CONCHO RESOURCES INC
Form 10-K
February 24, 2012
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UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

þ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2011

or

¨ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from to

Commission file number: 1-33615

Concho Resources Inc.

(Exact name of registrant as specified in its charter)

Delaware State or other jurisdiction of incorporation or organization	**76-0818600** (I.R.S. Employer Identification No.)
550 West Texas Avenue, Suite 100 **Midland, Texas** (Address of principal executive offices)	**79701** (Zip code)

(432) 683-7443

Registrant s telephone number, including area code

Securities Registered Pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, $0.001 par value	**New York Stock Exchange**

Securities Registered Pursuant to Section 12(g) of the Act: **None**

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

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

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 þ No ¨

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

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

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

Large accelerated filer	þ	Accelerated filer	¨
Non-accelerated filer	¨ (Do not check if a smaller reporting company)	Smaller reporting company	¨

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

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 price of such common equity, as of the last business day of the registrant s most recently completed second fiscal quarter:	$ 9,285,109,152
Number of shares of registrant s common stock outstanding as of February 21, 2012:	103,710,760

Documents Incorporated by Reference:

Portions of the registrant s definitive proxy statement for its 2011 Annual Meeting of Stockholders, which will be filed with the United States Securities and Exchange Commission within 120 days of December 31, 2011, are incorporated by reference into Part III of this report for the year ended December 31, 2011.

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

Various statements contained in or incorporated by reference into this report that express a belief, expectation, or intention, or that are not statements of historical fact, are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 (the Securities Act) and Section 21E of the Securities Exchange Act of 1934 (the Exchange Act). These forward-looking statements include statements, projections and estimates concerning our operations, performance, business strategy, oil and natural gas reserves, drilling program, capital expenditures, liquidity and capital resources, the timing and success of specific projects, outcomes and effects of litigation, claims and disputes, derivative activities and potential financing. Forward-looking statements are generally accompanied by words such as estimate, project, predict, believe, expect, anticipate, potential, could, may, foresee, plan, goal or other words that convey the uncertainty of future events. Forward-looking statements are not guarantees of performance. We have based these forward-looking statements on our current expectations and assumptions about future events. These statements are based on certain assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions and expected future developments as well as other factors we believe are appropriate under the circumstances. Actual results may differ materially from those implied or expressed by the forward-looking statements. These forward-looking statements speak only as of the date of this report, or if earlier, as of the date they were made. We disclaim any obligation to update or revise these statements unless required by securities law, and we caution you not to rely on them unduly. While our management considers these expectations and assumptions to be reasonable, they are inherently subject to significant business, economic, competitive, regulatory and other risks, contingencies and uncertainties relating to, among other matters, the risks discussed in Item 1A. Risk Factors, as well as those factors summarized below:

- sustained or further declines in the prices we receive for our oil and natural gas;
- uncertainties about the estimated quantities of oil and natural gas reserves;
- drilling and operating risks, including risks related to properties where we do not serve as the operator and risks related to hydraulic fracturing activities;
- the adequacy of our capital resources and liquidity including, but not limited to, access to additional borrowing capacity under our credit facility;
- the effects of government regulation, permitting and other legal requirements, including new legislation or regulation of hydraulic fracturing;
- difficult and adverse conditions in the domestic and global capital and credit markets;
- risks related to the concentration of our operations in the Permian Basin of Southeast New Mexico and West Texas;
- potential financial losses or earnings reductions from our commodity price management program;
- shortages of oilfield equipment, supplies, services and qualified personnel and increased costs for such equipment, supplies, services and personnel;

- risks and liabilities associated with acquired properties or businesses;
- uncertainties about our ability to successfully execute our business and financial plans and strategies;
- uncertainties about our ability to replace reserves and economically develop our current reserves;
- general economic and business conditions, either internationally or domestically or in the jurisdictions in which we operate;
- competition in the oil and natural gas industry; and
- uncertainty concerning our assumed or possible future results of operations.

Reserve engineering is a process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data and price and cost assumptions made by our reserve engineers. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, such revisions would change the schedule of any further production and development drilling. Accordingly, reserve estimates may differ from the quantities of oil and natural gas that are ultimately recovered.

PART I

Item 1. Business

General

Concho Resources Inc., a Delaware corporation (Concho, Company, we, us and our) formed in February 2006, is an independent oil and na gas company engaged in the acquisition, development and exploration of oil and natural gas properties. Our core operating areas are located in the Permian Basin region of Southeast New Mexico and West Texas, a large onshore oil and natural gas basin in the United States. The Permian Basin is one of the most prolific oil and natural gas producing regions in the United States and is characterized by an extensive production history, long reserve life, multiple producing horizons and enhanced recovery potential. We refer to our three core operating areas as the (i) New Mexico Shelf, where we primarily target the Yeso and Lower Abo formations, (ii) Delaware Basin, where we primarily target the Bone Spring formation (including the Avalon shale and the Bone Spring sands) and the Wolfcamp shale, and (iii) Texas Permian, where we primarily target the Wolfberry, a term applied to the combined Wolfcamp and Spraberry horizons. We intend to grow our reserves and production through development drilling and exploration activities on our multi-year project inventory and through acquisitions that meet our strategic and financial objectives.

Acquisitions

PDC Acquisition

In December 2011, we entered into a definitive agreement to acquire certain producing and non-producing assets in the Wolfberry trend in the Permian Basin from Petroleum Development Corporation (the PDC Acquisition) for approximately $175 million in cash, subject to customary purchase price adjustments. We estimated that the PDC Acquisition had approximately 12.5 MMBoe of proved reserves at November 1, 2011. Subject to customary closing conditions, we expect to close the PDC Acquisition in the first quarter of 2012 and fund it with borrowings under our credit facility.

Delaware Basin Acquisitions

OGX Acquisition. In November 2011, we acquired three entities affiliated with OGX Holdings II, LLC (collectively the OGX Acquisition) for cash consideration of approximately $252 million, subject to customary post-closing adjustments. The OGX Acquisition consisted of producing and non-producing acreage in the Delaware Basin of Southeast New Mexico and West Texas. The OGX Acquisition contained approximately 5.7 MMBoe of proved reserves at closing. The OGX Acquisition was primarily funded with borrowings under our credit facility.

Other Delaware Basin Acquisitions. In the third and fourth quarters of 2011, in four acquisitions, we acquired for approximately $79 million, in cash, additional non-producing acreage in the Delaware Basin. These acquisitions were primarily funded with borrowings under our credit facility. We collectively refer to these acquisitions and the OGX Acquisition as the Delaware Basin Acquisitions.

