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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Form 10-K

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

For the fiscal year ended December 31, 2007

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)

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(Registrant's telephone number, including area code) **(405) 600-0711**

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	The NASDAQ Stock Market, LLC Global Select
Series B Cumulative Preferred Stock, $0.001 par value	The NASDAQ Stock Market, LLC Global Select
Series A Preferred Stock Purchase Rights	The NASDAQ Stock Market, LLC Global Select

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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K 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 ☐ 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 ☒

State the aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked prices of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter. As of June 29, 2007 aggregate market value was $376,168,882.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date: As of March 10, 2008, there were 16,019,136 shares of Common Stock, par value $.001 per share, outstanding.

DOCUMENTS INCORPORATED BY REFERENCE: Portions of the Company's definitive proxy statement for our 2008 annual meeting of shareholders are incorporated into Part III of this Form 10-K by reference.

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PART I

Item 1. Business

General

GMX Resources Inc.(the "Company", "we" or "us") is a "pure play" independent oil and natural gas exploration and production company focused on development of unconventional Cotton Valley gas sands in the Sabine Uplift of the Carthage, North Field of Harrison and Panola counties of East Texas (our "core area").

We have two subsidiaries, Diamond Blue Drilling Co. ("Diamond Blue") which owns and operates three drilling rigs in our core area and Endeavor Pipeline Inc. ("Endeavor") which owns and operates our gathering system in our core area.

Our principal executive office is located at 9400 North Broadway, Suite 600, Oklahoma City, Oklahoma, 73114 and our telephone number is (405) 600-0711.

History

We were incorporated in 1998 and acquired producing and undeveloped oil and natural gas properties located primarily in our core area, Kansas and southeastern New Mexico from a bankruptcy reorganization of a small, privately-held company. We have been leasing more undeveloped acreage and drilling wells in our core area since 1998. We have since sold the Kansas properties and concentrated our efforts in our core area, primarily since 2003 when we entered into the joint development agreement with Penn Virginia Oil & Gas, L.P. ("PVOG") a wholly-owned subsidiary of Penn Virginia Corporation (NYSE: PVA).

Strategy

Our strategy is to enhance shareholder value through operational growth, acreage expansion in our core area resource play, growing and proving-up our natural gas reserves and increasing production. To date, we have experienced a 100% success rate and maintain low finding and development costs, allowing us to aggressively drill our undeveloped acreage using multiple drilling rigs. The goals of our development plan are increased production and cash flow, as well as, significant growth of our proved and unproved natural gas reserves.

Control drilling with ownership of rigs. We own and operate three rigs and use one other third party-operated rig under a well to well contract, which allows us the flexibility to pursue an aggressive drilling plan while having the ability to scale back, if necessary, in a declining commodity price environment. We have invested approximately $30 million in building our rigs.

Expand operated acreage position. We will continue to expand our operated acreage position in our core area and region, focusing on acreage we will operate and that has low risk development potential. We will review and pursue acquisitions of other properties in our core area, our region or possibly other areas that complement our goal of enhancing shareholder value.

Use leverage and hedging prudently. We will fund our drilling activities by maintaining leverage at or near levels equal to shareholders' equity and accessing equity-based funding only when market conditions warrant with the goal of limiting dilution to our existing shareholders. As of January 1, 2008, we have hedging instruments in place for approximately 45% of our current natural gas and crude oil production, and additional hedges exist for production in 2009 and 2010. We plan to continue to use hedging to mitigate commodity price risks and as required by agreements with our lenders.

Maintain production infrastructure. We have built and funded a significant amount of production infrastructure in our core area, which allows us to control marketing, processing and delivery options for the sale of our natural gas and oil. We will continue to pursue the best markets for sale of our production and will prudently expand our infrastructure to keep pace with increasing production volumes. We have invested approximately $29 million to build our pipeline gathering system and to purchase compressors.

Company Strengths

Large, continuous acreage position in the heart of the East Texas Cotton Valley natural gas play. This play is mature and well-understood with many large operators producing natural gas from positions offset to our acreage. As a result of this maturity, completion results are highly predictable, and we have had a 100% success rate.

Strong growth profile. Our inventory of 1,429 gross (931 net) proved and unproved well locations as of January 31, 2008 provides us with the ability to continue to grow production and reserves at a high rate. We have grown production and reserves at 98% and 64%, respectively, on average per year for 2006 and 2007.

Favorable economics achieved through investment in infrastructure. We have invested over $60 million in our core area for pipeline gathering systems, compression, salt water disposal and other field infrastructure and in three drilling rigs, which we use to drill vertical wells in the 100% WI Areas. Our net realized price for natural gas volumes sold was 93.4% of NYMEX for calendar year 2007. Additionally, in 2008, we have entered into natural gas processing agreements that we expect will increase our current average net sales price for a significant portion of our natural gas production. Based on natural gas liquid prices at year end 2007, we would have expected an increase in our average net natural gas sales price of $1.20 per MMBtu.

Low Finding and Development Costs. Our three-year finding and development costs have averaged $0.65 per Mcfe. We believe this is due, in part, to the focused nature of our operations and experience in developing our core area acreage. This low finding and development cost enhances our profitability and return on investment.

East Texas

As of January 31, 2008, we owned 286 gross (167 net) producing wells in our East Texas core area of which 242 gross (134 net) wells are Cotton Valley wells at depths of 8,000 to 12,000 feet and 37 gross (30 net) wells are productive in the shallower conventional Travis Peak, Hosston and Pettit formations in our core area. We have grown by developing in our core area with a 100% success rate with low finding and development costs. At December 31, 2007, we had 434.5 Bcfe of proved reserves which were 94% natural gas, 36% proved developed and 99% located in our core area. As of December 31, 2007, we have approximately 437 gross and 296 net undrilled proved undeveloped Cotton Valley location. Based on 20 acre well spacing we believe that we will have the potential to drill up to 992 gross (635 net) unproved Cotton Valley undrilled locations, depending on future prices, completion results and costs. As of January 31, 2008, we are developing our Cotton Valley core area on our 100% owned 15,395 gross (13,720 net) acres ("100% WI Area") and have worked jointly with PVOG to develop 7,740 gross (3,870 net) acres in which we generally have a 50% interest ("50% WI Area") and 11,676 gross (3,500 net) acres in which we generally have a 30% interest ("30% WI Area").

Our core area properties have 99% of our total proved reserves at December 31, 2007, 92% of our total net acreage and represented 99% of our 2007 production.

We operate 100 wells or 36% of our core area gross wells, as of January 31, 2008. Average daily production net to our interest for 2007 was 21.9 Mcf of gas and 348 Bbls of oil. The producing lives of these fields are generally 12 to 70 years. Gas sold from the area has a high MMBtu content which can result in a net price above average daily Henry Hub natural gas prices. Oil is sold separately at a slight premium to the average Sweet Crude Cushing price, inclusive of deductions. Most of the planned development will be added to existing gathering systems under comparable pricing and contracts.

The acreage in East Texas lies on the Sabine Uplift, a broad positive feature which acts as a structural trap for most reservoirs. Most of the reservoirs are shallow and deep marine sediments which tend to have tremendous aerial extent and substantial thicknesses. Natural gas and oil production has been produced from 3,000 feet to 11,700 feet in our area. The primary objective of our development is the Cotton Valley Sand, 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.

The following table sets forth the Cotton Valley wells drilled in our core area in 2007:

	Wells Drilled	
	Gross	Net
100% WI Area	39	39
50% WI Area	43	21
30% WI Area	38	11
Total	120	71

In addition to the Cotton Valley wells drilled above, we drilled 7 gross (4.6 net) shallower conventional Travis Peak, Pettit and Hosston formation wells in our core area during 2007.

Our capital expenditures in 2007, were $195 million, of which $20 million was expended on rigs, equipment and gathering systems and the balance on drilling and completion of wells, acreage acquisitions, recompletions, and costs incurred for wells to be drilled in 2008. The average Cotton Valley vertical well cost for 2007 was approximately $2 million.

In 2007, we funded our drilling and development activity in our core area with proceeds of a $65.6 million common stock offering in January 2007, proceeds from borrowings on our revolving bank credit facility, proceeds from the placement of $30 million of senior secured subordinated notes in July 2007 and cash flow from operations.

On December 4, 2007, our joint development agreement with PVOG expired in accordance with its terms. For all established drilling units in the 50% and 30% WI Areas, we will continue to participate in future drilling with PVOG under the terms of the existing joint operating agreements, which will continue in effect. In addition, our gas gathering and salt water disposal agreements with PVOG will continue in effect. To the extent there is any undeveloped acreage available for acquisition in the 50% and 30% WI Areas, either we or PVOG may acquire such acreage without any obligation to offer an interest in such acreage to the other. PVOG remains restricted from acquiring acreage in the 100% WI Area covered by the agreement for an additional year. Because operations and future drilling will continue on our jointly-owned acreage under existing joint operating agreements, we do not believe the expiration of our Joint Development Agreement with PVOG will have any material adverse effect on us. We expect to continue to participate in the drilling of new wells with PVOG in the 50% and 30% WI Areas.

The following table sets forth the proved undeveloped locations by area as of December 31, 2007, based on 40 and 20 acre spacing:

	Proved Undeveloped Locations on 40 and 20 Acre Spacing	
	Gross	Net
100% WI Area	202	202
50% WI Area	118	59
30% WI Area	117	35
Total	437	296

The pace of future development of this property will depend on the pace of PVOG's activity in the 30% and 50% WI Areas, 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. Depending on rig availability and funding, planned Cotton Valley drilling in 2008 by area is shown below.

	Expected Wells to be Drilled	
	Gross	Net
100% WI Area	41-47	41-47
50% WI Area	43	22
30% WI Area	38	11
Total	122-128	74-80

We will fund our share of this drilling from internal cash flow and borrowings under our revolving bank credit facility.

The number of wells we drill in 2008 will vary, and our potential capital expenditures may vary depending on the number of wells drilled, drilling and completion results, rig availability and other factors. We have budgeted $165 million to $185 million for capital expenditures in 2008, of which $144 million to $164 million will be for development drilling and the balance for acreage acquisitions, gathering systems and other capital expenditures.

Of the $144 million to $164 million we have budgeted for development drilling in 2008, approximately $40 million will be allocated for development of an estimated 30 new 20-acre spaced wells in our core area. The year end 2007 results from our 23 initial 20-acre spaced pilot wells drilled and completed in 2007 proved successful, with 24 hour initial average production rates of 1,447 Mcfe per day, which is 14% above the average rate for our 40-acre spaced wells.

As of January 31, 2008, there were eight rigs drilling our acreage. Four of these rigs are drilling in our 100% WI Areas, three of which are owned by our wholly-owned subsidiary, Diamond Blue with the remaining rig on a well by well contract. The other four rigs are under contract to PVOG and are drilling in our 50% and 30% WI Areas.

Other Properties

We have approximately 600 gross (369 net) acres in the Waskom Field in Clairborne, Caddo, Cataboula and Webster parishes in Louisiana with 5 gross (2.6 net) producing wells, three of which we operate. We also have properties located in Lea and Roosevelt counties, New Mexico, consisting of approximately 1,920 gross (1,458 net) acres with 9 gross (5.7 net) non-operated producing wells. Total reserves and production from these areas represent less than 1% of our proved reserves and 2007 production. We are not actively pursuing additional development of these areas.

2008 Recent Developments

Acreage Acquisition. In January 2008, we entered into a definitive agreement, subject to title due diligence, to acquire approximately 3,200 gross (3,000 net) acres of new leased undeveloped mineral rights in Harrison County, Texas, part of our core area. We expect to drill wells on the acquired acreage in 2008 using existing rig inventory. Pipeline infrastructure in the area of this acreage is sufficient for processing and selling natural gas production similar to our current field development. Successful development of this new acreage could add up to 150 new operated Cotton Valley well locations based on 20-acre well spacing. In addition, this acreage acquisition could increase the percentage of properties that we operate on a 100% ownership basis to 65%. We continue to focus on expansion of operated properties in our core area.

Natural Gas Processing Agreement. In January 2008 we reached a definitive agreement with PVR East Texas Gas Processing LLC ("PVR"), a wholly-owned subsidiary of Penn Virginia Resource Partners, L.P., to process all of the natural gas produced from wells we have jointly developed with PVOG located in the 50% and 30% WI Areas, which constituted approximately 45% of our then current production. Previously, the natural gas produced and sold from those wells was unprocessed. We believe the additional revenues from the processed natural gas liquids we will now be able to sell will increase the current average natural gas sales price for a significant portion of our PVOG natural gas production. Based on natural gas liquid prices at year end 2007, we would have expected an increase in our average net natural gas sales price of $1.20 per MMBtu. Processing of natural gas pursuant to this agreement is expected to commence no later than April 1,

2008. This agreement has a term of 10 years and we pay a gathering fee of $0.30 per MMBtu, increasing by $0.01 per year, and are entitled to 100% of the purchase price of processed natural gas liquids and residue gas. In addition, we will gain access to additional pipelines serving the Perryville, Louisiana market hub for our residue natural gas. We have negotiated a similar processing agreement to cover the balance of our production in our core area effective March 1, 2008.

Changes in Management. Ken L. Kenworthy, Sr., a co-founder of GMX, retired as our Executive Vice President, Chief Financial Officer, Secretary and Treasurer effective as of February 1, 2008. He remains as a director and will provide transition services as a consultant as requested by us. Jim Merrill, formerly our Controller, a position he has held since August 2006, became our Chief Financial Officer (and principal financial and accounting officer), Secretary and Treasurer effective February 2, 2008, to serve at the pleasure of our board of directors. Prior to joining our company, Mr. Merrill was Controller of National American Insurance Company form 1998 to 2006. National American is a privately-held multi-state property and casualty insurer based in Chandler, Oklahoma, which had net written premiums of $65 million in 2006. Prior to that time, Mr. Merrill was employed by Deloitte & Touche LLP. Mr. Merrill, age 39, is a certified public accountant and has bachelor's degrees in finance and accounting from the University of Oklahoma.

Richard Hart, Jr., P.E. was promoted to our Vice President of Operations, effective February 1, 2008. Mr. Hart, age 51, has been employed by us since March 2003 and has been directly responsible for establishing and operating our subsidiary Diamond Blue, which owns and operates three drilling rigs, and the cost control and execution of our drilling, completion and production activities. Prior to 2003, Mr. Hart was Vice President of Operations for Focus Energy. He has a Bachelor of Science in petroleum engineering from the University of Oklahoma.

Michael J. Rohleder became Vice President of Corporate Development and Investor Relations on March 5, 2008. Mr. Rohleder, age 51, brings 20 years of executive management experience to our management team with an emphasis in financing, corporate development and leadership. Prior to joining us, Mr. Rohleder served as the Sr. Vice President of Worldwide Sales and Marketing for ON Semiconductor, a $1.5b semiconductor manufacturer (formerly the Motorola Semiconductor Components Division) from 1999 to 2002. From 1991 to 1999 he was Chief Executive Officer of MEMEC North America which was a division of VEBA AG, a large German energy company. During his tenure at MEMEC, the company grew from $18 mm per year in sales to over $2.5b. Since 2002, he has served as a business consultant and managed personal investments.

Note Offering. In February 2008, we completed a private placement of $125 million of 5.00% Convertible Senior Notes due 2013. We used the net proceeds from this offering to repay all indebtedness under our revolving bank credit facility and the balance for general corporate purposes. We may reborrow under our revolving bank credit facility up to the borrowing base, currently $90 million, to fund drilling and development of our core area and for other general corporate purposes. 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.

Gas Gathering

We have acquired, constructed and own, through a wholly owned subsidiary, Endeavor, gas gathering lines and compression equipment for gathering and delivering of natural gas from our core area that we operate. As of December 31, 2007, we had invested approximately $29 million in this gathering system, including the purchase of compressors, which consisted of approximately 115 miles of gathering lines and compressors that collect and compress gas from approximately 100% of our gas production from wells in the 100% WI Area. At year end 2007, our gas gathering system had take away capacity of 62 MMcf per day compared to our year end production volumes in the 100% WI Area of 17.5 MMcf per day. In 2008, we expect to build additional miles of pipeline and purchase necessary compressors. 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. We only gather gas from wells in which we own an interest. Remaining gas is gathered by unrelated third parties. Endeavor also serves as first purchaser of gas from wells for which we are the operator. See "Item 1. Business-Marketing."

