182,762)
NON-OPERATING INCOME (EXPENSE)					
Interest expense	(31,873)	—	(2)	—	(31,875)
Gain (loss) on extinguishment of debt	4,987	—	—	—	4,987
Interest and other income (expense)	236	—	(31)	—	205
Gain (loss) on derivatives	3,612	—	—	—	3,612
Equity income (loss) of subsidiaries	(10,944)			10,944	—
Total non-operating expense	(33,982)	—	(33)	10,944	(23,071)
Income (loss) before income taxes	(211,222)	(11,606)	6,051	10,944	(205,833)
INCOME TAX (PROVISION) BENEFIT	(615)	—	—	—	(615)
NET INCOME (LOSS)	(211,837)	(11,606)	6,051	10,944	(206,448)
Net income attributable to noncontrolling interest	—	—	—	5,389	5,389
NET (LOSS) INCOME APPLICABLE TO GMX RESOURCES	(211,837)	(11,606)	6,051	5,555	(211,837)
Preferred stock dividends	6,720	—	—	—	6,720
NET (LOSS) INCOME APPLICABLE TO COMMON SHAREHOLDERS	$ (218,557)	$ (11,606)	$ 6,051	$ 5,555	$ (218,557)
Year Ended December 31, 2010					
TOTAL REVENUES	$ 95,108	$ 2,164	$ 8,473	$ (9,222)	$ 96,523
EXPENSES					
Lease operations	14,850	2,540	1,831	(8,570)	10,651
Production and severance taxes	743	—	—	—	743
Depreciation, depletion, and amortization	34,958	736	2,367	—	38,061
Impairment of oil and natural gas properties and assets held for sale	132,893	4,414	6,405	—	143,712
General and administrative	25,851	1,540	380	(652)	27,119
Total expenses	209,295	9,230	10,983	(9,222)	220,286
Income (loss) from operations	(114,187)	(7,066)	(2,510)	—	(123,763)
NON-OPERATING INCOME (EXPENSE)					
Interest expense	(18,640)	—	(2)	—	(18,642)
Interest and other income (expense)	60	(17)	(47)	—	(4)
Gain (loss) on derivatives	(122)	—	—	—	(122)
Equity income (loss) of subsidiaries	(12,756)			12,756	—
Total non-operating expense	(31,458)	(17)	(49)	12,756	(18,768)
Income (loss) before income taxes	(145,645)	(7,083)	(2,559)	12,756	(142,531)
INCOME TAX (PROVISION) BENEFIT	4,239	—	—	—	4,239
NET INCOME (LOSS)	(141,406)	(7,083)	(2,559)	12,756	(138,292)
Net income attributable to noncontrolling interest	—	—	—	3,114	3,114
NET (LOSS) INCOME APPLICABLE TO GMX RESOURCES	(141,406)	(7,083)	(2,559)	9,642	(141,406)
Preferred stock dividends	4,633	—	—	—	4,633
NET (LOSS) INCOME APPLICABLE TO COMMON SHAREHOLDERS	$ (146,039)	$ (7,083)	$ (2,559)	$ 9,642	$ (146,039)

	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
			(In thousands)		
Year Ended December 31, 2009					
TOTAL REVENUES	$ 93,657	$ 9,010	$ 1,022	$ (9,395)	$ 94,294
EXPENSES					
Lease operations	14,628	2,153	341	(5,346)	11,776
Production and severance taxes	(930)	—	—	—	(930)
Depreciation, depletion, and amortization	25,412	6,415	374	(1,195)	31,006
Impairment of oil and natural gas properties and assets held for sale	188,150	—	—	—	188,150
General and administrative	20,166	3,988	90	(2,854)	21,390
Total expenses	247,426	12,556	805	(9,395)	251,392
Income (loss) from operations	(153,769)	(3,546)	217	—	(157,098)
NON-OPERATING INCOME (EXPENSE)					
Interest expense	(16,747)	—	(1)	—	(16,748)
Gain (loss) on extinguishment of debt	(4,976)	—	—	—	(4,976)
Interest and other income (expense)	72	—	—	—	72
Gain (loss) on derivatives	(2,370)	—	—	—	(2,370)
Equity income (loss) of subsidiaries	(3,503)			3,503	—
Total non-operating expense	(27,524)	—	(1)	3,503	(24,022)
Income (loss) before income taxes	(181,293)	(3,546)	216	3,503	(181,120)
INCOME TAX (PROVISION) BENEFIT	33	—	—	—	33
NET INCOME (LOSS)	(181,260)	(3,546)	216	3,503	(181,087)
Net income attributable to noncontrolling interest	—	—	—	173	173
NET (LOSS) INCOME APPLICABLE TO GMX RESOURCES	(181,260)	(3,546)	216	3,330	(181,260)
Preferred stock dividends	4,625	—	—	—	4,625
NET (LOSS) INCOME APPLICABLE TO COMMON SHAREHOLDERS	$ (185,885)	$ (3,546)	$ 216	$ 3,330	$ (185,885)