Marbob and Settlement Acquisitions

In July 2010, we entered into an asset purchase agreement to acquire certain of the oil and natural gas leases, interests, properties and related assets owned by Marbob Energy Corporation and its affiliates (collectively, Marbob) for aggregate consideration of (i) cash in the amount of $1.45 billion, (ii) the issuance to Marbob of a $150 million 8.0% senior note due 2018, which was repaid in May of 2011 with borrowings under our credit facility, and (iii) the issuance to Marbob of approximately 1.1 million shares of our common stock, subject to purchase price adjustments, which included downward purchase price adjustments based on the exercise of third parties of contractual preferential purchase rights in properties to be acquired from Marbob (the Marbob Acquisition).

On October 7, 2010, we closed the Marbob Acquisition. At closing, we paid approximately $1.1 billion in cash plus the senior note and common stock described above for a total purchase price of approximately $1.4 billion. The total purchase price as originally announced was reduced due to third party contractual preferential purchase rights in the Marbob properties. Certain of the third parties contractual preferential purchase rights became subject to litigation, as discussed below.

We funded the cash consideration in the Marbob Acquisition with (a) borrowings under our credit facility and (b) net proceeds of $292.7 million from a private placement of approximately 6.6 million shares of our common stock at a price of $45.30 per share that closed on October 7, 2010.

Certain of the Marbob interests in properties contained contractual preferential purchase rights by third parties if Marbob were to sell them. Marbob informed us of its receipt of a notice from BP America Production Company (BP) electing to exercise its contractual preferential purchase rights.

On July 20, 2010, BP announced it was selling all its assets in the Permian Basin to a subsidiary of Apache Corporation (Apache). Marbob and BP owned common interests in certain properties subject to contractual preferential purchase rights. BP and Apache contested Marbob s ability to exercise its contractual preferential purchase rights in this situation. As a result, we and Marbob filed suit against BP and Apache seeking declaratory judgment and injunctive relief to protect Marbob s contractual right to have the option to purchase the interests in these common properties.

On October 15, 2010, we and Marbob resolved the litigation with BP and Apache related to the disputed contractual preferential purchase rights. As a result of the settlement, we acquired a non-operated interest in substantially all of the oil and natural gas assets subject to the litigation for approximately $286 million in cash (the Settlement Acquisition). We funded the Settlement Acquisition with borrowings under our credit facility.

The properties acquired in the Marbob and Settlement Acquisitions are primarily located in the Permian Basin of Southeast New Mexico, including a large acreage position contiguous to our core Yeso play on the southeast New Mexico Shelf and a significant acreage position in the Delaware Basin. The assets acquired in the Marbob and Settlement Acquisitions contained approximately 72.4 MMBoe of proved reserves at closing.

Wolfberry Acquisitions

In December 2009, together with the acquisition of related additional interests that closed in early 2010, we closed two acquisitions of interests in producing and non-producing assets in the Wolfberry play in Texas for approximately $270.7 million in cash (the Wolfberry Acquisitions). The Wolfberry Acquisitions contained approximately 19.9 MMBoe of proved reserves at closing. The Wolfberry Acquisitions were primarily funded with borrowings under our credit facility.

Divestitures

In March 2011, we sold our Bakken assets for cash consideration of approximately $195.9 million and recognized a pre-tax gain on the disposition of assets (included in discontinued operations) of approximately $135.9 million. For the first quarter of 2011, these assets produced an average of 1,369 Boe per day. The proved reserves of the Bakken assets at closing were approximately 8.4 MMBoe.

In December 2010, we sold certain of our non-core Permian Basin assets for cash consideration of approximately $103.3 million and recognized a pre-tax gain on the disposition of assets (included in discontinued operations) of approximately $29.1 million. For 2010, these assets produced an average of 1,393 Boe per day. The proved reserves of these assets were approximately 6.0 MMBoe at closing.

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Business and Properties

Our core operations are focused in the Permian Basin of Southeast New Mexico and West Texas. It underlies an area of Southeast New Mexico and West Texas approximately 250 miles wide and 300 miles long. Commercial accumulations of hydrocarbons occur in multiple stratigraphic horizons, at depths ranging from approximately 1,000 feet to over 25,000 feet. At December 31, 2011, substantially all of our total estimated proved reserves were located in our core operating areas and consisted of approximately 61.7 percent oil and 38.3 percent natural gas. We have assembled a multi-year inventory of development drilling and exploration projects, including projects to further evaluate (i) the areal extent of the Yeso formation and the Wolfberry play and (ii) the Bone Spring and Wolfcamp formations in the Delaware Basin and the Lower Abo horizontal oil play, which we believe will allow us to grow proved reserves and production.

We continually evaluate opportunities that could develop into an emerging play. We view an emerging play as an area where we can acquire large undeveloped acreage positions and apply horizontal drilling and/or advanced fracture stimulation technologies to achieve economic and repeatable production results. We have assembled an exploration team to target such emerging plays.

The following table sets forth information with respect to drilling of wells commenced during the periods indicated:

	Years Ended December 31,		
	2011	**2010**	**2009**
Gross wells	810	662	361
Net wells	574	402	230
Percent of gross wells:			
Producers	86.0%	76.0%	81.7%
Unsuccessful	0.0%	0.2%	0.6%
Awaiting completion at year-end	14.0%	23.8%	17.7%
	100.0%	100.0%	100.0%

We produced approximately 23.6 MMBoe, 15.6 MMBoe and 10.9 MMBoe of oil and natural gas during 2011, 2010 and 2009, respectively. Included in those production amounts are 123 MBoe, 995 MBoe and 775 MBoe of production related to our discontinued operations during 2011, 2010 and 2009, respectively. In addition, we increased our average daily production from 54.4 MBoe during the fourth quarter of 2010 to 71.0 MBoe during the fourth quarter of 2011. During 2011, we increased our total estimated proved reserves by approximately 63.1 MMBoe, including (i) acquisitions of 12.6 MMBoe and (ii) sales of minerals-in-place of 8.4 MMBoe.