PVOG has installed and operates gathering facilities to each of the wells drilled and operated by PVOG in the 30% WI and 50% WI Areas. PVOG charges us a gathering fee of $0.10/MMBtu and actual cost of compression plus five percent (5%) for all gas gathered at the wellhead and redelivered to a central sales point. At year end 2007, the PVOG gathering system had take away capacity of 60 MMcf per day compared to production of 45 MMcf per day.

See "Item 1. Business - 2008 Plans and Recent Developments" for information relating to recently executed and planned gas processing agreements.

Diamond Blue Drilling

Our subsidiary, Diamond Blue owns three drilling rigs as described below:

Rig No.	Depth Capacity (Feet)	Drawworks Horsepower
DBD #7	11,000	1,000 HP
DBD #9	15,000	1,200 HP
DBD #11	14,000	1,000 HP

We have approximately $30 million invested in these rigs which are used to drill exclusively on our 100% owned acreage. The ownership of rigs enables us to better control drilling costs and protects us from rig availability risks when rigs are in high demand.

Reserves

As of December 31, 2007, MHA Petroleum Consultants, Inc. estimated our proved reserves to be 434.5 Bcfe. An estimated 155.0 Bcfe, is expected to be produced from existing wells and another 279.5 Bcfe or 64% of the proved reserves, is classified as proved undeveloped. All of our proved undeveloped reserves are on locations that are adjacent to wells productive in the same formations.

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 such dates.

	At December 31, 2005	2006	2007
Proved Developed:			
Gas (Bcf)	41.2	69.3	144.2
Oil (MMBbls)	.8	.9	1.8
Total (Bcfe)	45.7	74.9	155.0
Proved Undeveloped:			
Gas (Bcf)	108.8	167.6	262.1
Oil (MMBbls)	1.2	1.8	2.9
Total (Bcfe)	116.0	178.1	279.5
Total Proved:			
Gas (Bcf)	150.0	236.9	406.3
Oil (MMBbls)	2.0	2.7	4.7
Total (Bcfe)	161.7	253.0	434.5
Estimated Future Net Revenues [1]($000s)	$ 692.9	$ 519.5	$ 1,896.3
Present Value [1]($000s)	$ 245.0	$ 173.3	$ 592.8
Standardized Measure [1]($000s)	$ 185.5	$ 134.4	$ 427.7

[1] The prices used in calculating Estimated Future Net Revenues and the Present Value are determined using prices as of period end. Estimated Future Net Revenues and the Present Value give no effect to federal or state income taxes attributable to estimated future net revenues. See "Note M—Supplemental Information on Oil and Natural Gas Operations" for information about the standardized measure of discounted future net cash flows. 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. 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 which are consistent from company to company. We also understand that securities analysts use this measure in similar ways.

The increase in proved reserves, Present Value and Standardized Measure in 2007 is primarily attributable to extensions, discoveries and revisions of prior estimates resulting from our core area drilling results.

Approximately 64% of our proved reserves are undeveloped. By their nature, estimates of undeveloped reserves are less certain. In addition, the quantity and value of our proved undeveloped reserves is dependent upon our ability to fund the associated development costs which were a total of an estimated $555.7 million as of December 31, 2007, of which $154.1 million is scheduled to be expended in 2008. These estimated costs may not be accurate, development may not occur as scheduled and results may not be as estimated.

The Estimated Future Net Revenues and Present Value are highly sensitive to commodity price changes and commodity prices have recently been highly volatile. These period end prices are not necessarily the prices we expect to receive for our production but are required to be used for disclosure purposes by the SEC. We estimate that if all other factors (including the estimated quantities of economically recoverable reserves) were held constant, a $1.00 per Bbl change in oil prices and a $0.10 per Mcf change in gas prices from those used in calculating the Present Value would change such Present Value by approximately $1.4 million, and $12.7 million, respectively, as of December 31, 2007.

The estimates of proved reserves at December 31, 2007 were prepared by MHA Petroleum Consultants, Inc. and at December 31, 2006 were prepared by MHA Petroleum Consultants, Inc. in association with Sproule Associates, Inc. Sproule Associates, Inc. prepared the estimates of proved reserves as of December 31, 2005.

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.

Costs Incurred

The following table shows certain information regarding the costs incurred by us in our acquisition and development activities during the periods indicated. We have not incurred any exploration costs.

	Year Ended December 31,		
	2005	2006	2007
		(in thousands)	
Property acquisition costs - unproved	$ 1,256	$ 598	$ 1,018
Development costs	25,211	104,657	177,523
Total	$ 26,467	$ 105,255	$ 178,541

Drilling Results

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 drilling commenced. We did not acquire any wells or conduct any exploratory drilling during these periods. 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.

	Year Ended December 31,					
	2005		2006		2007	
Development wells:	Gross	Net	Gross	Net	Gross	Net
Gas	31	16	67	35.3	127	76.5
Oil	---	---	---	---	---	---
Dry	---	---	---	---	---	---
Total	31	16	67	35.3	127	76.5

Acreage

The following table shows our developed and undeveloped oil and natural gas lease and mineral acreage as of January 31, 2008. Excluded is acreage in which our interest is limited to royalty, overriding royalty and other similar interests.

	Developed		Undeveloped	
Location	**Gross**	**Net**	**Gross**	**Net**
East Texas	26,291	15,055	9,574	6,376
Other	2,520	1,827	---	---
Total	28,811	16,882	9,574	6,376

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 in the several states 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 our ownership in productive wells as of December 31, 2007. Gross oil and natural gas wells include one well with multiple completions. Wells with multiple completions are counted only once for purposes of the following table.

	Productive Wells	
Type of Well	**Gross**	**Net**
Gas	279	158.6
Oil	21	16.4
Total	300	175.0

Facilities

As of December 31, 2007, we leased 15,902 square feet in Oklahoma City, Oklahoma for our corporate headquarters. The annual rental cost is approximately $252,000. We also lease 3,000 square feet of office space in Marshall, Texas used primarily for land field operations. The annual rent is approximately $24,000.

We own a 50-acre operations field yard approximately seven miles southeast of Marshall, Texas that has 10,800 square feet of office and warehouse space. We also own 48 acres on which our gas gathering sales point is located. In addition, we own 50 acres for expansion of our field operations near Marshall, Texas.

Employees

As of December 31, 2007, we had 115 full-time employees. This compares to 99 full-time employees at December 31, 2006, reflecting the increase in our activities in 2007, including 74 employees of DBD. We also use a number of independent contractors to assist in land and field operations. We expect to add additional personnel in 2008 as our activities continue to increase. We believe our relations with our employees are satisfactory. Our employees are not covered by a collective bargaining agreement.

Marketing

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. Customers who purchase natural gas include marketing affiliates of the major 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 Inc. ("Endeavor"), which in turn sells gas to unrelated third parties. All of our gas is currently sold under contracts providing for market sensitive terms which are terminable with 30-60 day notice by either party without penalty. This means that we enjoy both the high prices in increasing price markets and suffer low prices when gas prices decline. In addition, PVOG markets 100% of the gas produced from wells operated by PVOG in the 30% WI and 50% WI Areas and we market the gas in the 100% WI Area of our joint development under the terms of month-to-month contracts on the spot market at a price with market sensitive terms. 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 the 30% WI and 50% WI Areas.

Crude Oil. Oil produced from our properties will be 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.

We do not currently have any long-term contracts to sell natural gas or crude oil. None of our gas or oil sales contracts have a term of more than one year.

In 2007, our largest purchasers of oil and natural gas were various purchases through PVOG, Crosstex Pipeline Company and TEPPCO Crude, which accounted for 45%, 45% and 7% of total oil and natural gas sales. We do not believe that the loss of any of our purchasers would have a material adverse affect 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 a much longer time than we have and have demonstrated the ability to operate through industry cycles.

Recent increased oil and natural gas drilling activity in East Texas has resulted in increased demand for drilling rigs and other oilfield equipment and services. At various times, we have and may continue to experienced 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 which 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.

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.

Environmental Matters. The discharge of oil, gas or other pollutants into the air, soil or water may give rise to liabilities to the government and third parties and may require us to incur costs to remedy discharges. 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 of oil and natural gas wells. Discharged hydrocarbons may migrate through soil to water supplies or adjoining property, giving rise to additional liabilities.

A variety of federal and state laws and regulations govern the environmental aspects of natural gas and oil production, transportation and processing and may, in addition to other laws, impose liability in the event of discharges, whether or not accidental, failure to notify the proper authorities of a discharge, and other noncompliance with those laws. Compliance with such laws and regulations may increase the cost of oil and natural gas exploration, development and production, although we do not anticipate that compliance will have a material adverse effect on our capital expenditures or earnings. Failure to comply with the requirements of the applicable laws and regulations could subject us to substantial civil and/or criminal penalties and to the temporary or permanent curtailment or cessation of all or a portion of our operations.

The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the "superfund law," imposes liability, 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 owner or operator of a disposal site or sites where the release occurred and companies that dispose or arrange for disposal of the hazardous substances found at the time. 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. We could be subject to the liability under CERCLA because our drilling and production activities generate relatively small amounts of liquid and solid waste that may be subject to classification as hazardous substances under CERCLA.

The 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 requirements, and liability for failure to meet such requirements, on a person who is either 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 counterparts to RCRA. As a result, we are not required to comply with a substantial portion of RCRA's requirements because our operations generate minimal quantities of hazardous wastes. 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, would increase the volume of hazardous waste we are required to manage and dispose of and would cause us to incur increased operating expenses.

There are numerous state laws and regulations in the states in which we operate which relate to the environmental aspects of our business. These state laws and regulations generally relate to requirements to remediate spills of deleterious substances associated with oil and natural gas activities, the conduct of salt water disposal operations, and the methods of plugging and abandonment of oil and natural gas wells which have been unproductive. Numerous state laws and regulations also relate to air and water quality.

We do not believe that our environmental risks will be materially different from those of comparable companies in the oil and natural gas industry. We believe our present activities substantially comply, in all material respects, with existing environmental laws and regulations. Nevertheless, we cannot assure you that environmental laws will not result in a curtailment of production or material increase in the cost of production, development or exploration or otherwise adversely affect our financial condition and results of operations. Although we maintain liability insurance coverage for liabilities from pollution, environmental risks generally are not fully insurable.

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.

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") that affect the economics of natural gas production, transportation and sales. 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 the 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 ultimate impact of the complex rules and regulations issued by the FERC since 1985 cannot be predicted. We cannot predict what further action the FERC will take on these matters. We do not believe that we will be affected by any action taken materially differently than other natural gas producers, gatherers and marketers with which we compete.

Additional proposals and proceedings that might affect the natural gas industry are frequently made before Congress, the FERC and the courts. The natural gas industry historically has been very heavily regulated; therefore, there is no assurance that the less stringent regulatory approach recently pursued by the FERC and Congress will continue.

Our sales of crude oil and condensate are currently not regulated and are made at market prices. In a number of instances, however, the ability to transport and sell such products are dependent on pipelines whose rates, terms and conditions of service are subject to FERC jurisdiction under the Interstate Commerce Act. However, we do not believe that these regulations affect us any differently than other crude oil producers.

Certain Technical Terms

The terms whose meanings are explained in this section are used throughout this document:

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

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.

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.

BBtu. Billion Btus.

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 in an attempt to recover proved undeveloped reserves.

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 prices 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 deprecation, 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, 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.

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.

Mcfpd. Thousand cubic feet per day.

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.

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. The estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions; i.e., prices and costs as of the date the estimate is made. Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (a) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any, and (b) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir. Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

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 are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances can estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery techniques is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

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

We file periodic reports and proxy statements with the Securities and Exchange Commission ("SEC"). The public may read and copy any materials we file with the SEC at the SEC's Public Reference Room at 100 F Street N.E., Washington, D.C. 20549. The public may obtain information about the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. We file our reports with the SEC electronically. The SEC maintains an Internet site that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC. The address of this site is http://www.sec.gov.

Our internet address is www.gmxresources.com. We make available on our website free of charge copies of our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) of the Exchange Act as soon as reasonably possible after we electronically file or furnish such material with the SEC.

Item 1A. Risk Factors.

Risks Related to GMX

The loss of our President 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 President and 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 president, we would be in default under our revolving bank credit facility, and we would also be required to offer to repurchase all of our secured notes and outstanding Series B Preferred Stock. If Mr. Kenworthy dies or becomes disabled, we would be required to offer to repurchase all of our outstanding Series B Preferred Stock, and unless we appoint a successor acceptable to our secured creditors within four months of Mr. Kenworthy's death or disability, we would also be in default under our revolving bank credit facility and required to offer to repurchase all of our secured notes.

Our wells produce oil and natural gas at a relatively slow rate.

We expect that our existing wells and 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 between 15 and 70 years. By contrast, natural gas wells located in other areas of the United States, such as offshore Gulf coast wells, may produce all of their reserves in a shorter period, for example, four to seven years. Because of the relatively slow rates of production of our wells, our reserves will be affected by long term changes in oil or 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.

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, resulting eventually in a decrease in oil and natural gas production and lower revenues and cash flows from operations. The business of exploring for, developing or acquiring reserves is capital intensive. 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. Further, our East Texas joint development partner, PVOG, may propose drilling that would require more capital than we have available from cash flow from operations or our revolving bank credit facility. In such case, we would be required to seek additional sources of financing or limit our participation in the additional drilling. In addition, our drilling activities are subject to numerous risks, including the risk that no commercially productive oil or gas reserves will be encountered.

We have not paid dividends and do not anticipate paying any dividends on our common stock in the foreseeable future.

We anticipate that we will retain all future earnings and other cash resources for the future operation and development of our business. We do not intend to declare or pay any cash dividends on our common stock in the foreseeable future. Payment of any future dividends on our common stock will be at the discretion of our board of directors after taking into account many factors, including our operating results, financial condition, current and anticipated cash needs and other factors. The declaration and payment of any future dividends on our common stock is currently prohibited by our revolving bank credit facility and secured note agreement and may be similarly restricted in the future.

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

We enter into hedging arrangements to limit our risk to decreases in commodity prices and as required under our secured note agreement. Hedging arrangements expose us to risk of financial loss in some circumstances, including the following:

- production is less than expected;
- the counter-party to the hedging contract defaults on its contact obligations; or
- 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. 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 revolving bank credit facility and secured note agreement contain certain covenants that may inhibit our ability to make certain investments, incur additional indebtedness and engage in certain other transactions, which could adversely affect our ability to meet our future goals. If our revolving bank credit facility or our secured note agreement were to be accelerated, we may not have sufficient liquidity to repay our indebtedness in full.

Our revolving bank credit facility and secured note agreement each include certain covenants that, among other things, restrict:

- our investments, loans and advances and the paying of dividends on common stock and other restricted payments;
- our incurrence of additional indebtedness;
- the granting of liens, other than liens created pursuant to the credit facility and certain permitted liens;
- mergers, consolidations and sales of all or substantial part of our business or properties; and
- the hedging, forward sale or swap of our production of crude oil or natural gas or other commodities.

Our revolving bank credit facility and secured note agreement require us to maintain certain financial ratios, such as leverage ratios. All of these restrictive covenants may restrict our ability to expend or pursue our business strategies. Our ability to comply with these and other provisions of our credit facility and secured note agreement may be impacted by changes in economic or business conditions, results of operations or events beyond our control. The breach of any of these covenants could result in a default under our credit facility and secured note agreement, in which case, depending on the actions taken by the lenders thereunder or their successors or assignees, such lenders could elect to declare all amounts borrowed under our revolving bank credit facility and secured note agreement, together with accrued interest, to be due and payable. If we were unable to repay such borrowings or interest, our lenders could proceed against their collateral. If the indebtedness under our revolving bank credit facility or secured note agreement were to be accelerated, our convertible senior notes due 2013 would also be accelerated and we may not have sufficient liquidity to repay our indebtedness in full.