Condensed Consolidating Statements of Cash Flows

	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
			(In thousands)		
Year Ended December 31, 2011					
Net cash provided by (used in) operating activities	$ 37,240	$ 3,534	$ 9,819	$ —	$ 50,593
Net cash provided by (used in) investing activities	(197,174)	(426)	8,031	—	(189,569)
Net cash provided by (used in) financing activities	256,584	—	(17,472)	—	239,112
Net increase (decrease) in cash	96,650	3,108	378	—	100,136
Cash and cash equivalents at beginning of period	1,468	564	325	—	2,357
Cash and cash equivalents at end of period	$ 98,118	$ 3,672	$ 703	$ —	$ 102,493
Year Ended December 31, 2010					
Net cash provided by (used in) operating activities	$ 54,708	$ (1,567)	$ 5,594	$ —	$ 58,735
Net cash provided by (used in) investing activities	(171,470)	(1,753)	(2,777)	—	(176,000)
Net cash provided by (used in) financing activities	86,657	—	(2,589)	—	84,068
Net increase (decrease) in cash	(30,105)	(3,320)	228	—	(33,197)
Cash and cash equivalents at beginning of period	31,573	3,884	97	—	35,554
Cash and cash equivalents at end of period	$ 1,468	$ 564	$ 325	$ —	$ 2,357
Year Ended December 31, 2009					
Net cash provided by (used in) operating activities	$ 28,242	$ 20,877	$ 371	$ —	$ 49,490
Net cash provided by (used in) investing activities	(159,930)	(20,920)	(474)	—	(181,324)
Net cash provided by (used in) financing activities	160,472	—	200	—	160,672
Net increase (decrease) in cash	28,784	(43)	97	—	28,838
Cash and cash equivalents at beginning of period	2,789	3,927	—		6,716
Cash and cash equivalents at end of period	$ 31,573	$ 3,884	$ 97	$ —	$ 35,554

NOTE O—QUARTERLY FINANCIAL DATA (UNAUDITED)

Summarized unaudited quarterly financial data for 2011 and 2010 are as follows:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands, except per share data)			
2011				
Oil and gas sales	$ 29,377	$ 32,888	$ 28,364	$ 26,112
Loss before income taxes(1)	(50,396)	(10,364)	(68,298)	(76,775)
Net loss(1)	(51,828)	(11,800)	(65,911)	(76,909)
Net loss applicable to GMX Common Shareholders(1)	(54,450)	(15,383)	(68,929)	(79,795)
Basic earnings (loss) per share(2)	(1.29)	(0.28)	(1.21)	(1.39)
Diluted earnings (loss) per share(2)	(1.29)	(0.28)	(1.21)	(1.39)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands, except per share data)			
2010				
Oil and gas sales	$ 21,300	$ 23,213	$ 24,833	$ 27,177
Income (loss) before income taxes(1)	(504)	1,167	1,570	(144,763)
Net income (loss)(1)	5,284	(1,202)	4,504	(146,878)
Net income (loss) applicable to GMX Common Shareholders(1)	3,815	(2,977)	2,168	(149,045)
Basic earnings (loss) per share(2)	0.14	(0.11)	0.08	(5.27)
Diluted earnings (loss) per share(2)	0.14	(0.11)	0.08	(5.27)

(1) 2011 losses include impairment charges on our oil and natural gas properties due to a ceiling test write-down of $48.1 million, $11.5 million, $60.9 million and $76.0 million for the first, second, third and fourth quarters of 2011, respectively. 2011 losses also include impairment charges related to assets held for sale of $0.2 million, $5.4 million, $1.7 million and $2.1 million for the first, second, third and fourth quarters of 2011, respectively. The fourth quarter 2010 loss includes a $121.9 million in impairment charge on our oil and gas properties due to a ceiling test write-down and a $10.9 million impairment charge related to assets classified as held for sale (see Note D).

(2) The sum of the per share amounts per quarter does not equal the per share amount for the year due to the changes in the average number of common shares outstanding.

NOTE P—SUBSEQUENT EVENTS

On March 7, 2012, the Company entered into an exchange agreement with four holders of its 5.00% Convertible Notes due 2013. Pursuant to this agreement, as consideration for the surrender by the holders of $4,258,000 aggregate principal amount of the 5.00% Convertible Notes, the Company will issue to the holders an aggregate of 1,655,890 shares of common stock along with cash consideration relating to accrued and unpaid interest.