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Summary of Core Operating Areas and Other Plays

The following is a summary of information regarding our core operating areas and other plays that are further described below:

	December 31, 2011									Year Ended	
Areas	**Total Proved Reserves (MBoe)**	**PV-10 ($ in millions)**		**% Oil**	**% Proved Developed**	**Gross Identified Drilling Locations**		**Total Gross Acreage**	**Total Net Acreage**	**December 31, 2011 Average Daily Production (Boe per Day)**	
Core Operating Areas:											
New Mexico Shelf	210,268	$ 5,083.3		64.5%	69.8%	2,715		240,404	124,278	35,666	
Delaware Basin	49,749	904.9		37.8%	53.9%	1,870		410,877	273,225	12,574	
Texas Permian	126,492	2,411.4		66.2%	49.3%	4,320		279,427	110,706	16,185	
Other	12	0.2		7.7%	100.0%			38,318	25,300	353	
Total	386,521	$ 8,399.8	(a)	61.7%	61.0%	8,905	(b)	969,026	533,509	64,778	(c)

(a) Our Standardized Measure at December 31, 2011 was $5.7 billion. The present value of estimated future net revenues discounted at an annual rate of 10 percent (PV-10) is not a GAAP financial measure and is derived from the Standardized Measure, which is the most directly comparable GAAP financial measure. PV-10 is a computation of the Standardized Measure on a pre-tax basis. PV-10 is equal to the Standardized Measure at the applicable date, before deducting future income taxes, discounted at 10 percent. We believe that the presentation of the PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to our estimated proved reserves prior to taking into account future corporate income taxes, and it is a useful measure for evaluating the relative monetary significance of our oil and natural gas assets. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies. We use this measure when assessing the potential return on investment related to our oil and natural gas assets. PV-10, however, is not a substitute for the Standardized Measure. Our PV-10 measure and the Standardized Measure do not purport to present the fair value of our oil and natural gas reserves. See Item 1. Business Non-GAAP Financial Measures and Reconciliations.

(b) Of the 8,905 gross identified drilling locations, 2,253 locations were associated with proved reserves.

(c) Includes production of 123 MBoe (an average of 1,369 Boe per day for the first quarter of 2011) for the Bakken assets divested in March 2011.

Core operating areas

New Mexico Shelf. This area represents our most significant concentration of assets and, at December 31, 2011, we had estimated proved reserves in this area of 210.3 MMBoe, representing 54.4 percent of our total proved reserves and 60.5 percent of our PV-10.

Within this area we target two distinct producing areas, which we refer to as the shelf assets and the Lower Abo assets. The shelf assets generally produce out of vertical wells from the Yeso, San Andres and Grayburg formations, with producing depths ranging from approximately 900 feet to 7,500 feet. The Lower Abo is a horizontal oil play just north and northeast of the shelf assets in Lea, Eddy and Chaves Counties, New Mexico. The Lower Abo play is found at vertical depths ranging from 6,500 feet to 10,000 feet and is being developed utilizing horizontal drilling techniques and advanced fracture and stimulation technology. We have drilled and plan to continue to evaluate drilling horizontally in the Yeso.

During the year ended December 31, 2011, we commenced drilling or participated in the drilling of 443 (360 net) wells in this area, of which 393 (320 net) wells were completed as producers and 50 (40 net) wells were in various stages of drilling and completion at December 31, 2011. During 2011, we continued our development of the Yeso formation on 10 acre spacing.

At December 31, 2011, we had 240,404 gross (124,278 net) acres in this area. At December 31, 2011, on our assets in this area, we had identified 2,715 (1,739 net) drilling locations, with proved undeveloped reserves attributed to 740 (550 net) of such locations. Of these drilling locations, we identified 1,955 (1,129 net) drilling locations intended to target the Yeso formation.

In 2012, we plan to spend approximately $496 million, or 36 percent, of our 2012 capital budget on drilling and completion costs on the New Mexico Shelf assets, with which we expect to drill 392 (279 net) wells.

Delaware Basin. At December 31, 2011, we had estimated proved reserves in the Delaware Basin, our newest core area, of 49.7 MMBoe, representing 12.9 percent of our total proved reserves and 10.8 percent of our PV-10. In 2011, we made the Delaware Basin Acquisitions for approximately $331 million and continued to actively acquire undeveloped leasehold acreage in the Delaware Basin.

Within this area, we utilize horizontal drilling and fracturing technologies to target the oil-prone Bone Spring formation that includes three Bone Spring sandstone members and the Avalon Shale member. Additionally, we utilize vertical drilling and multistage fracturing to target the oil prone Wolfbone formation, a new emerging opportunity that is a combination of stacked unconventional reservoir intervals of the Bone Spring formation and the Wolfcamp shale formation. These formations produce from 4,700 feet to 13,500 feet for our currently targeted activity. Within the Delaware Basin, we are also actively evaluating the Delaware sands, the Wolfcamp shale and Penn shale opportunities on our acreage.

During the year ended December 31, 2011, we commenced drilling or participated in the drilling of 87 (47 net) wells in this area, of which 61 (31 net) wells were completed as producers and 26 (15 net) wells were in various stages of drilling and completion at December 31, 2011. During 2011, we (i) continued our development and step-out activity on the Avalon Shale and Bone Springs sands, (ii) continued to evaluate our fracture stimulation procedures in the completion of certain horizontal wells, and (iii) drilled 11 wells to evaluate the effectiveness of modern fracture stimulation procedures in the Wolfbone formation.

At December 31, 2011, we had 410,877 gross (273,225 net) acres in this area. At December 31, 2011, we had identified 1,870 (1,005 net) drilling locations, with proved undeveloped reserves attributed to 157 (78 net) of such locations. Of these locations, we identified 1,417 (686 net) drilling locations to target the Bone Spring formation and 364 (276 net) drilling locations to target the Wolfbone formation.

In 2012, we plan to spend approximately $420 million, or 31 percent, of our 2012 capital budget on drilling and completion costs on the Delaware Basin assets, with which we expect to drill 136 (72 net) wells.

Texas Permian. At December 31, 2011, our estimated proved reserves of 126.5 MMBoe in this area accounted for 32.7 percent of our total proved reserves and 28.7 percent of our PV-10 value.

Our primary objective in the Texas Permian area is the Wolfberry in the Midland Basin. Wolfberry is the term applied to the combined production from the Spraberry and Wolfcamp horizons out of vertical wellbores, which are typically encountered at depths of 7,500 feet to 10,500 feet. These formations are comprised of a sequence of basinal, interbedded sands, shales and carbonates. We also operate and develop properties on the Central Basin Platform targeting the Grayburg, San Andres and Clearfork formations, which are shallower, and are typically encountered at depths of 4,500 feet to 7,500 feet. The reservoirs in these formations are largely carbonates, limestones and dolomites. On our Texas Permian assets we are (i) continuing to evaluate our 20- acre downspacing on the Wolfberry assets, (ii) evaluating the potential of horizontal Wolfcamp drilling and (iii) evaluating the other potential zones that are in our acreage, such as those in the Pennsylvanian age formations.