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 and stock price.

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 of

December 31, 2007, we were required to comply with Section 404. Upon completion of this process, we did not identify control deficiencies under applicable SEC and Public Company Accounting Oversight Board rules and regulations that remain unremediated. 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. A "material weakness" is a significant deficiency or combination of significant deficiencies that results in more than a remote likelihood that a material misstatement of the annual or interim consolidated financial statements will not be prevented or detected. Failure to comply with Section 404 or 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. If we fail to remedy any material weakness, our consolidated financial statements may be inaccurate, we may face restricted access to the capital markets and our stock price may be adversely affected.

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 affect 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 affect on our financial condition and results of operations.

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

Approximately 99% of our estimated proved reserves at December 31, 2007 and a similar percentage of our production during 2007 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.

Servicing our debt requires a significant amount of cash, and we may not have sufficient cash flow from our business to pay our substantial debt.

Our ability to make scheduled payments of the principal of, to pay interest on or to refinance our indebtedness depends on our future performance, which is subject to economic, financial, competitive and other factors beyond our control. Our business may not continue to generate cash flow from operations in the future sufficient to service our debt and make necessary capital expenditures. If we are unable to generate such cash flow, we may be required to adopt one or more alternatives, such as selling assets, restructuring debt or obtaining additional equity capital on terms that may be onerous or highly dilutive. Our ability to refinance our indebtedness will depend on the capital markets and our financial condition at such time. We may not be able to engage in any of these activities or engage in these activities on desirable terms, which could result in a default on our debt obligations and have an adverse effect on the market price of our equity securities.

Risks Related to the Oil and Natural Gas Industry

A substantial decrease in oil and natural gas prices would have a material impact on us.

Oil and natural gas prices are volatile. A decline in prices could adversely affect our financial position, financial results, cash flows, access to capital and ability to grow. Our revenues, operating results, profitability and future rate of growth 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. The amount we can borrow under our revolving bank credit facility is subject to periodic redeterminations based on the valuation by our banks of our oil and natural gas reserves, which will depend on oil and natural gas prices used by our banks at the time of determination. In addition, we may have full-cost ceiling test write-downs in the future if prices fall significantly.

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;
- the level of consumer demand;
- the price and availability of alternative fuels;
- the availability of pipeline capacity;
- the price and level of foreign imports;
- 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;
- political instability or armed conflict in oil and natural gas producing regions, and
- the overall 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 94% of our reserves at December 31, 2007 are natural gas reserves, we are more affected by movements in natural gas prices.

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 at costs that will be as estimated or acceptable to us.

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. Also, 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 oil and natural gas prices in existence 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 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 affect on our financial condition and operating results.

At December 31, 2007, approximately 64% of our estimated proved reserves (by volume) were undeveloped. Recovery of undeveloped reserves requires significant capital expenditures and successful drilling operations. These reserve estimates include the assumption that we will make significant capital expenditures of $555.7 million to develop these reserves, including $154.1 million in 2008. However, these estimated costs may not be accurate, development may not occur as scheduled and results may not be as estimated.

We may incur write-downs of the net book values of our oil and natural gas properties that would adversely affect our shareholders' 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, less 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. A write-off constitutes a charge to earnings and reduces shareholders' equity, but does not impact our cash flows from operating activities. Future write-offs may occur which 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 can be expected to have an adverse effect on the price of our publicly traded securities.

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;
- 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;
- pollution or other environmental damage;
- clean-up responsibilities;
- regulatory investigation and penalties; and
- other losses resulting in suspension of our 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.

Governmental regulations could adversely affect our business.

Our business is subject to certain 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 of production, prevention of waste 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.

Environmental liabilities could adversely affect our business.

In the event of a release of oil, natural gas or other pollutants 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 and governmental fines. We could potentially discharge these materials into the environment in several ways, including:

- from a well or drilling equipment at a drill site;
- leakage from gathering systems, pipelines, transportation facilities and storage tanks;
- damage to oil and natural gas wells resulting from accidents during normal operations; and
- blowouts, cratering and explosions.

In addition, because we 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 that we have not yet discovered relating to the acquired properties or our other properties.

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

Competition in the oil and natural gas industry is intense, and we are smaller than many of our competitors.

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 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.

Risks Related to Our Common Stock

Shares eligible for future sale may depress our stock price.

As of March 10, 2008, we had 16,019,136 shares of common stock outstanding of which 2,395,953 shares were held by affiliates (in addition, 574,000 shares of common stock were subject to outstanding options granted under our stock option plan of which 114,500 shares were vested as of December 31, 2007). All of the shares of common stock held by our affiliates are restricted or control securities eligible for resale under Rule 144 promulgated under the Securities Act. The shares of our common stock issuable upon exercise of the stock options have been registered under the Securities Act. In addition, we have agreed to register for public offering up to 3,846,150 shares of our common stock that may be borrowed under the share lending agreement entered into in February 2008 concurrently with the pricing of the convertible senior notes due 2013. Shares that we lend under the share lending agreement may be returned to us by the share borrower and reborrowed during the term of the share lending agreement. Sales of shares of common stock under Rule 144 or another exemption under the Securities Act or pursuant to a registration statement could have a material adverse effect on the price of our common stock and could impair our ability to raise additional capital through the sale of equity securities.

The price of our common stock has been volatile and could continue to fluctuate substantially.

Our common stock is traded on The NASDAQ Global Select Market. The market price of our common stock has been volatile and could fluctuate substantially based on a variety of factors, including the following:

- fluctuations in commodity prices;
- variations in results of operations;
- legislative or regulatory changes;
- general trends in the industry;
- market conditions; and
- analysts' estimates and other events in the natural gas and crude oil industry.

Future issuance of additional shares of our common stock could cause dilution of ownership interests and adversely affect our stock price.

We may in the future issue our previously authorized and unissued securities, resulting in the dilution of the ownership interests of our shareholders. We are currently authorized to issue 50,000,000 shares of common stock on such terms as determined by our board of directors. The potential issuance of such additional shares of common stock may create downward pressure on the trading price of our common stock. We may also issue additional shares of our preferred stock or other securities that are convertible into or exercisable for common stock for capital raising or other business purposes. Future sales of substantial amounts of common stock, or the perception that sales could occur, could have a material adverse effect on the price of our common stock.

The issuance of our common stock pursuant to a share lending agreement, including sales of the shares that we will lend, and other market activity related to the share lending agreement may lower the market price of our common stock.

In connection with our offering of convertible senior notes in February 2008, we entered into a share lending agreement with an affiliate (the "share borrower") of Jefferies & Company, Inc., one of the initial purchasers of the notes. We agreed to lend up to 3,846,150 shares of our common stock to the share borrower, of which 2,140,000 shares of our common stock were sold in February 2008 in a fixed price offering and up to 1,706,150 additional shares of our common stock may be sold in an at-the-market offering following the fixed price offering, both offerings registered under the Securities Act. In February 2008, we also loaned 600,000 of the at-the-market shares. To the extent we lend any additional shares to the share borrower, the share borrower will sell those additional shares to the public in an offering registered under the Securities Act.

Jefferies & Company, Inc. informed us that it, or its affiliates, used the short position created by the sale of our common stock in the fixed price offering to facilitate transactions by which investors in the notes may hedge their investment in the notes through privately negotiated derivative transactions (the "share loan hedges"). The share loan hedges are expected to unwind during an applicable observation period immediately prior to the maturity, repurchase or conversion of our convertible senior notes and to terminate on the last trading day of such observation period.

The increase in the number of outstanding shares of our common stock issued pursuant to the share lending agreement and sales of the borrowed shares could have a negative effect on the market price of our common stock. The market price of our common stock also could be negatively affected by other short sales of our common stock by purchasers of our convertible senior notes to hedge their investment in the convertible senior notes from time to time. During any period immediately prior to the maturity, repurchase or conversion of our convertible senior notes, the share borrower, or its affiliates, and its counterparties to share loan hedges may engage in sales and purchases of our common stock in connection with the unwinding of the share loan hedges. In addition, during the term of the share loan hedges the counterparties thereto may engage in purchases or sales of shares of our common stock in connection with the hedging of their investment in our convertible senior notes. We cannot predict with certainty the effect, if any, that these future sales and purchases of our common stock will have on the market price of our common stock. However, sales of our common stock during such periods, or the perception that such sales could occur, may adversely affect prevailing market prices for our common stock.

Our existing preferred stock has greater rights than our common stock, and we may issue additional preferred stock in the future.

We have one series of preferred stock outstanding. Although we have no current plans, arrangements, understandings or agreements to issue any additional preferred stock, our certificate of incorporation authorizes our board of directors to issue one or more series of preferred stock and set the terms of the preferred stock without seeking any further approval from our shareholders. Our existing preferred stock and any future preferred stock may also rank ahead of our common stock in terms of dividends and liquidation rights. If we issue additional preferred stock, it may adversely affect the market price of our common stock. In addition, the issuance of convertible preferred stock may encourage short selling by market participants because the conversion of convertible preferred stock could depress the price of our common stock.

Our common stock is an unsecured equity interest in our company.

As an equity interest, our common stock is not secured by any of our assets. Therefore, in the event we are liquidated, the holders of our common stock will receive a distribution only after all of our secured and unsecured creditors have been paid in full. There can be no assurance that we will have sufficient assets after paying our secured and unsecured creditors to make any distribution to the holders of our common stock.

Anti-takeover provisions in our organizational documents, our convertible senior notes, other outstanding debt and Oklahoma law could have the effect of discouraging, delaying or preventing a merger or acquisition, which could adversely affect the market price of our common stock.

Several provisions of our certificate of incorporation, bylaws and Oklahoma law may discourage, delay or prevent a merger or acquisition that shareholders may consider favorable.

These provisions include:

- a shareholder rights plan;
- authorizing our board of directors to issue "blank check" preferred stock without shareholder approval;
- prohibiting cumulative voting in the election of directors;
- limiting the persons who may call special meetings of shareholders;
- establishing advance notice requirements for election to our board of directors or proposing matters that can be acted on by shareholders at shareholder meetings; and
- prohibiting shareholders from amending our bylaws.

In addition, a change in control is an event of default under our revolving bank credit facility, and a change in control also requires us to offer to purchase our senior secured notes, our Series B Preferred Stock and our convertible senior notes.

These anti-takeover provisions could substantially impede the ability of public shareholders to benefit from a change in control and, as a result, may adversely affect the market price of our common stock and your ability to realize any potential change of control premium.

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.

None.

Item 4. Submission of Matters to a Vote of Security Holders.

There were no matters submitted to a vote of security holders during the fourth quarter of 2007.

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 NASDAQ Global Market as applicable during the periods described below were as follows:

	High	Low
Year Ended December 31, 2006		
First Quarter	$ 50.50	$ 28.65
Second Quarter	47.00	25.17
Third Quarter	35.12	25.40
Fourth Quarter	48.88	30.60
Year Ended December 31, 2007		
First Quarter	$ 38.38	$ 28.35
Second Quarter	40.70	30.55
Third Quarter	36.78	30.00
Fourth Quarter	40.04	30.52

As of December 31, 2007, there were 23 record owners of our common stock and an estimated 6,500 beneficial owners.

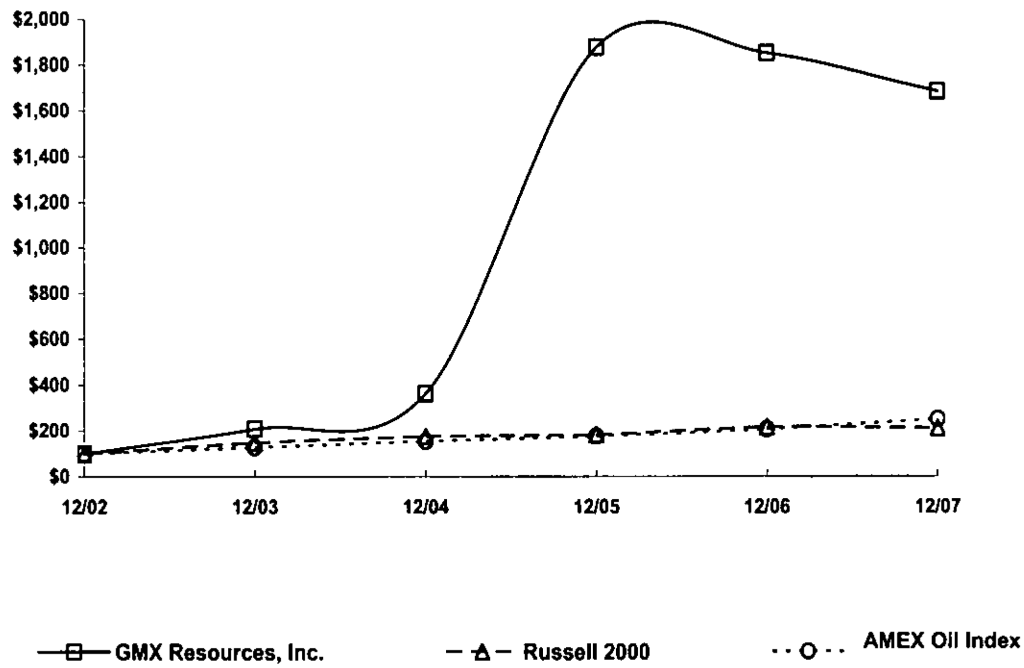
We have never declared or paid any cash dividends on our shares of common stock and do not anticipate paying any cash dividends on our shares of common stock in the foreseeable future. Currently, we intend to retain any future earnings for use in the operation and expansion of our business. Any future 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 payment of dividends is currently prohibited under the terms of our revolving bank credit facility and senior secured notes and may be similarly restricted in the future. See "Management's Discussion and Analysis of Financial Condition and Results of Operation – Revolving Bank Credit Facility and - Secured Notes."

Shareholder Return Performance Graph

The following graph compares the cumulative total shareholder returns of our Common Stock during the five years ended December 31, 2007 with the cumulative total shareholder returns of the Russell 2000 Index and the AMEX Oil Index. The comparison assumes an investment of $100 on December 31, 2003 in each of our Common Stock, the Russell 2000 Index and the AMEX Oil Index and that any dividends were reinvested.

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN*

Among GMX Resources, Inc., The Russell 2000 Index
And AMEX Oil Index



* $100 invested on 12/31/02 in stock or index-including reinvestment of dividends.
Fiscal year ending December 31.

Recent Sales of Unregistered Securities

None during 2007.

Purchases of Equity Securities

None during the fourth quarter of 2007.

Item 6. Selected Financial Data.

The following table presents a summary of our financial information for the periods indicated. 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,				
	2003	2004	2005	2006	2007
	(in thousands, except share and per share data)				
Statement of Operations Data:					
Oil and natural gas sales	$ 5,367	$ 7,690	$ 19,026	$ 31,882	$ 67,883
Interest and other income	22	144	167	151	226
Total revenues	5,389	7,834	19,193	32,033	68,109
Lease operations	850	1,261	2,070	4,479	8,982
Production and severance taxes[1]	384	519	1,241	465	2,746
General and administrative	1,579	1,986	3,389	5,829	8,717
Depreciation, depletion and amortization	1,550	2,043	3,982	8,046	18,681
Interest	439	559	143	824	4,088
Total expenses	4,802	6,368	10,825	19,643	43,214
Income before income taxes	587	1,466	8,368	12,390	24,895
Income tax expense – current	---	24	---	---	33
Income tax expense – deferred	---	---	1,212	3,415	7,977
Net income before cumulative effect of a change in accounting principle	587	1,442	7,156	8,975	16,885
Cumulative effect of a change in accounting principle	(52)	---	---	---	---
Preferred stock dividends	---	---	---	1,799	4,625
Net income applicable to common stock	$ 535	$ 1,442	$ 7,156	$ 7,176	$ 12,260
Net income per share – before cumulative effect	$ .09	$ .19	$ .81	$ .65	$ .94
Cumulative effect	(.01)	---	---	---	---
Net income per share – basic	$ .08	$ .19	$ .81	$ .65	$ .94
Net income (loss) per share - diluted	$ .08	$ .19	$ .79	$ .64	$ .93
Weighted average common shares – basic	6,560,000	7,396,880	8,797,529	11,120,204	13,075,560
Weighted average common shares – diluted	6,560,000	7,491,778	9,102,181	11,283,265	13,208,746
Statement of Cash Flows Data:					
Cash provided by (used in) operating activities	$ 1,014	$ 3,684	$ 16,323	$ 38,333	$ 52,445
Cash provided by (used in) investing activities	464	(8,878)	(39,549)	(130,573)	(194,998)
Cash provided by (used in) financing activities	(1,385)	5,419	24,756	94,807	143,500
Balance Sheet Data (at end of period):					
Oil and natural gas properties, net	$ 27,660	$ 35,957	$ 58,927	$ 157,300	$ 319,459
Total assets	31,501	40,991	81,103	210,322	395,340
Long-term debt, including current portion	6,690	3,762	1,756	41,820	125,734
Shareholders' equity	22,619	32,407	61,225	131,481	208,926

[1] Production and severance taxes in 2006 and 2007 reflect severance tax refunds of $1.4 million and $518,000, respectively, received or accrued during the year.