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At December 31, 2011, we had 279,427 gross (110,706 net) acres in this area. In addition, at December 31, 2011, we had identified 4,320 (2,119 net) drilling locations, with proved undeveloped reserves attributed to 1,327 (629 net) of such drilling locations. Included in the 4,320 identified drilling locations are 2,498 (1,246 net) 20-acre drilling locations.

During 2011, we commenced drilling or participated in the drilling of 272 (167 net) wells in this area, of which 225 (141 net) wells were completed as producers, no wells were unsuccessful and 47 (26 net) wells were in various stages of drilling and completion at December 31, 2011.

In 2012, we plan to spend approximately $336 million, or 25 percent, of our 2012 capital budget on drilling and completion costs on the Texas Permian assets, with which we expect to drill 353 (186 net) wells.

Drilling Activities

The following table sets forth information with respect to (i) wells drilled and completed during the periods indicated and (ii) wells drilled in a prior period but completed in the periods indicated. The information should not be considered indicative of future performance, nor should a correlation be assumed between the number of productive wells drilled, quantities of reserves found or economic value.

	Years Ended December 31,					
	2011		2010		2009	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive	503	371	402	253	211	139
Dry			1			
Exploratory wells:						
Productive	331	209	164	91	125	83
Dry			1		3	1
Total wells:						
Productive	834	580	566	344	336	222
Dry			2		3	1
Total	834	580	568	344	339	223

The following table sets forth information about our wells for which drilling was in-progress or are pending completion at December 31, 2011, which are not included in the above table.

	Drilling In-Progress		Pending Completion	
	Gross	Net	Gross	Net
Development wells	18	11	46	34
Exploratory wells	12	8	48	29
Total	30	19	94	63

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Our Production, Prices and Expenses

The following table sets forth summary information concerning our production and operating data from continuing operations for the years ended December 31, 2011, 2010 and 2009. The table below excludes production and operating data that we have classified as discontinued operations, which is more fully described in Note O of the Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data. The actual historical data in this table excludes results from the (i) OGX Acquisition for periods prior to December 2011, (ii) Marbob and Settlement Acquisitions for periods prior to their respective close dates in October 2010 and (iii) Wolfberry Acquisitions for periods prior to 2010. Because of normal production declines, increased or decreased drilling activities and the effects of acquisitions or divestitures, the historical information presented below should not be interpreted as being indicative of future results.

	Years Ended December 31,		
	2011	**2010**	**2009**
Production and operating data:			
Net production volumes:			
Oil (MBbl)	14,575	9,621	6,874
Natural gas (MMcf)	53,677	29,687	19,692
Total (MBoe)	23,521	14,569	10,156
Average daily production volumes:			
Oil (Bbl)	39,932	26,359	18,833
Natural gas (Mcf)	147,060	81,334	53,951
Total (Boe)	64,442	39,915	27,825
Average prices:			
Oil, without derivatives (Bbl)	$ 91.29	$ 76.43	$ 58.12
Oil, with derivatives (Bbl) [(a)]	$ 84.16	$ 73.70	$ 69.00
Natural gas, without derivatives (Mcf)	$ 7.63	$ 6.90	$ 5.65
Natural gas, with derivatives (Mcf) [(a)]	$ 8.11	$ 7.49	$ 6.21
Total, without derivatives (Boe)	$ 73.98	$ 64.54	$ 50.29
Total, with derivatives (Boe) [(a)]	$ 70.65	$ 63.93	$ 58.74
Operating costs and expenses per Boe:			
Lease operating expenses and workover costs	$ 7.08	$ 5.94	$ 5.51
Oil and natural gas taxes	$ 6.02	$ 5.48	$ 4.09
General and administrative	$ 4.09	$ 4.37	$ 5.24
Depreciation, depletion and amortization	$ 18.21	$ 16.59	$ 18.89

(a) Includes the effect of cash settlements received from (paid on) commodity derivatives not designated as hedges and reported in operating costs and expenses. The following table reflects the amounts of cash settlements received from (paid on) commodity derivatives not designated as hedges that were included in computing average prices with derivatives and reconciles to the amount in loss on derivatives not designated as hedges as reported in the statements of operations:

	Years Ended December 31,		
(in thousands)	**2011**	**2010**	**2009**
Loss on derivatives not designated as hedges:			

Cash (payments on) receipts from oil derivatives	$ (103,969)	$ (26,281)	$ 74,796
Cash receipts from natural gas derivatives	25,739	17,414	10,955
Cash payments on interest rate derivatives	(6,624)	(4,957)	(3,335)
Unrealized mark-to-market gain (loss) on commodity and interest rate derivatives	61,504	(73,501)	(239,273)
Loss on derivatives not designated as hedges	$ (23,350)	$ (87,325)	$ (156,857)

The presentation of average prices with derivatives is a non-GAAP measure as a result of including the cash (payments on) receipts from commodity derivatives that are presented in loss on derivatives not designated as hedges in the statements of operations. This presentation of average prices with derivatives is a means by which to reflect the actual cash performance of our commodity derivatives for the respective periods and presents oil and natural gas prices with derivatives in a manner consistent with the presentation generally used by the investment community.

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Productive Wells

The following table sets forth the number of productive oil and natural gas wells on our properties at December 31, 2011, 2010 and 2009. Certain prior period counts have been adjusted to conform to the 2011 core area presentation. This table does not include wells in which we own a royalty interest only.

	Gross Productive Wells			Net Productive Wells		
	Oil	Natural Gas	Total	Oil	Natural Gas	Total
December 31, 2011						
Core Operating Areas:						
New Mexico Shelf	2,757	114	2,871	2,181	46	2,227
Delaware Basin	416	319	735	212	124	336
Texas Permian	1,893	5	1,898	781	3	784
Total	5,066	438	5,504	3,174	173	3,347
December 31, 2010						
Core Operating Areas:						
New Mexico Shelf	2,309	83	2,392	1,847	39	1,886
Delaware Basin	319	256	575	146	102	248
Texas Permian	1,587	4	1,591	595	3	598
Other	88		88	11		11
Total	4,303	343	4,646	2,599	144	2,743
December 31, 2009						
Core Operating Areas:						
New Mexico Shelf	1,464	68	1,532	1,047	30	1,077
Delaware Basin	300	123	423	133	25	158
Texas Permian	1,740	69	1,809	464	11	475
Other	65	131	196	6	6	12
Total	3,569	391	3,960	1,650	72	1,722

Marketing Arrangements

General. We market our oil and natural gas in accordance with standard energy practices utilizing certain of our employees and external consultants, in each case in consultation with our products group, asset managers and our corporate reservoir engineers. The marketing effort is coordinated with our operations group as it relates to the planning and preparation of future drilling programs so that available markets can be assessed and secured. This planning also involves the coordination of access to the physical facilities necessary to connect new producing wells as efficiently as possible upon their completion.

Oil. We do not transport, refine or process the oil we produce. A significant portion of our oil in Southeast New Mexico is connected directly to oil gathering pipelines. Most of our gathered oil in this area is utilized in a two-refinery complex in Southeast New Mexico. A significant portion of our West Texas production is on pipeline. Most of this production is sweet crude and is transported by third parties to the Cushing, Oklahoma hub. The balance of our oil in these areas that is not directly connected to pipeline is (i) trucked to unloading stations on those same pipelines or (ii) railed to the Gulf Coast in lieu of transporting by pipeline. We sell the majority of the oil we produce under contracts using market-based pricing. This price is then adjusted for differentials based upon delivery location and oil quality.

Natural Gas. We consider all natural gas gathering and delivery infrastructure in the areas of our production and evaluate market options to obtain the best price reasonably available under the circumstances. We sell the majority of our natural gas under individually negotiated natural gas purchase contracts using market-based pricing. The majority of our natural gas is subject to term agreements that extend at least three years from the date of the subject contract.

The majority of the natural gas we sell is casinghead gas sold at the lease under a percentage of proceeds processing contract. The purchaser gathers our casinghead natural gas in the field where it is produced and transports it via pipeline to a natural gas processing plant where the natural gas liquid products are extracted and sold by the processor. The remaining natural gas product is residue gas, or dry gas, which is placed on residue pipeline systems available in the area. Under our percentage of proceeds contracts, we receive a percentage of the value for the extracted liquids and the residue gas. In a limited number of cases (typically dry gas production), the natural gas gathering and transportation is performed by a third party gathering company which transports the production from the production location to the purchaser s mainline.

Our Principal Customers

We sell our oil and natural gas production principally to marketers and other purchasers that have access to pipeline facilities. In areas where there is no practical access to pipelines, oil is transported to storage facilities by trucks owned or otherwise arranged by the marketers or purchasers. Our marketing of oil and natural gas can be affected by factors beyond our control, the effects of which cannot be accurately predicted.

For 2011, revenues from oil and natural gas sales to Holly Frontier Refining and Marketing, LLC (formerly, Navajo Refining Company, L.P.), ConocoPhillips Company and DCP Midstream, LP accounted for approximately 34 percent, 15 percent and 14 percent, respectively, of our total operating revenues. While the loss of any of these purchasers may result in a temporary interruption in sales of, or a lower price for, our production, we believe that the loss of any of these purchasers would not have a material adverse effect on our operations, as there are alternative purchasers in our producing regions.

Competition

The oil and natural gas industry in the regions in which we operate is highly competitive. We encounter strong competition from numerous parties, ranging generally from small independent producers to major integrated companies. We primarily encounter significant competition in acquiring properties, contracting for drilling and workover equipment and securing trained personnel. Many of these competitors have financial and technical resources and staffs substantially larger than ours. As a result, our competitors may be able to pay more for desirable properties, or to evaluate, bid for and purchase a greater number of properties or prospects than our financial or personnel resources will permit.

In addition to competition for drilling and workover equipment, we are also affected by the availability of related equipment and materials. The oil and natural gas industry periodically experiences shortages of drilling and workover rigs, equipment, pipe, materials and personnel, which can delay drilling, workover and exploration activities and cause significant price increases. The shortages of personnel make it difficult to attract and retain personnel with experience in the oil and natural gas industry and caused us to increase our general and administrative budget. We are unable to predict the timing or duration of any such shortages.

Competition is also strong for attractive oil and natural gas producing properties, undeveloped leases and drilling rights. Although we regularly evaluate acquisition opportunities and submit bids as part of our growth strategy, we do not have any current agreements, understandings or arrangements with respect to any material acquisition.

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Applicable Laws and Regulations

Regulation of the Oil and Natural Gas Industry

Regulation of transportation and sale of oil. Sales of oil, condensate and natural gas liquids are not currently regulated and are made at negotiated prices. Nevertheless, Congress could reenact price controls in the future.

Our sales of oil are affected by the availability, terms and cost of transportation. The transportation of oil in common carrier pipelines is also subject to rate regulation. The Federal Energy Regulatory Commission (the FERC) regulates interstate oil pipeline transportation rates under the Interstate Commerce Act. In general, interstate oil pipeline rates must be cost-based, although settlement rates agreed to by all shippers are permitted and market-based rates may be permitted in certain circumstances. Effective January 1, 1995, the FERC implemented regulations establishing an indexing system that permits an oil pipeline, subject to limited challenges, to annually increase or decrease its transportation rates due to inflationary changes in costs using a FERC approved index, without making a cost of service filing. Every five years, the FERC reviews the appropriateness of the index in relation to industry costs. On March 21, 2006, FERC issued a decision setting the index for the period July 1, 2006 through July 1, 2011 at the Producer Price Index for Finished Goods (the PPI-FG) plus 1.3 percent. Most recently, on December 16, 2010, the FERC established a new price index of PPI-FG plus 2.65 percent for the five-year period beginning July 1, 2011. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any way that is of material difference from those of our competitors.

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis at posted tariff rates. When oil pipelines operate at full capacity, access is governed by prorationing provisions set forth in the pipelines published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our competitors.

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

Regulation of transportation and sale of natural gas. Historically, the transportation and sale for resale of natural gas in interstate commerce have been regulated pursuant to the Natural Gas Act of 1938 (the Natural Gas Act), the Natural Gas Policy Act of 1978 (the Natural Gas Policy Act) and regulations issued under those acts by the FERC. In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at uncontrolled market prices, Congress could reenact price controls in the future, and market participants are prohibited from engaging in market manipulation. Deregulation of wellhead natural gas sales began with the enactment of the Natural Gas Policy Act. In 1989, Congress enacted the Natural Gas Wellhead Decontrol Act which removed all Natural Gas Act and Natural Gas Policy Act price and non-price controls affecting wellhead sales of natural gas effective January 1, 1993.