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

Summary Operating and Reserve Data

The following table presents an unaudited summary of certain operating and oil and natural gas reserve data for the periods indicated.

	Year Ended December 31,				
	2003	2004	2005	2006	2007
Production:					
Oil (MBbls)	35	30	48	69	127
Natural gas (MMcf)	917	1,049	1,930	3,915	7,974
Gas equivalent (MMcfe)	1,124	1,231	2,220	4,327	8,735
Average daily (MMcfe)	3.08	3.37	6.08	11.9	23.9
Average Sales Price:					
Oil (per Bbl)					
Wellhead price	$ 30.41	$ 40.83	$ 53.35	$ 63.22	$ 71.08
Effect of hedges	--	--	--	--	(1.97)
Total	$ 30.41	$ 40.83	$ 53.35	$ 63.22	$ 69.11
Natural gas (per Mcf)					
Wellhead price	$ 5.21	$ 6.15	$ 8.52	$ 6.79	$ 7.00
Effect of hedges	(0.48)	--	--	0.24	0.41
Total	$ 4.73	$ 6.15	$ 8.52	$ 7.03	$ 7.41
Average sales price (per Mcfe)	$ 4.79	$ 6.25	$ 8.57	$ 7.37	$ 7.77
Operating and Overhead Costs (per Mcfe):					
Lease operating expenses	$ .74	$ 1.03	$ .93	$ 1.04	$ 1.03
Production and severance taxes	.34	.42	.56	.11	.31
General and administrative	1.40	1.61	1.53	1.35	1.00
Total	$ 2.48	$ 3.06	$ 3.02	$ 2.50	$ 2.34
Cash Operating Margin (per Mcfe)	$ 2.31	$ 3.19	$ 5.55	$ 4.87	$ 5.43
Other (per Mcfe):					
Depreciation, depletion and amortization - oil and natural gas production	$ 1.08	$ 1.28	$ 1.58	$ 1.59	$ 1.88
Estimated Net Proved Reserves (as of period-end):					
Natural gas (Bcf)	45.0	56.9	150.0	236.9	406.3
Oil (MMbls)	1.3	1.2	2.0	2.7	4.7
Total (Bcfe)	53.0	64.3	161.7	253.0	434.5
Estimated Future Net Revenues ($MM)(1)(2)	$ 178.3	$ 211.3	$ 692.9	$ 519.5	$ 1,896.3
Present Value ($MM)(1)(2)	$ 71.2	$ 82.0	$ 245.0	$ 173.3	$ 592.8
Standardized measure of discounted future net cash flows ($MM)(3)	$ 48.0	$ 63.3	$ 185.5	$ 134.4	$ 427.7

[1] See "Item 1 Business - Certain Technical Terms."

[2] The prices used in calculating Estimated Future Net Revenues and the Present Value are determined using prices as of period end. Estimated Future Net Revenues and the Present Value give no effect to federal or state income taxes attributable to estimated future net revenues. See "Item 1 Business - Reserves."

[3] The standardized measure of discounted future net cash flows gives effect to federal and state income taxes attributable to estimated future net revenues. See "Note M -- Supplemental Information on Oil and Natural Gas Operations."

Results of Operations for the Year Ended December 31, 2007 Compared to the Year Ended December 31, 2006

Oil and Natural Gas Sales. Oil and natural gas sales in the year ended December 31, 2007 increased 113% to $67.9 million compared to the year ended December 31, 2006, due to an increase of 102% in production and a 5% increase in the average oil and natural gas price. The average price per barrel of oil and mcf of gas received in 2007 was $69.11 and $7.41, respectively, compared to $63.22 and $7.03 in the year of 2006. Oil production for 2007 increased 58 MBbls to 127 MBbls compared to 2006. Gas production increased to 7,974 MMcf compared to 3,915 MMcf for the year of 2006, an increase of 104%. Increased production in 2007 resulted from drilling and completing new wells during the year. As a result of hedging activities, additional oil and natural gas sales of $3.0 million and $940,000 were recognized for 2007 and 2006, respectively. The hedging activities increased the average Mcfe sales price by $0.35 per Mcfe and $0.22 per Mcfe for the year ended 2007 and 2006, respectively.

Lease Operations. Lease operations expense increased $4.5 million in 2007 to $9.0 million, a 101% increase compared to 2006. Increased expenses resulted from re-works of wells and additional costs to operate new wells. Lease operations expense on an equivalent unit of production basis was $1.03 per Mcfe in 2007 compared to $1.04 per Mcfe for 2006.

Production and Severance Taxes. Production and severance taxes increased 490% to $2.7 million in 2007 compared to $465,000 in 2006. Production and severance taxes are assessed on the value of the oil and natural gas produced. The increase in production and severance taxes in 2007 is due to severance tax refunds of $1.4 million that were received or accrued during 2006. During 2007, severance tax refunds of $518,000 were received or accrued during the year. Upon approval by the State of Texas, certain wells are exempt from severance taxes for a period of ten years and this will reduce our expense going forward.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense increased $10.6 million to $18.7 million in 2007, up 132% from 2006. This increase is due primarily to an increase in production for 2007. The oil and natural gas depreciation, depletion and amortization rate per equivalent unit of production was $1.88 per Mcfe in 2007 compared to $1.59 per Mcfe in 2006. Drilling and completion costs in the field were increased and were primarily the reason for increase.

Interest. Interest expense for 2007 was $4.1 million compared to $824,000 for 2006. This increase is primarily attributable to the increased amount of debt outstanding during 2007.

General And Administrative Expense. General and administrative expense for 2007 was $8.7 million compared to $5.8 million for 2006, an increase of 50%. This increase of $2.9 million was the result of increases in staff and related expenses necessary to operate at higher levels of drilling and production. Non-cash stock compensation expense increased $910,000 from $662,000 in 2006 to $1.6 million in 2007. General and administrative expense per equivalent unit of production was $1.00 per Mcfe for 2007 compared to $1.35 per Mcfe for 2006, reflecting improved efficiency levels.

Income Taxes. Income tax for 2007 was $8.0 million as compared to $3.4 million in 2006. The effective tax rates for 2006 and 2007 were 28% and 32%, respectively. The increase in the effective tax rate in 2007 is due primarily to the increase in the deferred tax liability associated with the difference between the financial carrying value of oil and natural gas properties and other property and equipment and the associated tax basis.

Net Income and Net Income Per Share. For 2007, we reported net income after preferred stock dividends of $12.3 million compared to $7.2 million for 2006. Net income per basic and fully diluted share was $0.94 and $0.93, respectively, in 2007 compared to $0.65 and $0.64 in 2006, respectively. Weighted average fully-diluted shares outstanding increased by 17% from 11,283,265 in 2006 to 13,208,746 in 2007.

Results of Operations for the Year Ended December 31, 2006 Compared to the Year Ended December 31, 2005

Oil and Natural Gas Sales. Oil and natural gas sales in the year ended December 31, 2006 increased 68% to $31.9 million compared to the year ended December 31, 2005, due to an increase of 95% in production and a 14% decrease in the average oil and natural gas price. The average price per barrel of oil and mcf of gas received in 2006 was $63.22 and $7.03, respectively, compared to $53.35 and $8.52 in the year of 2005. Oil production for 2006 increased 21 MBbls to 69 MBbls compared to 2005. Gas production increased to 3,915 MMcf compared to 1,930 MMcf for the year of 2005, an increase of 103%. Increased production in 2006 resulted from drilling and completing new wells during the year.

Lease Operations. Lease operations expense increased $2.4 million in 2006 to $4.5 million, a 116% increase compared to 2005. Increased expenses resulted from re-works of wells and additional costs to operate new wells. Lease operations expense on an equivalent unit of production basis was $1.04 per Mcfe in 2006 compared to $.93 per Mcfe for 2005, which increased due to new wells and well workovers.

Production and Severance Taxes. Production and severance taxes decreased 63% to $465,000 in 2006 compared to $1.2 million in 2005. Production and severance taxes are assessed on the value of the oil and natural gas produced. The decrease in production and severance taxes in 2006 is due to severance tax refunds of $1.4 million that were received or accrued during the year. Upon approval by the State of Texas, certain wells are exempt from severance taxes for a period of ten years and this will reduce our expense going forward.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense increased $4.1 million to $8.0 million in 2006, up 102% from 2005. This increase is due primarily to an increase in production for 2006. The oil and natural gas depreciation, depletion and amortization rate per equivalent unit of production was $1.59 per Mcfe in 2006 compared to $1.58 per Mcfe in 2005. Drilling and completion costs in the field were increased and were primarily the reason for increase.

Interest. Interest expense for 2006 was $824,000 compared to $142,000 for 2005. This increase is primarily attributable to the increased amount of debt outstanding during 2006.

General And Administrative Expense. General and administrative expense for 2006 was $5.8 million compared to $3.4 million for 2005, an increase of 72%. This increase of $2.4 million was the result of a change in accounting principle relating to stock options, increases in staff necessary to operate at higher levels of drilling and production, and costs incurred to comply with Sarbanes Oxley Section 404 requirements. General and administrative expense per equivalent unit of production was $1.35 per Mcfe for 2006 compared to $1.53 per Mcfe for 2005, reflecting slightly improved efficiency levels.

Income Taxes. Income tax for 2006 was $3.4 million as compared to $1.2 million in 2005. A deferred non-cash tax provision was booked for 2006 reflecting a 28% effective rate. We expect our deferred non-cash tax provision to continue to increase in 2007.

Net Income and Net Income Per Share. For 2006, we reported net income of $7.2 million after preferred dividends at $1.8 million compared to $7.2 million for 2005. Net income per basic and fully diluted share was $0.65 and $0.64, respectively, in 2006 compared to $0.81 and $0.79 in 2005, respectively. Weighted average fully-diluted shares outstanding increased by 24% from 9,102,181 in 2005 to 11,283,265 in 2006.

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 investment activities. Our cash flows from operating activities are substantially dependent upon oil and natural gas prices and significant decreases in market prices of oil or natural gas could result in reductions of cash flow and affect the amount of our capital investment.

Cash Flow—Year Ended December 31, 2007 Compared to Year Ended December 31, 2006. In 2007, we had a positive cash flow from operating activities of $52.4 million as a result of increased production volume during 2007. Our cash flow from operating activities in 2006 was $38.3 million. Cash flow from operating activities before increase in working capital was $45.4 million compared to $21.1 million in 2006. This resulted from a 113% increase in oil and natural gas sales in 2007. We received a net $143.5 million in cash from financing activities in 2007 compared to 2006 amounts of $94.8 million. The cash flow from financing activities in 2007 was primarily from the sale of common stock of $65.7 million, private placement of senior secured subordinated notes of $30 million and additional debt under our revolving bank credit facility. The cash inflow in 2006 from financing activities primarily resulted from the sale of preferred stock, common stock and additional debt under our revolving bank credit facility.

Cash Flow—Year Ended December 31, 2006 Compared to Year Ended December 31, 2005. In 2006 we had a positive cash flow from operating activities of $38.3 million as a result of increased production volume during 2006. Our cash flow from operating activities in 2005 was $16.3 million. Cash flow from operating activities before increase in working capital was $21.1 million compared to $12.5 million in 2005. This resulted from a 95% increase in oil and natural gas sales in 2006. We received a net $94.8 million in cash from financing activities in 2006 compared to 2005 amounts of $24.8 million. The cash flow from financing activities in 2006 was primarily from the sale of preferred stock of $47.1 million, the sale of common stock of $14.5 million, and additional debt. The cash inflow in 2005 from financing activities primarily resulted from the sale of common stock of $21.7 million and additional debt.

Revolving Bank Credit Facility

We have a loan agreement with Hibernia National Bank, now known as Capital One National Association, and Union Bank of California, N.A. ("Lender") providing for a secured revolving line of credit up to an amount established as the borrowing base from time to time based on a periodic evaluation of our oil and natural gas reserves (the "Borrowing Base"). The loan bears interest at the rate elected by us of either the prime rate as published in the Wall Street Journal (payable monthly) or the LIBO rate plus a margin ranging from 1.5% to 2.25% based on the amount of the loan outstanding in relation to the Borrowing Base for a period of one, two or three months (payable at the end of such period). Principal is payable voluntarily by us or is required to be paid (i) if the loan amount exceeds the Borrowing Base; (ii) if the Lender elects to require periodic payments as a part of a Borrowing Base re-determination; and (ii) at the maturity date of July 15, 2011. We are obligated to pay a facility fee equal to 0.25% per year of the unused portion of the Borrowing Base payable quarterly. The regular Borrowing Base has been adjusted from time to time and was $90 million at December 31, 2007. The loan is secured by a first mortgage on substantially all of our oil and natural gas properties, a pledge of our ownership of the stock of our subsidiaries, a guaranty from our subsidiaries and a security interest in all of the assets of our subsidiaries. The maximum amount we may borrow under the agreement is $125 million. The loan agreement was amended in February 2008 to permit the sale of our 5.00% Convertible Senior Notes due 2013.

In addition to customary reporting and compliance requirements, the principal covenants under the revolving bank credit facility are:

- Maintain a current ratio (as defined in the loan agreement) of not less than 1 to 1;
- Maintain a minimum net worth of $136 million as of December 31, 2007 adjusted annually to add 50% of our net income for the prior fiscal year and 100% of net proceeds of equity offerings;
- Maintain on a quarterly basis a rolling four quarter ratio of EBITDA to cash interest expense and preferred dividends of not less than 3 to 1;
- Maintain a hedging program on mutually acceptable terms whenever the loan amount outstanding exceeds 75% of the Borrowing Base;
- Pay all accounts payable within 60 days of the due date other than those being contested in good faith;
- Not incur any other debt other than up to $30 million of our secured notes described below, our 9.25% Preferred Stock and our $125 million of 5.00% Convertible Senior Notes due 2013;
- Not permit any liens other than those permitted by the loan agreement;
- Not make any investments, loans or advances other than as permitted by the loan agreement, which includes permitted investment in Diamond Blue Drilling for no more than three drilling rigs;

- Not engage in any mergers or consolidations or sales of all or substantially all of our assets;
- Not pay any dividends on common stock or make any other distributions with respect to our stock, including stock repurchases;
- Not permit Ken L. Kenworthy Jr. to cease being our chief executive officer, other than by reason of his death or disability if we name a successor acceptable to the lenders within four months;
- Not permit a person or group (other than existing management) to acquire more than 50% of the outstanding common stock or otherwise suffer a change in control; and
- Not to make any cash payments in respect of interest or on account of the conversion, purchase, acquisition or termination of our 5.00% Convertible Senior Notes due 2013 unless no event of default under the loan agreement exists or the payment would not result in such a default and the Borrowing Base has not been exceeded.