The FERC regulates interstate natural gas transportation rates and service conditions, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas. Since 1985, the FERC has endeavored to make natural gas transportation more accessible to natural gas buyers and sellers on an open and non-discriminatory basis. The FERC has stated that open access policies are necessary to improve the competitive structure of the interstate natural gas pipeline industry and to create a regulatory framework that will put natural gas sellers into more direct contractual relations with natural gas buyers by, among other things, unbundling the sale of natural gas from the sale of transportation and storage services. Beginning in 1992, the FERC issued Order No. 636 and a series of related orders to implement its open access policies. As a result of the Order No. 636 program, the marketing and pricing of natural gas have been significantly altered. The interstate pipelines traditional role as wholesalers of natural gas has been eliminated and replaced by a structure under which pipelines provide transportation and storage service on an open access basis to others who buy and sell natural gas. Although these orders do not directly regulate natural gas producers, they are intended to foster increased competition within all phases of the natural gas industry.

In 2000, the FERC issued Order No. 637 and subsequent orders, which imposed a number of additional reforms designed to enhance competition in natural gas markets. Among other things, Order No. 637 effected changes in FERC regulations relating to scheduling procedures, capacity segmentation, penalties, rights of first refusal and information reporting.

In August 2005, Congress enacted the Energy Policy Act of 2005 (the EPAct 2005). Among other matters, EPAct 2005 amends the Natural Gas Act to make it unlawful for any entity, including otherwise non-jurisdictional producers such as us, to use any deceptive or manipulative device or contrivance in connection with the purchase or sale of natural gas or the purchase or sale of transportation services subject to regulation by the FERC, in contravention of rules prescribed by the FERC. The FERC s rules implementing this provision make it unlawful, in connection with the purchase or sale of natural gas subject to the jurisdiction of the FERC, or the purchase or sale of transportation services subject to the jurisdiction of the FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or to engage in any act or practice that operates as a fraud or deceit upon any person. EPAct 2005 also gives the FERC authority to impose civil penalties for violations of the Natural Gas Act or Natural Gas Policy Act up to $1 million per day per violation. The new anti-manipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sales, gathering or production, but does apply to activities of otherwise non-jurisdictional entities to the extent the activities are conducted in connection with natural gas sales, purchases or transportation subject to FERC jurisdiction, which now includes the annual reporting requirements under Order No. 704, described below. EPAct 2005 therefore reflects a significant expansion of the FERC s enforcement authority. We do not anticipate we will be affected any differently than other producers of natural gas.

In December 2007, the FERC issued a rule (Order No. 704), as clarified in orders on rehearing, requiring that any market participant, including a producer such as us, that engages in wholesale sales or purchases of natural gas that equal or exceed 2.2 million MMBtus during a calendar year to annually report, starting May 1, 2009, such sales and purchases to the FERC. These rules are intended to increase the transparency of the wholesale natural gas markets and to assist the FERC in monitoring such markets and in detecting market manipulation. We do not anticipate that we will be affected by these rules any differently than other producers of natural gas.

We cannot accurately predict whether the FERC s actions will achieve the goal of increasing competition in markets in which our natural gas is sold. Additional proposals and proceedings that might affect the natural gas industry are pending before the FERC and the courts. The natural gas industry historically has been very heavily regulated. Therefore, we cannot provide any assurance that the less stringent regulatory approach recently established by the FERC will continue. However, we do not believe that any action taken will affect us in a way that materially differs from the way it affects other natural gas producers.

Gathering service, which occurs upstream of jurisdictional transmission services, is regulated by the states onshore and in state waters. Although its policy is still in flux, the FERC has reclassified certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, which has the tendency to increase our costs of getting natural gas to point of sale locations.

Intrastate natural gas transportation is also subject to regulation by state regulatory agencies. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. During the 2007 legislative session, the Texas State Legislature passed H.B. 3273 (the Competition Bill) and H.B. 1920 (the LUG Bill). The Competition Bill gives the Railroad Commission of Texas the ability to use either a cost-of-service method or a market-based method for setting rates for natural gas gathering and intrastate transportation pipelines in formal rate proceedings. It also gives the Railroad Commission specific authority to enforce its statutory duty to prevent discrimination in natural gas gathering and transportation, to enforce the requirement that parties participate in an informal complaint process and to punish purchasers, transporters, and gatherers for taking discriminatory actions against shippers and sellers. The Competition Bill also provides producers with the unilateral option to determine whether or not confidentiality provisions are included in a contract to which a producer is a party for the sale, transportation or gathering of natural gas. The LUG Bill modifies the informal complaint process at the Railroad Commission with procedures unique to lost and unaccounted for natural gas issues. It extends the types of information that can be requested, provides producers with an annual audit right, and provides the Railroad Commission with the authority to make determinations and issue orders in specific situations. Both the Competition Bill and the LUG Bill became effective September 1, 2007, and the Railroad Commission rules implementing the Railroad Commission s authority pursuant to the bills became effective on April 28, 2008.

Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is of material difference from those of our competitors. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas.

Regulation of production. The production of oil and natural gas is subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations. Federal, state and local statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. All of the states in which we own and operate properties have regulations governing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum allowable rates of production from oil and natural gas wells, the regulation of well spacing, and the plugging and abandonment of wells. The effect of these regulations is to limit the amount of oil and natural gas that we can produce from our wells and to limit the number of wells or the locations at which we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction. The failure to comply with these rules and regulations can result in substantial penalties. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

Environmental, Health and Safety Matters

General. Our operations are subject to stringent and complex federal, state and local laws and regulations governing environmental protection as well as the discharge of materials into the environment. These laws and regulations may, among other things:

- require the acquisition of various permits before drilling commences;
- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with oil and natural gas drilling and production and saltwater disposal activities;

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- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; and

- require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells.

These laws, rules and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and natural gas industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, environmental laws and regulations are revised frequently, and any changes that result in more stringent and costly waste handling, disposal and cleanup requirements for the oil and natural gas industry could have a significant impact on our operating costs.

The following is a summary of some of the existing laws, rules and regulations to which our business is subject.

Waste handling. The Resource Conservation and Recovery Act (the RCRA) and comparable state statutes, regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Under the auspices of the federal Environmental Protection Agency (the EPA), the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters, and most of the other wastes associated with the exploration, development, and production of oil or natural gas are currently regulated under RCRA s non-hazardous waste provisions. However, it is possible that certain oil and natural gas exploration and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. Any such change could result in an increase in our costs to manage and dispose of wastes, which could have a material adverse effect on our results of operations and financial position.

Comprehensive Environmental Response, Compensation and Liability Act. The Comprehensive Environmental Response, Compensation and Liability Act (the CERCLA), also known as the Superfund law, imposes joint and several liability, without regard to fault or legality of conduct, on classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include the owner or operator of the site where the release occurred, and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. In addition, 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 currently own, lease, or operate numerous properties that have been used for oil and natural gas exploration and production for many years. Although we believe that we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes or hydrocarbons may have been released on or under the properties owned or leased by us, or on or under other locations, including off-site locations, where such substances have been taken for disposal. In addition, some of our properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes or hydrocarbons was not under our control. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to remove previously disposed substances and wastes, remediate contaminated property, or perform remedial operations to prevent future contamination.

Water discharges. The federal Water Pollution Control Act (the Clean Water Act) and analogous state laws, impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States. The discharge of pollutants into regulated waters is

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prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations.

Air emissions. The federal Clean Air Act (CAA), and comparable state laws, regulate emissions of various air pollutants through air emissions permitting programs and the imposition of other requirements. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions of toxic air pollutants at specified sources. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the CAA and associated state laws and regulations.

For example, on July 28, 2011, the EPA issued proposed rules that would subject all oil and gas operations (production, processing, transmission, storage and distribution) to regulation under the New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAPS) programs. The EPA proposed rules also include NSPS standards for completions of hydraulically fractured gas wells. These standards include the reduced emission completion (REC) techniques developed in EPA s Natural Gas STAR program along with pit flaring of gas not sent to the gathering line. The standards would be applicable to newly drilled and fractured wells as well as existing wells that are refractured. Further, the proposed regulations under NESHAPS include maximum achievable control technology (MACT) standards for those glycol dehydrators and storage vessels at major sources of hazardous air pollutants not currently subject to MACT standards. We are currently evaluating the effect these proposed rules could have on our business. EPA has indicated that it intends to adopt a final version of the proposed rules sometime in the spring of 2012.

Climate change. In December 2009, the EPA determined that emissions of carbon dioxide, methane and other greenhouse gases , or GHGs, present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth s atmosphere and other climatic changes. Based on these findings, the EPA has begun adopting and implementing regulations to restrict emissions of GHGs under existing provisions of the CAA. The EPA recently adopted two sets of rules regulating GHG emissions under the CAA, one of which requires a reduction in emissions of GHGs from motor vehicles and the other of which regulates emissions of GHGs from certain large stationary sources, effective January 2, 2011. The EPA s rules relating to emissions of GHGs are currently subject to a number of legal challenges, but the federal courts have thus far declined to issue any injunctions to prevent EPA from implementing, or requiring state environmental agencies to implement, the rules. The EPA has also adopted rules requiring the reporting of GHG emissions from specified large GHG emission sources in the United States, including petroleum refineries, on an annual basis beginning in 2011 for emissions occurring after January 1, 2010, as well as certain onshore oil and natural gas facilities, on an annual basis beginning in 2012 for emissions occurring in 2011.

In addition, Congress has from time to time considered adopting legislation to reduce emissions of GHGs and almost one-half of the states have already taken legal measures to reduce emissions of GHGs gases primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and natural gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall GHG emission reduction goal.

The adoption of legislation or regulatory programs to reduce emissions of GHGs could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances, or to comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Consequently, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on our business, financial condition and results of operations. Finally, it should be noted that some

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scientists have concluded that increasing concentrations of GHGs in the earth s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations.

Hydraulic fracturing. Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand, and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. We commonly use hydraulic fracturing as part of our operations. Hydraulic fracturing typically is regulated by state oil and natural gas commissions, but the EPA has asserted federal regulatory authority pursuant to the Safe Drinking Water Act over certain hydraulic fracturing activities involving the use of diesel. In addition, legislation has been introduced before Congress to provide for federal regulation of hydraulic fracturing under the Safe Drinking Water Act and to require disclosure of the chemicals used in the hydraulic fracturing process. At the state level, several states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure, and well construction requirements on hydraulic fracturing activities. For example, Texas adopted rules requiring public disclosure of non-confidential information regarding fluids used in hydraulic fracturing activities that became effective on February 1, 2012, and New Mexico adopted similar rules that became effective on February 15, 2012. We believe that we follow applicable standard industry practices and legal requirements for groundwater protection in our hydraulic fracturing activities. Nonetheless, if new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

In addition, certain governmental reviews are either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and a committee of the United States House of Representatives has conducted an investigation of hydraulic fracturing practices. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with initial results expected to be available by late 2012 and final results by 2014. Moreover, the EPA is developing effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities and plans to propose these standards by 2014. Other governmental agencies, including the United States Department of Energy and the United States Department of the Interior, are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the federal Safe Drinking Water Act or other regulatory mechanisms

To our knowledge, there have been no citations, suits, or contamination of potable drinking water arising from our fracturing operations. We do not have insurance policies in effect that are intended to provide coverage for losses solely related to hydraulic fracturing operations; however, we believe our general liability and excess liability insurance policies may cover third-party claims related to hydraulic fracturing operations and associated legal expenses in accordance with, and subject to, the terms of such policies.

Endangered species. The federal Endangered Species Act and analogous state laws regulate activities that could have an adverse effect on threatened or endangered species. Some of our drilling operations are conducted in areas where protected species are known to exist. In these areas, we may be obligated to develop and implement plans to avoid potential adverse impacts to protected species, and we may be prohibited from conducting drilling operations in certain locations or during certain seasons, such as breeding and nesting seasons, when our operations could have an adverse effect on the species. It is also possible that a federal or state agency could order a complete halt to drilling activities in certain locations if it is determined that such activities may have a serious adverse effect on a protected species. The presence of a protected species in areas where we

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perform drilling activities could impair our ability to timely complete drilling and developmental operations and could adversely affect our future production from those areas.

National Environmental Policy Act. Oil and natural gas exploration and production activities on federal lands are subject to the National Environmental Policy Act (the NEPA). NEPA requires federal agencies, including the Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an environmental assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed environmental impact statement that may be made available for public review and comment. All of our current exploration and production activities, as well as proposed exploration and development plans, on federal lands require governmental permits that are subject to the requirements of NEPA. This process has the potential to delay or even halt development of some of our oil and natural gas projects.