In December 2007, the agreement was amended to grant a temporary increase in the Borrowing Base of $30 million (the "Bridge Loan") from the existing $90 million to $120 million until the earlier of the completion of additional financing or June 30, 2008. The Bridge Loan bears interest at a rate that is 2.25% higher per annum than our other borrowings under the normal Borrowing Base and the unused facility fee is 0.25% higher than the 0.25% fee for the normal Borrowing Base. In connection with the amendment, the Company paid an upfront commitment and arrangement fees of 2.5% of the Bridge Loan or $750,000.

As of December 31, 2007, we had $94 million outstanding under the facility, including $4.1 million under the Bridge Loan. Upon closing of our $125 million 5.00% Convertible Senior Subordinated Notes in February 2008, we repaid all amounts outstanding under the revolving bank credit facility, including the Bridge Loan. We will reborrow under the facility up to the current Borrowing Base, $90 million, to fund planned capital expenditures and for other general corporate purposes. We expect the Borrowing Base to increase in 2008.

Secured Notes

In July 2007, we entered into a Note Purchase Agreement ("Note Agreement") with The Prudential Insurance Company of America ("Prudential") providing for the issuance and sale from time to time of up to $100 million in senior subordinated secured notes (the "Secured Notes") and sold to Prudential an initial tranche of $30 million of 7.58% Series A fixed rate notes due July 31, 2012 (the "Series A Notes") with interest payable quarterly. Proceeds from the sale of the Series A Notes was used for general corporate purposes including additional funding of drilling and development costs in the Cotton Valley Sands in East Texas. The Secured Notes are secured by a second lien on all of the assets of the Company and its subsidiaries and are guaranteed by the Company's subsidiaries, subject to the terms of an Intercreditor Agreement between our senior Lenders and the collateral agent for the Noteholders, including Prudential. We amended the Note Agreement in February 2008 in connection with the sale of our 5.00% Senior Convertible Notes due 2013. The principal covenants contained in the Note Agreement, in addition to customary covenants for similar transactions are:

- The ratio of Adjusted PV10 (as defined in the Note Agreement based on prescribed pricing and other parameters, which prescribes prices for oil production to be the lesser of the NYMEX strip price or $50.00 and for gas production of a fixed $6.50 per mcf) to Total Debt at the end of each quarter may not be less than 1.5 to 1;

- The ratio of Total Debt to EBITDA for the immediately preceding four quarters may not be greater than 4.0 to 1;

- The ratio of EBITDA to cash interest expense (which is defined to include dividends on outstanding preferred stock) for the immediately preceding four quarters may not be less than 2.5 to 1;

- Tangible net worth may not be less than $136 million as of March 31, 2007 plus 50% of net income and 100% of net cash proceeds from the sale of equity securities thereafter;

- We may not incur senior bank debt in excess of $125 million without the consent of the Noteholders;

- Neither the Company nor any subsidiaries may incur any liens other than under the Company's senior bank loan agreement and the Secured Notes, other than certain permitted liens;

- We may not issue Secured Notes in excess of the Series A Notes without the consent of Prudential and pro forma compliance with the financial covenants, which additional debt would also require the consent of our Lender under the senior revolving bank credit facility;

- We may not incur any other indebtedness without pro forma compliance with the financial covenants, and without subordination terms satisfactory to Prudential, which additional debt would also require the consent of our Lender under the senior revolving bank credit facility. In this regard, Prudential agreed that we could issue our 5.00% Senior Convertible Notes due 2013; provided no cash payments in respect of interest on such notes or on account of the conversion, purchase, acquisition, cancellation or termination of such notes may be made by us unless after giving effect thereto (a) no event of default under the Note Agreement exists, and (b) no event exists that, with the giving of notice, the passage of time or the satisfaction of other conditions precedent, would be an event of default under the Note Agreement;

- We are required to maintain commodity price hedges with a term of not greater than three years and with notional amounts (i) greater than 25% of projected production for the following 12 months from proved developed producing reserves and (ii) not more than the lesser of (a) 75% of projected production for the following 12 months from all proved reserves or (b) 90% of projected production for the following 12 months from proved developed reserves; and

- We may not issue any additional redeemable preferred stock without the consent of Noteholders, which would also require the consent of our Lender under the senior revolving bank credit facility.

In the event of a change in control, defined to be an acquisition of greater than 50% of our outstanding voting stock (other than an acquisition by a public company meeting specified financial requirements) or change in management (defined as Ken L. Kenworthy, Jr. not being the chief executive officer for any reason, except that upon Mr. Kenworthy's death or disability, we have the ability to avoid a change in management if we name a successor chief executive officer acceptable to Prudential within four months), the Company is required to give notice to the Noteholders and offer to repurchase the Subordinated Notes at the outstanding principal amount plus accrued interest plus, in the case of any fixed rate notes, including the Series A Notes, a yield maintenance amount.

2007 Common Stock Offering

Common Stock. In February 2007, we completed a public offering of 2,000,000 shares of our common stock for $34.82 per share. Net proceeds to us were approximately $65.6 million, which we used to fund drilling and development of our East Texas properties and for other general corporate purposes.

Convertible Notes

In February 2008, we completed a $125 million private placement of 5.00% Convertible Senior Subordinated Notes due 2013 (the "Notes"). Net proceeds of approximately $121 million were used to repay our revolving bank credit facility. We expect to use availability under the revolving bank credit facility to fund drilling and development costs.

The Notes are governed by an indenture, dated as of February 15, 2008 (the "Indenture") between the Company and The Bank of New York Trust Company, N.A., as trustee (the "Trustee").

The 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 Notes mature on February 1, 2013, unless earlier converted or repurchased by us.

Holders may convert their 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 (the "measurement period") in which the trading price (as defined below) per $1,000 principal amount of 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 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 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 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 declines from a high of 30% to 0% as the stock price at the time of the fundamental change increases from $25.00 and the remaining time to maturity of the Notes decreases.

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

The Notes are senior unsecured obligations of the Company and rank equally in right of payment to all of the Company's other existing and future senior indebtedness. The Notes are effectively subordinated to all our secured indebtedness, including indebtedness under our revolving bank credit facility and our senior secured notes, to the extent of the value of our assets pledged as collateral for such indebtedness. The Notes are also effectively subordinated to all liabilities of our subsidiaries, including liabilities under any guarantees they have issued.

Share Lending Agreement

In February 2008, in connection with the offer and sale of the 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 will loan to the share borrower up to the maximum number of shares of our common stock underlying our Notes during a specified loan availability period. This maximum number of shares is 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. We loaned to the share borrower 2,740,000 shares on February 15, 2008.

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 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.

In view of the contractual undertakings of the share borrower in the Share Lending Agreement, which have the effect of substantially eliminating the economic dilution that otherwise would result from the issuance of the borrowed shares, we believe that 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.

Working Capital

At December 31, 2007, we had a working capital deficit of $28.1 million. Including availability under our credit facility, our working capital deficit as of December 31, 2007 would have been $2.1 million.

Commitments and Capital Expenditures

The following table reflects the Company's contractual obligations as of December 31, 2007, as adjusted for the sale of the Notes in February 2008.

Contractual Obligations		Total		Less than 1 year		1-3 years		3-5 years		More than 5 years
	Payments Due by Period									
						(in thousands)				
Long-term debt	$	155,000	$	---	$	---	$	30,000	$	125,000
Operating leases		611		276		335		---		---
Asset retirement obligations		3,625		525		56		45		2,999
75% PVOG Financing[1]		1,735		182		324		280		949
Total	$	160,971	$	983	$	715	$	30,325	$	128,948

[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 our revolving bank credit facility, the Secured Notes, the 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, additional funding under our revolving bank credit facility or working capital.

Liquidity and Financing Considerations

We have projected capital expenditures in 2008 of $165 million to $185 million. We expect production from our wells drilled and completed in 2006 and 2007 to provide cash flow to support additional drilling in 2008 and beyond. Our 2007 cash flow from operations after preferred stock dividends was significantly greater than 2006, and we expect another increase in 2008. The indebtedness under the revolving bank credit facility of $106 million at February 14, 2008, was repaid from the proceeds of the Note offering. Therefore, we will have availability under our revolving bank credit facility with the current Borrowing Base determination of $90 million and we expect that increases in the Borrowing Base may occur during the year as additional production is established. As a result, we believe we could fund from these sources substantially all of our 2008 capital expenditures, depending on gas prices and drilling results.

2008 Guidance

We estimate first quarter 2008 production to be 2.8 Bcfe.

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 Calculations

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. 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 properties 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 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. There can be no assurance that 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 full cost property writedown. 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 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 and costs in effect as of the last day of the period are generally held constant indefinitely. Therefore, the future net revenues associated with the estimated proved reserves are not based on our assessment of future prices or costs, but rather are based on such prices and costs in effect as of the end of each quarter when the ceiling calculation is performed.

Because the ceiling calculation dictates that prices in effect as of the last day of the applicable quarter 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, on any particular day at the end of a quarter, can be either substantially higher or lower than various industry long-term price forecasts. Therefore, oil and natural gas property writedowns that result from applying the full cost ceiling limitation, 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.

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. Statement of Financial Accounting Standard ("SFAS") No. 143, "*Accounting for Asset Retirement Obligations*," requires that the discounted fair value of a liability for an ARO be recognized 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 capitalized cost, including revisions thereto, is charged to expense through DD&A.

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 the deferred tax assets will be recovered from future taxable income. If we believe that recovery is not more likely than not, 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

SFAS No. 133, "*Accounting for Derivative Instruments and Hedging Activities*" ("SFAS 133"), as amended, requires that all derivative instruments subject to the requirements of the statement be measured at fair value and recognized as assets or liabilities in the balance sheet. 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.

Ineffective portions of a cash flow hedging derivative's change in fair value are recognized currently in earnings as other 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.

We do not hold or issue derivative instruments for trading purposes. Our commodity price financial swaps and collars were designated as cash flow hedges. Changes in fair value of these derivatives were reported in accumulated other comprehensive income net of deferred income tax. These amounts were reclassified to oil and natural gas sales when the forecasted transaction took place. Our cash flow hedge were determined to be highly effective at December 31, 2007. See Note C – Derivative Activities to our consolidated financial statements.

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 collectibility 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, 2006 or 2007.

Other

See Note A to Consolidated Financial Statements for information related to other accounting and reporting policies.

Recently Issued Accounting Pronouncements

See Note A to Consolidated Financial Statements for a discussion of recently issued accounting pronouncements.

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.

Price Risk Management

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

Forward-Looking Statements

All statements made in this document other than purely historical information are "forward looking statements" within the meaning of the federal securities laws. These statements reflect expectations and are based on historical operating trends, proved reserve positions and other currently available information. Forward looking statements include statements regarding future plans and objectives, future exploration and development expenditures and number and location of planned wells and statements regarding the quality of our properties and potential reserve and production levels. These statements may be preceded or followed by or otherwise include the words "believes," "expects," "anticipates," "intends," "continues," "plans," "estimates," "projects" or similar expressions or statements that events "will," "should," "could," "might" or "may" occur. Except as otherwise specifically indicated, these statements assume that no significant changes will occur in the operating environment for oil and natural gas properties and that there will be no material acquisitions or divestitures except as otherwise described.

The forward-looking statements in this report are subject to all the risks and uncertainties which are described in this document. We may also make material acquisitions or divestitures or enter into financing transactions. None of these events can be predicted with certainty and are not taken into consideration in the forward-looking statements.

For all of these reasons, actual results may vary materially from the forward looking statements and we cannot assure you that the assumptions used are necessarily the most likely. We will not necessarily update any forward looking statements to reflect events or circumstances occurring after the date the statement is made except as may be required by federal securities laws.

There are a number of risks that may affect our future operating results and financial condition. See "Item 1A. Risk Factors."

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

Commodity Price Risk

We are subject to price fluctuations for natural gas and crude oil. Prices received for natural gas sold on the spot market are volatile due primarily to seasonality of demand and other 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 and quantities of reserves recoverable on an economic basis. Any reduction in reserves, including reductions due to price fluctuations, can reduce our borrowing base under our revolving bank credit facility and 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 oil and natural gas production through financial price swaps and collars. Our revolving bank credit facility requires us to maintain a hedging program on mutually acceptable terms whenever the loan amount outstanding exceeds 75% of the Borrowing Base, which occurred in 2007. In addition, the note agreement for our Series A Notes requires us to maintain a certain levels of hedge. For swap instruments, we received a fixed price for our production and pay a variable market 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. Collars contain a fixed floor price (put) and ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, we receive the fixed price and pay the market price. If the market price is between the call and the put strike price, no payments are due from either party. The gains and losses realized as a result of these activities are substantially offset in the cash market when the commodity is delivered. Following is a summary of the outstanding oil and natural gas swaps and collars we have in place as of January 31, 2008:

Effective Date	Maturity Date	Notional Amount Per Month	Remaining Notional Amount as of December 31, 2007	Fixed Price per	Put Fixed Price	Call Fixed Price
Natural Gas (MMBtu):						
2/1/2007	12/31/2008	200,000	2,400,000	$7.46	---	---
8/1/2007	12/31/2008	100,000	1,200,000	$7.60	---	---
1/1/2008	12/31/2009	100,000	2,400,000	---	$7.50	$8.15
1/1/2009	12/31/2009	200,000	2,400,000	---	$7.50	$9.17
1/1/2010	12/31/2010	300,000	3,600,000	---	$7.50	$8.91
Oil (Bbls):						
9/1/2007	12/31/2008	5,000	65,000	$70.00	---	---

All natural gas contracts are based on Houston Ship Channel Index Prices and all oil contracts are based on West Texas Intermediate which historically have had a high degree of correlation with the actual prices received by the Company.

The fair value of our natural gas and oil swaps and collar in effect at December 31, 2007 was a liability of $2.0 million, assuming that gas prices in effect at December 31, 2007 remain in effect for the life of the swaps and collar. Based on the monthly notional amount for natural gas in effect at December 31, 2007, a hypothetical $1.00 increase in natural gas prices would have decreased the cash flow and earnings from our natural gas swaps and collar by $300,000 per month and a $1.00 decrease in natural gas prices would increase the cash flow and earnings from our natural gas swaps and collar by $300,000 per month. Based on the monthly notional amount for oil in effect at December 31, 2007, a hypothetical $1.00 increase in oil prices would have decreased the cash flow and earnings for our oil swap by $5,000 per month and a $1.00 decrease in oil prices would increase the cash flow and earnings by $5,000 per month.

Interest Rate Risk

As of December 31, 2007, we had $94.0 million of long-term debt outstanding under our revolving bank credit facility. The credit facility matures in July 2011 and is governed by a borrowing base calculation that is redetermined periodically. We have the option to elect interest at (1) LIBOR plus 1.50% to 2.25% depending on the level of borrowings relative to the borrowing base or (2) prime rate. As a result, our interest costs fluctuate based on short-term interest rates relating to our credit facility. Based on borrowings outstanding at December 31, 2007, a 100 basis point change in interest rates would change our interest expense by approximately $940,000. We had no interest rate derivatives during 2007.

Our $30 million of Secured Notes and $125 million of Notes have fixed interest rates of 7.58% and 5.00%, respectively.

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 evaluated our disclosure controls and procedures (as defined in rules adopted by the Securities and Exchange Commission) as of December 31, 2007, and have concluded that these controls and procedures are effective to ensure that information required to be disclosed by us in the reports that we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized, and reported within the time periods specified in the SEC's rules and forms. These disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by us in the reports that we file or submit is accumulated and communicated to management, including the principal executive officer and the principal financial officer, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control Over Financial Reporting

During the fourth quarter of 2007, 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. Under the supervision and with the participation of our management, including our chief executive officer and chief financial officer, we evaluated the effectiveness of the design and operation of our internal control over financial reporting based on the framework in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on that evaluation, our chief executive officer and chief financial officer concluded that our internal control over financial reporting was effective as of December 31, 2007, as reflected in our report included in Item 8.

Smith, Carney & Co., p.c., our independent registered public accounting firm, audited internal control over financial reporting and, based on that audit, issued the report set forth in Item 8.

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), information required by Items 10 through 14 of Form 10-K are incorporated herein by reference to the Company's Proxy Statement for the Annual Meeting of Shareholders to be filed prior to April 29, 2008.

PART IV

Item 15. Exhibits and Financial Statement Schedules.

The following documents are filed as part of this report.

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

2. 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 13, 2008

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.	President and Director (Principal Executive Officer)	March 13, 2008
/s/ James A. Merrill James A. Merrill	Chief Financial Officer (Principal Financial and Accounting Officer)	March 13, 2008
/s/ T.J. Boismier T. J. Boismier	Director	March 13, 2008
/s/ Steven Craig Steven Craig	Director	March 13, 2008
/s/ Ken L. Kenworthy, Sr. Ken L. Kenworthy, Sr.	Director	March 13, 2008
/s/ Jon W. McHugh Jon W. McHugh	Director	March 13, 2008

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and
Stockholders of GMX Resources Inc. and Subsidiaries

We have audited the accompanying balance sheets of GMX Resources Inc. and Subsidiaries as of December 31, 2007 and 2006, and the related statements of income, stockholders' equity and comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2007. We also have audited GMX Resources Inc. and Subsidiaries Internal Control Over Financial Reporting as of December 31, 2007, based on criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). GMX Resources Inc.'s management is responsible for these financial statements, 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 these financial statements and an opinion on the Company's internal control over financial reporting 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 audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audit of financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material misstatement exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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, the financial statements referred to above present fairly, in all material respects, the financial position of GMX Resources Inc. and Subsidiaries as of December 31, 2007 and 2006, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2007 in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, GMX Resources Inc. and Subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

Smith, Carney & Co., p.c.

Oklahoma City, Oklahoma
March 10, 2008

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 Rules 13(a) – 15(f) and 15d – 15(f) of the Securities Exchange Act of 1934, as amended. In order to evaluate the effectiveness of internal control over financial reporting, as required by Section 404 of the Sarbanes-Oxley Act, our management has 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"). 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.

Based on the assessment, our management has concluded that we maintained effective internal control over financial reporting as of December 31, 2007, based on criteria in *Internal Control–Integrated Framework* issued by COSO. Our internal control over financial reporting as of December 31, 2007, has been audited by Smith, Carney & Co., p.c., an independent registered public accounting firm, as stated in their report which is included herein.

Our management, including our chief executive officer and chief financial officer, does not expect that our disclosure controls and procedures or our internal controls will prevent all errors and all fraud. 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. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the company have been detected.

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

	December 31, 2006	December 31, 2007
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 4,960	$ 5,907
Accounts receivable—interest owners	64	906
Accounts receivable—oil and natural gas revenues	5,766	10,258
Derivative instruments	1,176	---
Inventories	373	1,558
Prepaid expenses and deposits	1,285	1,720
Total current assets	13,624	20,349
OIL AND NATURAL GAS PROPERTIES, BASED ON THE FULL COST METHOD		
Properties being amortized	173,050	350,573
Properties not subject to amortization	1,125	2,143
Less accumulated depreciation, depletion, and amortization	(16,875)	(33,257)
	157,300	319,459
PROPERTY AND EQUIPMENT, AT COST, NET	39,355	54,957
OTHER ASSETS	43	575
TOTAL ASSETS	$ 210,322	$ 395,340
LIABILITIES AND SHAREHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 24,658	$ 34,941
Accrued expenses	3,551	3,778
Revenue distributions payable	513	3,667
Derivative instruments	---	1,720
Current maturities of long-term debt	251	4,321
Total current liabilities	28,973	48,427
LONG-TERM DEBT, LESS CURRENT MATURITIES	41,569	121,413
OTHER LIABILITIES	3,272	4,649
DEFERRED INCOME TAXES	5,027	11,925
SHAREHOLDERS' 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, 3,000,000 Shares authorized, 2,000,000 shares issued and outstanding (aggregate liquidation preference $50,000,000)	2	2
Common stock, par value $.001 per share–authorized 50,000,000 shares issued and outstanding 11,242,136 shares in 2006 and 13,267,886 shares in 2007	11	13
Additional paid-in capital	113,266	180,543
Retained earnings	17,426	29,686
Accumulated other comprehensive income, net of taxes	776	(1,318)
Total shareholders' equity	131,481	208,926
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 210,322	$ 395,340

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,		
	2005	2006	2007
REVENUE:			
Oil and natural gas sales	$ 19,026	$ 31,882	$ 67,883
Interest income	162	150	224
Other income	5	1	2
Total revenue	19,193	32,033	68,109
EXPENSES:			
Lease operations	2,070	4,479	8,982
Production and severance taxes	1,241	465	2,746
Depreciation, depletion and amortization	3,982	8,046	18,681
Interest	143	824	4,088
General and administrative	3,389	5,829	8,717
Total expenses	10,825	19,643	43,214
Income before income taxes	8,368	12,390	24,895
INCOME TAXES	1,212	3,415	8,010
NET INCOME	7,156	8,975	16,885
Preferred stock dividends	---	1,799	4,625
NET INCOME APPLICABLE TO COMMON STOCK	$ 7,156	$ 7,176	$ 12,260
Earnings per share – Basic	$ 0.81	$ 0.65	$ .94
Earnings per share –Diluted	$ 0.79	$ 0.64	$ .93
Weighted average common shares–Basic	8,797,529	11,120,204	13,075,560
Weighted average common shares–Diluted	9,102,181	11,283,265	13,208,746

See accompanying notes to consolidated financial statements.

GMX Resources Inc. and Subsidiaries
Consolidated Statement of Shareholders' Equity and Comprehensive Income
Year Ended December 31, 2005, 2006, and 2007
(dollars and shares in thousands)

	Preferred shares	Common shares	Preferred par value	Common par value	Additional paid-in capital	Retained earnings	Accumulated other comprehensive income	Total shareholders' equity
BALANCE AT DECEMBER 31, 2004	---	8,054	$ ---	$ 8	$ 29,305	$ 3,094	$ ---	$ 32,407
Options Exercised	---	128	---	---	423	---	---	423
Redeemed & Cancelled Warrants	---	(144)	---	---	(774)	---	---	(774)
Warrants Exercised	---	337	---	---	1,667	---	---	1,667
Shares Issued	---	1,600	---	2	20,344	---	---	20,346
Net Income	---	---	---	---	---	7,156	---	7,156
BALANCE AT DECEMBER 31, 2005	---	9,975	$ ---	$ 10	$ 50,965	$ 10,250	$ ---	$ 61,225
Stock Options Exercised	---	103	---	---	556	---	---	556
Warrants Exercised	---	1,164	---	1	13,972	---	---	13,973
Stock Option Compensation Expense	---	---	---	---	662	---	---	662
Series B Preferred Shares Issued	2,000	---	2	---	47,111	---	---	47,113
Preferred Stock Dividends	---	---	---	---	---	(1,799)	---	(1,799)
Net Income	---	---	---	---	---	8,975	---	8,975
Other comprehensive income, net								
Unrealized loss and hedges, net of taxes of $718	---	---	---	---	---	---	1,396	1,396
Reclassification adjustment for hedge gains included in net income, net of taxes of $319	---	---	---	---	---	---	(620)	(620)
Total comprehensive income								9,751
BALANCE AT DECEMBER 31, 2006	2,000	11,242	$ 2	$ 11	$ 113,266	$ 17,426	$ 776	$ 131,481
Stock Options Exercised	---	26	---	---	77	---	---	77
Stock Option Compensation Expense					1,573			1,573
Preferred Stock Dividends	---	---	---	---	---	(4,625)	---	(4,625)
Shares Issued	---	2,000	---	2	65,627	---	---	65,629
Net Income	---	---	---	---	---	16,885	---	16,885
Other comprehensive income, net								
Unrealized gain and hedges, net of taxes of $53	---	---	---	---	---	---	(98)	(98)
Reclassification adjustment for hedge gains included in net income, net of taxes of $1,027	---	---	---	---	---	---	(1,996)	(1,996)
Total comprehensive income								14,791
BALANCE AT DECEMBER 31, 2007	2,000	13,268	$ 2	$ 13	$ 180,543	$ 29,686	$ (1,318)	$ 208,926

See accompanying notes to consolidated financial statements.

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

	Year Ended December 31, 2005	2006	2007
CASH FLOWS DUE TO OPERATING ACTIVITIES			
Net income	$ 7,156	$ 8,975	$ 16,885
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion, and amortization	3,982	8,046	18,681
Deferred income taxes	1,212	3,415	7,977
Non-cash stock compensation expense	---	662	1,573
Other	112	30	273
Decrease (increase) in:			
Accounts receivable	(2,666)	(1,567)	(5,333)
Inventory, prepaid expenses and other assets	(14)	(1,462)	(913)
Increase (decrease) in:			
Accounts payable	5,488	16,849	10,283
Accrued expenses and other liabilities	310	3,106	(298)
Revenue distributions payable	743	279	3,317
Net cash provided by operating activities	16,323	38,333	52,445
CASH FLOWS DUE TO INVESTING ACTIVITIES			
Purchase of oil and natural gas properties	(26,020)	(104,412)	(174,509)
Purchase of property and equipment	(13,529)	(26,161)	(20,489)
Net cash used in investing activities	(39,549)	(130,573)	(194,998)
CASH FLOWS DUE TO FINANCING ACTIVITIES			
Advance on borrowings	10,702	78,862	120,139
Payments on debt	(7,608)	(43,898)	(66,225)
Proceeds from sale of common stock	21,662	14,529	65,706
Proceeds from sale of Series B preferred stock	---	47,113	--
Dividends paid on Series B preferred stock	---	(1,799)	(4,625)
Proceeds from issuance of senior secured notes	---	---	30,000
Fees paid related to financing activities	---	---	(1,495)
Net cash provided by financing activities	24,756	94,807	143,500
NET INCREASE IN CASH	1,530	2,567	947
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	863	2,393	4,960
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 2,393	$ 4,960	$ 5,907
SUPPLEMENTAL CASH FLOW DISCLOSURE			
CASH PAID DURING THE PERIOD FOR:			
INTEREST	$ 117	$ 683	$ 3,402
INCOME TAXES	$ ---	$ ---	$ --

See accompanying notes to consolidated financial statements.

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

GMX Resources Inc. and subsidiaries, (collectively, "we", "ours", "us", or the "Company") is primarily engaged in the acquisition, exploration, and development of properties for the production of crude oil and natural gas in Texas, Louisiana and New Mexico.

A summary of the significant accounting policies applied in the preparation of the accompanying financial statements follows.

PRINCIPLES OF CONSOLIDATION: The consolidated financial statements include the accounts of GMX Resources Inc. and its wholly owned subsidiaries, Endeavor Pipeline, Inc. and Diamond Blue Drilling Co. Endeavor Pipeline, Inc. owns and operates natural gas gathering facilities in East Texas. Diamond Blue Drilling Co. owns drilling rigs and drills oil and natural gas wells exclusively for GMX. All significant intercompany accounts and transactions have been eliminated.

USE OF ESTIMATES: The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America ("GAAP") requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the 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 these estimates. Significant estimates include estimates for proved oil and natural gas reserves, 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 others, and are subject to change.

RECLASSIFICATION: Certain reclassifications have been made to prior year amounts to conform to current year presentations.

CASH AND CASH EQUIVALENTS: GMX considers all highly liquid investments with maturities of three months or less at the time of purchase to be cash equivalents. The Company maintains its cash and cash equivalents in bank deposit accounts and money market accounts which, at times, may exceed federal insured limits. The Company has not experienced any losses in such accounts and believes it is not exposed to any significant risk on such accounts.

INVENTORIES: Inventories consist of lease and well equipment and crude oil on hand. The Company uses lease and well equipment in its ongoing operations and it is carried at the lower of cost or market using the specific identification method. Treated and stored crude oil inventory on hand at the end of the year is valued at the lower of production cost or market.

ACCOUNTS RECEIVABLE: The Company has receivables from joint interest owners and oil and gas purchasers which are generally uncollateralized. The Company generally 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.

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. 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, together with 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 $3.5 million, $6.9 million and $16.4 million for the years ended December 31, 2005, 2006, and 2007, respectively.

Capitalized costs are subject to a "ceiling test," which basically limits such costs to the aggregate of the "estimated present value," discounted at a 10-percent interest rate of future net revenues from proved reserves, based on current economic and operating conditions, plus the lower of cost or fair value of unproved properties. Under the ceiling test, capitalized costs, less accumulated amortization and related deferred income taxes, may not exceed an amount equal to the sum of the present value of estimated future net revenues less estimated future expenditures to be incurred in developing and producing the proved reserves less any related income tax effects.

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 using the straight-line method based on estimated useful lives ranging from five to 20 years. Depreciation and amortization expense for property and equipment was $485,000, $1.2 million and $2.3 million for the years ending December 31, 2005, 2006, and 2007, 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 in accordance with Statement of Financial Accounting Standard ("SFAS") No. 144, "*Accounting for the Impairment or Disposal of Long Lived Assets.*" This statement requires (a) recognition of an impairment loss only if the carrying amount of a long-lived asset is not recoverable from its undiscounted cash flows and (b) measurement of an impairment loss as the difference between the carrying amount and fair value of the asset.

LOAN FEES: Included in other assets are costs associated with long-term debt. These costs are being amortized over the life of the loan using a method that approximates the interest method.

REVENUE DISTRIBUTIONS PAYABLE: For certain oil and natural gas properties, GMX 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. GMX accrues revenue for only its 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.

REVENUE RECOGNITION: 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 collectibility 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 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, 2006 or 2007.

HEDGING AND RISK MANAGEMENT ACTIVITIES: The Company may enter into oil and natural gas price swaps and collars to manage its exposure to oil and natural gas price volatility. The Company accounts for these transactions in accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities,* as amended. SFAS No. 133 requires that the Company recognize all derivatives as either assets or liabilities measured at fair value. The accounting for changes in the fair value of the derivative depends on the use of the derivative and the resulting designation. Derivatives that are not hedges must be adjusted to fair value through income. 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.

The instruments are usually placed with counterparties that the Company believes are minimal credit risks. The oil and natural gas reference prices upon which the risk management instruments are based reflect various market indices that have a high degree of historical correlation with actual prices received by the Company.

Ineffective portions of a cash flow hedging derivative's change in fair value are recognized currently in earnings as other 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.

The Company does not hold or issue derivative instruments for trading purposes. The Company's commodity price financial swaps and collars were designated as cash flow hedges. Changes in fair value of these derivatives were reported in other comprehensive income net of deferred income tax. These amounts were reclassified to oil and natural gas sales when the forecasted transaction took place. The Company's cash flow hedges were determined to be highly effective at December 31, 2007.

ASSET RETIREMENT OBLIGATIONS: The Company accounts for asset retirement obligations in accordance with SFAS No. 143, *Accounting for Asset Retirement Obligations*, which requires entities to record 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. The accretion of the asset retirement obligation is included in the Company's full cost pool. 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 which may change based upon future inflation rates and changes in statutory remediation rules.

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, 2006 and 2007, the Company has not accrued for or been fined or cited for any environmental violations which 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 earnings per share ("EPS") of common stock have been computed on the basis of the weighted average number of shares outstanding during each period. The diluted EPS of common stock includes the effect of outstanding stock options which are dilutive.

The table below reflects the amount of options not included in the diluted EPS calculation above, as they were antidilutive.

	2005	2006	2007
Options excluded from dilution calculation	77,000	25,000	343,000
Range of exercise prices	\$20.01 - \$29.00	\$39.65	\$36.83 - \$39.65
Weighted average exercise price	\$20.98	\$39.65	\$38.54

STOCK BASED COMPENSATION: Effective January 1, 2006, GMX adopted SFAS No. 123(R), *Share-Based Payment*, ("SFAS No. 123(R)"), using the modified prospective transition method. SFAS No. 123(R) requires equity-classified share-based payments to employees, including grants of employee stock options, to be valued at fair value on the date of grant and to be expensed over the applicable vesting period. Under the modified prospective transition method, share-based awards granted or modified on or after January 1, 2006, are recognized in compensation expense over the applicable vesting period. Also, any previously granted awards that are not fully vested as of January 1, 2006 are recognized as compensation expense over the remaining vesting period. No retroactive or cumulative effect adjustments were required upon GMX's adoption of SFAS No. 123(R).

Prior to adopting SFAS No. 123(R), GMX accounted for its fixed-plan employee stock options using the intrinsic-value based method prescribed by Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees*, ("APB No. 25") and related interpretations. This method required compensation expense to be recorded on the date of grant only if the current market price of the underlying stock exceeded the exercise price.

GMX recognized $662,000 and $1.6 million of stock compensation expense for the years ending December 31, 2006 and 2007, respectively. These non-cash expenses are reflected as a component of the Company's general and administrative expense. The Company recorded an income tax benefit of approximately $166,000 and $191,000 related to the share based compensation expense recognized during 2006 and 2007, respectively.

Had GMX elected the fair value provisions of SFAS No. 123(R) in 2005, GMX's net income and net income per share would have differed from the amounts actually reported as shown in the following table:

	Year Ended December 31, 2005
	(in thousands, except per share amounts)
Net income as reported	$ 7,156
Add: Stock-based compensation recognized	163
Deduct: Stock-based compensation, net of tax	(467)
Pro forma net earnings	$ 6,852
Pro forma earnings per share – basic:	$ 0.78
Pro forma earnings per share – diluted	$ 0.75

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, 2005, 2006 and 2007, the Company recorded non-cash additions to oil and gas properties of $11,000, $890,000, and $2.6 million, respectively.

During the years ended December 31, 2005, 2006 and 2007, the company recorded a net non-cash asset and related liability of $922,000, ($50,000), and $1.5 million, respectively, associated with the asset retirement obligation on the acquisition and/or development of oil and gas properties.

Interest of $31,000, $111,000, and $122,000 was capitalized during the years ended December 31, 2005, 2006, and 2007, respectively, related to the unproved properties that were not being currently depreciated, depleted or amortized and on which development activities were not in progress. In addition, the Company capitalized interest of $84,000 during 2006 related to the construction of two drilling rigs.

RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS: The Financial Accounting Standards Board (FASB) recently issued the following standards which were reviewed by the Company to determine the potential impact on its financial statements upon adoption. The Company has concluded that the following new accounting standards are applicable to the Company.

In September 2006, the FASB issued SFAS No. 157, "*Fair Value Measurements*" ("SFAS 157"). SFAS 157 establishes a framework for fair value measurements in the financial statements by providing a single definition of fair value, provides guidance on the methods used to estimate fair value and increases disclosures about estimates of fair value. SFAS 157 is effective for fiscal years beginning after November 15, 2007. We do not expect that SFAS 157 will have a material impact on our consolidated financial position, results from operations or cash flows.

In February 2007, the FASB issued SFAS No. 159, "*The Fair Value Option for Financial Assets and Financial Liabilities*" ("SFAS 159"). SFAS 159 permits entities to choose to measure many financial instruments and certain other items at fair value that are not currently required to be measured at fair value. In addition, it also establishes presentation and disclosure requirements designed to facilitate comparisons between entities that choose different measurement attributes for similar types of assets and liabilities. SFAS 159 does not affect any existing accounting literature that requires certain assets and liabilities to be carried at fair value. SFAS 159 is effective as of the beginning of an entity's first fiscal year that begins after November 15, 2007. Early adoption is permitted as of the beginning of a fiscal year that begins on or before November 15, 2007, provided the entity also elects to apply the provisions of SFAS 157. We do not expect that SFAS 159 will have a material impact on our consolidated financial position, results from operations or cash flows.

In December 2007, the FASB issued SFAS No. 141 (revised 2007), *Business Combinations* ("SFAS No. 141(R)"). SFAS No. 141(R) provides companies with principles and requirements on how an acquirer recognizes and measures in its financial statements the identifiable assets acquired, liabilities assumed, and any noncontrolling interest in the acquiree as well as the recognition and measurement of goodwill acquired or a gain from a bargain purchase in a business combination. SFAS No. 141(R) also requires certain disclosures to enable users of the financial statements to evaluate the nature and financial effects of the business combination. Acquisition costs associated with the business combination will generally be expensed as incurred. In addition, changes in an acquired entity's valuation allowance for deferred tax assets and uncertain tax positions after the measurement period will impact income tax expense. SFAS No. 141(R) is effective for business combinations occurring in fiscal years beginning after December 15, 2008. Early adoption of SFAS No. 141(R) is not permitted. We have not yet assessed the impact SFAS No. 141(R) will have if we engage in future business combinations.

December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements, an amendment of ARB No. 51*, which mandates that a noncontrolling (minority) interest shall be reported in the consolidated statement of financial position within equity, separately from the parent company's equity. This statement amends ARB No. 51 and clarifies that a noncontrolling interest in a subsidiary is an ownership interest in the consolidated entity. SFAS No. 160 also requires consolidated net income to include amounts to both parent and noncontrolling interest and requires disclosure, on the face of the consolidated statement of income, of the amounts of consolidated net income attributable to the parent and to the noncontrolling interest. SFAS No. 160 is effective for fiscal years and interim periods beginning after December 15, 2008. We have not yet assessed the impact on our consolidated financial statements of adopting SFAS No. 160 effective January 1, 2009, but we do not expect it to be material as we currently do not have any minority interests that would be subject to SFAS No. 160.

In November 2007, the FASB issued its preliminary views on financial instruments with characteristics of equity as a step preceding the development of a proposed Statement of Financial Accounting Standards. Such a standard would affect accounting for convertible debt instruments that may be settled in cash upon conversion, including partial cash settlements. This accounting could increase the amount of interest expense required to be recognized with respect to such instruments and thus, lower reported net income and net income per share of issuers of such instruments. Issuers would have to account for the liability and equity components of the instrument separately and in a manner that reflects interest expense at the interest rate of similar nonconvertible debt. Our outstanding 5% senior Convertible Notes issued in February 2008 would be affected by such a standard. If the FASB adopts the statement, it is expected to be effective for fiscal years starting after December 15, 2007. Companies would have to apply the statement retrospectively to both existing and new instruments that fall within the scope of the guidance.

NOTE B--PROPERTY AND EQUIPMENT

Major classes of property and equipment included the following:

	December 31,	
	2006	2007
	(in thousands)	
Pipeline and related facilities	$ 16,049	$ 28,816
Drilling rigs	23,950	29,924
Machinery and equipment	1,198	2,047
Buildings and leasehold improvement	1,254	1,606
Office equipment	646	958
	43,097	63,351
Less accumulated depreciation and amortization	(3,742)	(8,570)
	39,355	54,781
Land	-	176
	$ 39,355	$ 54,957

NOTE C—DERIVATIVE ACTIVITIES

The Company's results of operations, financial condition and capital resources are highly dependent upon the prevailing market prices of and demand for oil and natural gas. These commodity prices are subject to wide fluctuations and market uncertainties. To mitigate a portion of this exposure, the Company enters into swaps and collars. For swap instruments, the Company receives a fixed price for the hedged commodity and pays a floating market price to the counterparty. The fixed-price payment and the floating-price payment are netted, resulting in a net amount due to or from the counterparty. Collars contain a fixed floor price (put) and ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, we receive the fixed price and pay the market price. If the market price is between the call and the put strike price, no payments are due from either party. The oil and natural gas reference prices upon which these price hedging instruments are based reflect various market indices that have a high degree of historical correlation with actual prices received by the Company.

All derivative financial instruments are recorded on the balance sheet at fair value. Fair value is generally determined based on the difference between the fixed contract price and the underlying forward market price at the determination date considering the time value of money. The fair value of our natural gas and oil swaps in effect at December 31, 2006 and 2007 was an asset of $1.2 million and a liability of $2.0 million, respectively.

Changes in the fair value of effective cash flow hedges are recorded as a component of accumulated other comprehensive income, which is later transferred to earnings when the hedged transaction occurs. As a result of the Company's hedging activities, the Company recognized $940,000 and $3.0 million of additional oil and natural gas sales for the years ended December 31, 2006 and 2007, respectively. There were no oil and natural gas hedging activities in 2005.

Based upon market prices at December 31, 2007, the Company expects to charge to earnings $1.7 million of the balance in accumulated other comprehensive income during the next 12 months when the forecasted transactions actually occur. All forecasted transactions hedged as of December 31, 2007 are expected to be settled by December 2009.

By using derivative instruments to hedge exposures to changes in commodity prices, the Company exposes itself to credit risk and market risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. To mitigate this risk, the hedging instruments are usually placed with counterparties that the Company believes are minimal credit risks.

Market risk is the adverse effect on the value of a derivative instrument that results from a change in interest rates or commodity prices. The market risk associated with commodity price is managed by establishing and monitoring parameters that limit the types and degree of market risk that may be undertaken.

NOTE D--LONG-TERM DEBT

Long-term debt consists of the following at December 31:

	2006	2007
	(in thousands)	
Revolving bank credit facility, maturity date of July 2011 bearing a variable weighted average interest rate of 7.45% and 6.88% as of December 31, 2006 and 2007, respectively, collateralized by oil and natural gas properties	$ 40,000	$ 89,860
Bridge Loan, maturity date of June 2008, bearing interest at prime rate plus 2.25% (effective rate of 9.5% at December 31, 2007)	---	4,140
Joint venture financing (non-recourse, no interest rate)	1,820	1,734
Series A Senior Subordinated Secured Notes due July 2012 with a fixed interest rate of 7.58% and secured by a second lien on all assets of GMX	---	30,000
	41,820	125,734
Less current maturities	251	4,321
	$ 41,569	$ 121,413

Maturities of long-term debt as of December 31, 2007 are as follows:

Year	Amount
(in thousands)	
2008	$ 4,321
2009	169
2010	155
2011	90,004
Thereafter	31,085
	$ 125,734

Revolving Bank Credit Facility

The Company has an executed loan agreement providing for a secured revolving line of credit up to an amount established as the borrowing base which is based on the Company's oil and natural gas reserves (the "Borrowing Base"). The loan bears interest at the rate elected by GMX of either the prime rate as published in the Wall Street Journal (payable monthly) or the LIBO rate plus a margin ranging from 1.5% to 2.25% based on the amount of the loan outstanding in relation to the Borrowing Base for a period of one, two or three months (payable at the end of such period). Principal is payable voluntarily by GMX or is required to be paid (i) if the loan amount exceeds the Borrowing Base; (ii) if the Lender elects to require periodic payments as a part of a Borrowing Base re-determination; and (ii) at the maturity date of July 15, 2011. GMX is obligated to pay a facility fee equal to 0.25% per year of the unused portion of the Borrowing Base payable quarterly. The Borrowing Base has been adjusted from time to time and was $90 million at December 31, 2007. The loan is secured by a first mortgage on substantially all of GMX's oil and natural gas properties, a pledge of our ownership of the stock of our subsidiaries, a guaranty from our subsidiaries and a security interest in all of the assets of our subsidiaries. The maximum amount GMX may borrow under the agreement is $125 million. The agreement contains various affirmative and restrictive covenants. These covenants among other things prohibit additional indebtedness, sales of assets, mergers and consolidations, dividends and distributions, changes in management and require the maintenance of various financial ratios. The financial ratios include maintaining a current ratio (as defined in the agreement) of not less than 1 to 1, a minimum net worth, and an EBITDA to cash interest expense and preferred dividends ratio of not less than 3 to 1.

In December 2007, the agreement was amended to grant a temporary increase in the Borrowing Base of $30 million (the "Bridge Loan") from the existing $90 million to $120 million until the earlier of the completion of additional financing or June 30, 2008. The Bridge Loan bears interest at a rate that is 2.25% higher per annum than our other borrowings under the normal Borrowing Base and the unused facility fee is 0.25% higher than the 0.25% fee for the normal Borrowing Base. In connection with the amendment, GMX paid an upfront commitment and arrangement fees of 2.5% of the Bridge Loan of $750,000. The amount of the Bridge Loan that bears interest and fees at the higher rates will be reduced by any increase in the GMX's regular borrowing base redetermination in April 2008. There were no other material changes to the existing loan agreement. The loan agreement was also amended in February 2008 to permit the sale of 5.00% Convertible Senior Notes due 2013.

Joint Venture Financing

In 2004, GMX entered into an arrangement with Penn Virginia Oil & Gas, L.P. ("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 GMX's 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. As of December 31, 2006 and 2007, the amount owed under this arrangement was $1.8 million and $1.7 million, respectively.

Secured Notes

In July 2007, GMX entered into a Note Purchase Agreement ("Note Agreement") with The Prudential Insurance Company of America ("Prudential") providing for the issuance and sale from time to time of up to $100 million in senior subordinated secured notes (the "Secured Notes") and sold to Prudential an initial tranche of $30 million of 7.58% Series A fixed rate notes due July 31, 2012 (the "Series A Notes") with interest payable quarterly. Proceeds from the sale of the Series A Notes was used for general corporate purposes including additional funding of drilling and development costs in the Cotton Valley Sands in East Texas. The Secured Notes are secured by a second lien on all of the assets of the company and its subsidiaries and are guaranteed by the company's subsidiaries, subject to the terms of an Intercreditor Agreement between our senior lenders and the collateral agent for the Noteholders, including Prudential. GMX amended the Note Agreement in February 2008 in connection with the sale of the 5.00% Senior Convertible Notes due 2013. The Agreement contains various affirmative and restrictive covenants. These covenants, among other things, prohibit additional indebtedness, sales of assets, mergers and consolidations, dividends and distributions, changes in management and require the maintenance of various financial ratios. The financial ratios include maintaining a minimum tangible net worth, a ratio of Adjusted PV10, as defined in the Note Agreement, to total debt of not less than 1.5 to 1, a ratio of total debt to EBITDA of not greater than 4.0 to 1, and a ratio of EBITDA to cash interest expenses (which is defined to include dividends on outstanding preferred stock) that may not be less than 2.5 to 1. As of December 31, 2007, the Company was in compliance with all the financial covenants of the Note Agreement.

In the event of a change in control, defined to be an acquisition of greater than 50% of GMX's outstanding voting stock (other than an acquisition by a public company meeting specified financial requirements) or change in management (defined as Ken L. Kenworthy, Jr. not being the chief executive officer for any reason, except that upon Mr. Kenworthy's death or disability, we have the ability to avoid a change in management if GMX names a successor chief executive officer acceptable to Prudential within four months), GMX is required to give notice to the Noteholders and offer to repurchase the Secured Notes at the outstanding principal amount plus accrued interest plus, in the case of any fixed rate notes, including the Series A Notes, a yield maintenance amount.

NOTE E – ASSET RETIREMENT OBLIGATIONS

The activity incurred in the asset retirement obligation is as follows for the years ended December 31:

	2006	2007
	(in thousands)	
Beginning balance	$ 2,212	$ 2,163
Liabilities incurred	337	1,188
Accretion[1]	32	178
Revisions[2]	(468)	96
Ending balance	2,163	3,625
Less current portion[3]	---	525
	$ 2,163	$ 3,100

[1] Annual accretion is added to the full cost pool.

[2] 2006 revisions were due to a decrease in the current inflation rate and an increase in the current interest rate. 2007 revisions were due to increases in the current inflation rate and interest rate.

[3] Current portion included in accrued expenses in the consolidated balance sheets.

The Company's liability for asset retirement obligations is included in other liabilities in the consolidated balance sheets, net of the current obligations.

NOTE F--INCOME TAXES

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

	2005	2006	2007
		(in thousands)	
Current tax expense	$ ---	$ ---	$ 33
Deferred tax expense	1,212	3,415	7,977
	$ 1,212	$ 3,415	$ 8,010

Total income tax expense 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:

	2005	2006	2007
U.S. statutory tax rate	34%	34%	34%
Statutory depletion	(12)	(4)	(4)
Change in valuation allowance	(8)	---	---
Other	---	(2)	2
Effective income tax rate	14%	28%	32%

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 also are recognized for operating losses that are available to offset future income taxes.

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

	2006	2007
	(in thousands)	
Deferred tax assets:		
Net operating loss carryforwards	$ 9,455	$ 10,561
Statutory depletion carryforwards	2,722	3,627
Stock option compensation expense	120	311
Unrealized loss on derivative instrument	---	680
Total	12,297	15,179
Deferred tax liabilities:		
Property, plant and equipment	(16,924)	(27,104)
Unrealized gain on derivative instrument	(400)	---
Total	(17,324)	(27,104)
Net deferred tax liability	$ (5,027)	$ (11,925)

At December 31, 2007, the Company had federal net operating loss carryforwards of $30.3 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, 2007, the Company had tax percentage depletion carryforwards of approximately $10.7 million which are not subject to expiration.

In assessing the realizability of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which the temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities, projected future taxable income, and tax planning strategies in making this assessment. Based primarily upon the level of projections for future taxable income and the reversal of future taxable differences over the period which the deferred tax assets are deductible, management believes it is more likely than not that the Company will realize the benefits of these deductible differences as of December 31, 2007.

NOTE G--COMMITMENTS AND CONTINGENCIES

The Company is party to various other 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.

The Company has entered into operating lease agreements for the use of office space and equipment. Rent expense for the years ended December 31, 2005, 2006, and 2007 was $119,000, $154,000 and $239,000, respectively.

The following is a schedule by year of future minimum rental payments required under operating leases that have initial or remaining non-cancelable lease terms in excess of one year as of December 31, 2007.

Year Ending December 31:

2008	$ 276,000
2009	275,000
2010	60,000
Total	$ 611,000

NOTE H—STOCK OPTION PLAN

In October 2000, the board of directors and shareholders adopted the GMX Resources Inc. Stock Option Plan (the "Option Plan"). Under the 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 Option Plan, as amended in May 2007, is 850,000, subject to appropriate adjustment in the event of a reorganization, stock split, stock dividend, reclassification or other change affecting the Company's common stock. All executive officers and other key employees who hold positions of significant responsibility are eligible to receive awards under the Option Plan. In addition, each director of the Company is eligible to receive options under the 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.

The board of directors may amend or terminate the Option Plan at any time, except that no amendment will become effective without the approval of the shareholders except to the extent such approval may be required by applicable law or by the rules of any securities exchange upon which the Company shares are admitted to listed trading. The Option Plan will terminate in 2010, except with respect to awards then outstanding.

The following table provides information related to stock option activity for the years ended December 31, 2005, 2006 and 2007:

	Number of shares	Weighted average exercise price
Balance as of December 31, 2004	314,000	$ 3.67
Granted	137,000	16.58
Exercised	(128,250)	2.69
Balance as of December 31, 2005	322,750	$ 8.65
Granted	53,000	35.31
Exercised	(102,500)	5.42
Forfeited	(3,000)	27.91
Balance as of December 31, 2006	270,250	$ 14.89
Granted	336,000	38.14
Exercised	(25,750)	3.00
Forfeited	(6,000)	31.27
Balance as of December 31, 2007	574,500	$ 28.86

At December 31, 2007, there were 114,500 exercisable options with weighted average exercise price of $13.40.

The weighted-average remaining contractual life of outstanding and exercisable options at December 31, 2007 was 8.5 and 5.6 years, respectively.

The aggregate intrinsic value of outstanding options and exercisable options at December 31, 2007 was $2.0 million and $2.4 million, respectively. The intrinsic value is the amount by which the market value of the underlying stock at December 31, 2007 exceeds the exercise price.

The aggregate intrinsic value of stock options exercised during the years 2005, 2006, and 2007 was approximately $1.4 million, $3.3 million and $798,000, respectively.

GMX received $77,250 in cash for option exercises in 2007. No current tax benefits were realized due to availability of a net operating loss carryforward for tax purposes, but deferred tax liability was reduced by $191,000.

As of December 31, 2007 there was $5.5 million 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 of 3.1 years.

The weighted-average grant-date fair value of options granted during the years 2005, 2006, and 2007 was $12.64, $21.38 and $14.46, respectively.

The fair value of all options granted have been based on the Black Scholes Option pricing model based on the assumptions of an expected life of four years, an expected dividend yield of 0%, risk free interest rates ranging from 1% to 4.95% depending on the date of grant, and stock price volatility calculated at the date of grant ranging from 39% to 144%.

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.

NOTE I--CAPITAL STOCK

The Company's Class A warrants issued in our initial public offering in 2001 allowed holders to purchase 1,250,000 common shares at $12.00 per share and expired in February 2006. In 2006, prior to the expiration of the warrants, we received approximately $14 million in exercise proceeds and issued an additional 1,164,326 shares of common stock.

In February 2007, the Company completed a public offering of 2,000,000 shares of our common stock for $34.82 per share. Net proceeds to the Company were approximately $65.6 million, which the Company used to fund drilling and development of our East Texas properties and for other general corporate purposes. Pending such uses, a portion of the net proceeds from this offering was used to reduce indebtedness under our revolving bank credit facility.

In August 2006, GMX sold 2,000,000 shares of 9.25% Series B Cumulative Preferred Stock at $25.00 per share in a public offering, resulting in a total offering of $50 million. The net proceeds of $47.1 million from the sale of preferred stock was used to fund the drilling and development of the Company's East Texas properties and for other general corporate purposes.

The annual dividend on each share of Series B Cumulative Preferred Stock is $2.3125 (an aggregate of $4.6 million) and is payable quarterly when, as and if declared by the Company, 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 Company's common stock and can be redeemed at the Company's option after September 30, 2011 at $25.00 per share. The Series B Cumulative Preferred Stock will be required to be redeemed prior to September 30, 2011 at specified redemption prices and thereafter at $25.00 per share in the event of a change of ownership or control of the Company if the acquirer is not a public company meeting certain financial criteria.

NOTE J--FINANCIAL INSTRUMENTS AND CONCENTRATIONS OF CREDIT RISK

FAIR VALUE OF FINANCIAL INSTRUMENTS: The Company's financial instruments consist of cash, accounts receivable, accounts payable, accrued expenses, revenue distributions payable, short and long-term debt, and oil and natural gas price swaps and collars. Fair value of non-derivative financial instruments approximate carrying value due to the short-term nature of these instruments. Since the interest rate on the long-term debt under the revolving bank credit facility reprices frequently, the fair value of this long-term debt approximates the carrying value. At December 31, 2007, the estimated fair value of Series A Senior Subordinated Secured Notes was approximately $35 million.

Fair value amounts have been estimated using available market information and valuation methodologies. The use of different market assumptions or valuation methodologies may have a material effect on the estimated fair value amounts.

CONCENTRATION OF CREDIT RISK: Financial instruments which potentially subject the Company to concentrations of credit risk consist principally of derivative instruments and accounts receivable. By using derivative instruments to hedge exposures to changes in commodity prices, the Company exposes itself to credit risk and market risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. To mitigate this risk, the hedging instruments are usually placed with counterparties that the Company believes are minimal credit risks.

Market risk is the adverse effect on the value of a derivative instrument that results from a change in interest rates or commodity prices. The market risk associated with commodity price is managed by establishing and monitoring parameters that limit the types and degree of market risk that may be undertaken.

Accounts receivable are primarily from purchasers of oil and natural gas production and exploration and production companies who own interests in properties the Company operates. The industry concentration has the potential to impact the Company's overall exposure to credit risk, either positively or negatively, in that customers may be similarly affected by changes in economic, industry, or other conditions.

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

	2005	2006	2007
Oil			
Various purchasers through PVOG	27%	44%	44%
Teppco Crude	65%	48%	55%
Natural Gas			
CrossTex Energy Services, Inc.	44%	42%	52%
Various purchasers through PVOG	48%	48%	45%

If the Company were to lose a purchaser, we believe we could replace them with a substitute purchaser with substantially equivalent terms.

NOTE K—RETIREMENT PLANS

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 employees gross wages. The Company contributed $43,000, $87,000 and $115,000 in 2005, 2006 and 2007, respectively.

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:

	2005	2006	2007
		(in thousands)	
Property acquisition costs – unproved	$ 1,256	$ 598	$ 1,018
Development costs	25,211	104,657	177,523
	$ 26,467	$ 105,255	$ 178,541

Unproved properties include unevaluated leaseholds. Of the $2.1 million of unproved property costs at December 31, 2007 being excluded from the amortization base, $288,000, $383,000 and $1.2 million were incurred in 2005, 2006, and 2007, respectively and $239,000 was incurred in prior years. 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 three years. The Company did not have any exploration or development costs not subject to amortization at December 31, 2006 or 2007, respectively.

Development costs include the cost of drilling and equipping development wells and constructing related production facilities for extracting, treating, gathering, and storing oil and natural gas from proved reserves.

The Company's results of operations include revenues and expenses associated directly with oil and natural gas producing activities and were as follows for the years ended December 31:

	2005	2006	2007
		(in thousands)	
Oil and natural gas sales	$ 19,026	$ 31,882	$ 67,883
Production costs	(3,311)	(4,944)	(11,728)
Depreciation, depletion and amortization	(3,497)	(6,882)	(16,382)
Income tax expense	(1,212)	(3,415)	(8,010)
Results of operations for oil and natural gas producing activities	$ 11,006	$ 16,641	$ 31,763

The average DD&A rate per equivalent unit of production was $1.58, $1.59 and $1.88 for the years ended December 31, 2005, 2006 and 2007, respectively.

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

The oil and natural gas reserve quantity information presented below is unaudited and is based upon reports prepared by independent petroleum engineers. The information is presented in accordance with regulations prescribed by the Securities and Exchange Commission. The Company emphasizes that reserve estimates are inherently imprecise. The Company's reserve estimates were estimated by performance methods, volumetric methods, and comparisons with analogous wells, where applicable. The reserves estimated by the performance method utilized extrapolations of historical production data. Reserves were estimated by the volumetric or analogous methods in cases where the historical production data was insufficient to establish a definitive trend. Accordingly, these estimates are expected to change, and such changes could be material and occur in the near term as future information becomes available.

Proved oil and natural gas reserves represent the estimated quantities of crude oil, natural gas, and natural gas liquids 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 oil and natural gas reserves are those expected to be recovered through existing wells with existing equipment and operating methods. As of

December 31, 2005, 2006 and 2007, all of the Company's oil and natural gas reserves were located in the United States.

	OIL (MBBLS)	GAS (MMCF)
December 31, 2005		
Proved reserves, beginning of period	1,237	56,922
Extensions, discoveries, and other additions	694	84,026
Production	(48)	(1,930)
Revisions of previous estimates	84	10,951
Proved reserves, end of period	1,967	149,969
Proved developed reserves:		
Beginning of period	584	18,978
End of period	764	41,161
December 31, 2006		
Proved reserves, beginning of period	1,967	149,969
Extensions, discoveries, and other additions	831	87,754
Production	(69)	(3,915)
Revisions of previous estimates	(36)	3,042
Proved reserves, end of period	2,693	236,850
Proved developed reserves:		
Beginning of period	764	41,161
End of period	932	69,279
December 31, 2007		
Proved reserves, beginning of period	2,693	236,850
Extensions, discoveries, and other additions	2,019	185,730
Production	(127)	(7,974)
Revisions of previous estimates	108	(8,264)
Proved reserves, end of period	4,693	406,342
Proved developed reserves:		
Beginning of period	932	69,279
End of period	1,776	144,164

The increase in proved reserves from extensions, discoveries, and other additions in each period is the direct result of additional drilling on the Company's acreage in East Texas, specifically the exploitation of the Cotton Valley formation. Over the past several years as the Company has drilled Cotton Valley wells, additional offsets have been proved (using SEC definitions of offset as only within one spacing unit of any existing producer or test). The revisions of previous estimates during 2005 and 2006 were the result of revised natural gas prices. The revision of previous estimates of natural gas reserves at year end 2007 were primarily related to decreases in proven undeveloped reserves presuming a 20 acre pattern of development.

Future cash inflows and future production and development costs are determined by applying year-end prices and costs to the estimated quantities of oil and natural gas to be produced. Estimates are made of quantities of proved reserves and the future periods during which they are expected to be produced based on year-end economic conditions. Estimated future income taxes are computed using current statutory income tax rates including consideration of the current tax bases of the properties and related carryforwards giving effect to permanent differences. The resulting future net cash flows are reduced to present value amounts by applying a 10% annual discount factor.

The assumptions used to compute the standardized measure are those prescribed by the Financial Accounting Standards Board, and, as such do not necessarily reflect the Company's expectations of actual revenue to be derived from those reserves nor their present worth. The limitations inherent in the reserve quantity estimation process, as discussed previously, are equally applicable to the standardized measure computations since these estimates are the basis for the valuation process.

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 prescribed in Statement of Financial Accounting Standards No. 69 as of December 31:

	2005	2006	2007
		(in thousands)	
Future cash inflows	$ 1,211,564	$ 1,337,671	$ 3,549,360
Future production costs	(327,958)	(508,221)	(1,097,465)
Future development costs	(190,700)	(309,907)	(555,623)
Future income tax provisions	(168,275)	(116,610)	(528,126)
Net future cash inflows	524,631	402,933	1,368,146
Less effect of a 10% discount factor	(339,111)	(268,499)	(940,416)
Standardized measure of discounted future net cash flows	$ 185,520	$ 134,434	$ 427,730

Oil and natural gas prices were based on a period end base prices, with adjustments to the base price for each lease for quality, contractual agreements, and regional price variations. Future income tax expenses are computed by applying the appropriate statutory rates to the future pre-tax net cash flows relating to proved reserves, net of the tax basis of the properties involved giving effect to permanent differences, tax credits, and allowances relating to proved oil and natural gas reserves.

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

	2005	2006	2007
		(in thousands)	
Standardized measure, beginning of year	$ 63,320	$ 185,520	$ 134,434
Sales of oil and natural gas, net of production costs	(15,714)	(26,938)	(53,131)
Net changes in prices and production costs	6,850	(110,559)	182,156
Change in estimated future development costs	(2,698)	(38,708)	75,335
Extensions and discoveries, net of future development costs	132,571	62,948	172,308
Previously estimated development cost incurred	23,629	104,707	30,977
Revisions of quantity estimates	25,836	13,360	(17,257)
Accretion of discount	39,647	22,676	54,192
Changes in timing of production and other	(48,413)	(91,507)	(25,081)
Net changes in income taxes	(39,508)	12,935	(126,203)
Standardized measure, end of year	$ 185,520	$ 134,434	$ 427,730

NOTE N—QUARTERLY FINANCIAL DATA (UNAUDITED)

Summarized unaudited quarterly financial data for 2006 and 2007 are as follows:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
		(in thousands, except per share data)			
2007					
Revenues	$ 13,253	$ 16,519	$ 17,098	$ 21,239	$ 68,109
Income before income taxes	5,390	6,799	5,974	6,732	24,895
Net income	3,814	4,637	3,561	4,873	16,885
Net income applicable to common stock	2,658	3,481	2,404	3,717	12,260
Basic earnings per share[1]	.21	.26	.18	.28	.94
Diluted earnings per share[1]	.21	.26	.18	.28	.93
2006					
Revenues	$ 6,716	$ 6,494	$ 8,534	$ 10,289	$ 32,033
Income before income taxes	2,780	1,942	3,905	3,763	12,390
Net income	2,134	1,592	2,861	2,388	8,975
Net income applicable to common stock	2,134	1,592	2,219	1,231	7,176
Basic earnings per share[1]	0.20	0.14	0.20	0.11	0.65
Diluted earnings per share[1]	0.19	0.14	0.19	0.11	0.64

[1] The sum of the per share amounts per quarter does not equal the year due to the changes in the average number of common shares outstanding

NOTE O – SUBSEQUENT EVENT – CONVERTIBLE NOTE OFFERING

On February 15, 2008, the Company sold $125 million of 5.00% Convertible Senior Subordinated Notes due 2013. Net proceeds of approximately $121 million were used to repay all debt outstanding under the Company's revolving bank credit facility and for other general corporate purposes. GMX may reborrow under the revolving bank credit facility up to the Borrowing Base, currently $90 million, to fund drilling and development costs and for other general corporate purposes. 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.

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