OSHA and other laws and regulation. We are subject to the requirements of the federal Occupational Safety and Health Act (OSHA), and comparable state statutes. The OSHA hazard communication standard, the EPA community right-to-know regulations under the Title III of CERCLA and similar state statutes require that we organize and/or disclose information about hazardous materials used or produced in our operations. Also, pursuant to OSHA, the Occupational Safety and Health Administration has established a variety of standards relating to workplace exposure to hazardous substances and employee health and safety. We believe that we are in substantial compliance with the applicable requirements of OSHA and comparable laws.

We believe that we are in substantial compliance with existing environmental laws and regulations applicable to our current operations and that our continued compliance with existing requirements will not have a material adverse impact on our financial condition and results of operations. For instance, we did not incur any material capital expenditures for remediation or pollution control activities during 2011. Additionally, as of the date of this report, we are not aware of any environmental issues or claims that will require material capital expenditures during 2012. However, we cannot assure you that the passage or application of more stringent laws or regulations in the future will not have a negative impact on our financial position or results of operation.

Our Employees

Our corporate headquarters are located at 550 W. Texas Avenue, Suite 100, Midland, Texas 79701. We also maintain various field offices in Texas and New Mexico. At December 31, 2011, we had 592 employees, 215 of whom were employed in field operations. Our future success will depend partially on our ability to attract, retain and motivate qualified personnel. We are not a party to any collective bargaining agreements and have not experienced any strikes or work stoppages. We consider our relations with our employees to be good. We also utilize the services of independent contractors to perform various field and other services.

Available Information

We file or furnish annual, quarterly and current reports, proxy statements and other documents with the United States Securities and Exchange Commission (the SEC) under the Exchange Act. The public may read and copy any materials that we file or furnish 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 on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Also, the SEC maintains a website that contains reports, proxy and information statements, and other information regarding issuers, including us, that file or furnish electronically with the SEC. The public can obtain any documents that we file with the SEC at *www.sec.gov*.

We also make available free of charge through our website, *www.concho.com*, our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and, if applicable, amendments to those reports filed or furnished pursuant to Section 13(a) of the Exchange Act as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC.

Non-GAAP Financial Measures and Reconciliations

PV-10

PV-10 is derived from the standardized measure of discounted future net cash flows, which is the most directly comparable GAAP financial measure. PV-10 is a computation of the standardized measure of discounted future net cash flows on a pre-tax basis. PV-10 is equal to the standardized measure of discounted future net cash flows at the applicable date, before deducting future income taxes, discounted at 10 percent. We believe that the presentation of PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to our estimated proved reserves prior to taking into account future corporate income taxes, and it is a useful measure for evaluating the relative monetary significance of our oil and natural gas assets. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies. We use this measure when assessing the potential return on investment related to our oil and natural gas assets. PV-10, however, is not a substitute for the standardized measure of discounted future net cash flows. Our PV-10 measure and the standardized measure of discounted future net cash flows do not purport to present the fair value of our oil and natural gas reserves.

The following table provides a reconciliation of PV-10 to the standardized measure of discounted future net cash flows at December 31, 2011, 2010 and 2009:

	December 31,		
(in millions)	**2011**	**2010**	**2009**
PV-10	$ 8,399.8	$ 6,061.2	$ 2,764.8
Present value of future income taxes discounted at 10%	(2,698.7)	(1,885.1)	(842.8)
Standardized measure of discounted future net cash flows	$ 5,701.1	$ 4,176.1	$ 1,922.0

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EBITDAX

We define EBITDAX as net income (loss), plus (1) exploration and abandonments expense, (2) depreciation, depletion and amortization expense, (3) accretion expense, (4) impairments of long-lived assets, (5) non-cash stock-based compensation expense, (6) bad debt expense, (7) ineffective portion of cash flow hedges, (8) unrealized (gain) loss on derivatives not designated as hedges, (9) (gain) loss on sale of assets, net, (10) interest expense, (11) federal and state income taxes on continuing operations and (12) similar items listed above that are presented in discontinued operations. EBITDAX is not a measure of net income or cash flow as determined by GAAP.

Our EBITDAX measure provides additional information which may be used to better understand our operations, and it is also a material component of one of the financial covenants under our credit facility. EBITDAX is one of several metrics that we use as a supplemental financial measurement in the evaluation of our business and should not be considered as an alternative to, or more meaningful than, net income, as an indicator of our operating performance. Certain items excluded from EBITDAX are significant components in understanding and assessing a company s financial performance, such as a company s cost of capital and tax structure, as well as the historic cost of depreciable and depletable assets. EBITDAX, as used by us, may not be comparable to similarly titled measures reported by other companies. We believe that EBITDAX is a widely followed measure of operating performance and is one of many metrics used by our management team and by other users of our consolidated financial statements, including by lenders pursuant to a covenant in our credit facility. For example, EBITDAX can be used to assess our operating performance and return on capital in comparison to other independent exploration and production companies without regard to financial or capital structure, and to assess the financial performance of our assets and our company without regard to capital structure or historical cost basis. Further, under our credit facility, an event of default could arise if we were not able to satisfy and remain in compliance with specified financial ratios, including the maintenance of a quarterly ratio of total debt to consolidated last twelve months EBITDAX of no greater than 4.0 to 1.0. Non-compliance with this ratio could trigger an event of default under our credit facility, which then could trigger an event of default under our indentures.

The following table provides a reconciliation of net income (loss) to EBITDAX:

	Years Ended December 31,				
(in thousands)	**2011**	**2010**	**2009**	**2008**	**2007**
Net income (loss)	$ 548,137	$ 204,370	$ (9,802)	$ 278,702	$ 25,360
Exploration and abandonments	11,779	10,324	10,632	38,468	29,097
Depreciation, depletion and amortization	428,377	241,642	191,889	113,668	69,327
Accretion of discount on asset retirement obligations	2,965	1,482	909	759	360
Impairments of long-lived assets	439	11,614	7,880	8,382	4,393
Non-cash stock-based compensation	19,271	12,931	9,040	5,223	3,841
Bad debt expense	-	870	(1,035)	2,905	-
Ineffective portion of cash flow hedges	-	-	-	(1,336)	821
Unrealized (gain) loss on derivatives not designated as hedges	(61,504)	73,501	239,273	(256,224)	22,089
(Gain) loss on sale of assets, net	1,139	58	114	(777)	(368)
Interest expense	118,360	60,087	28,292	29,039	36,042
Income tax expense (benefit) on continuing operations	285,848	115,278	(22,589)	158,125	12,799
Discontinued operations	(79,652)	10,837	20,605	24,369	13,631
EBITDAX	$ 1,275,159	$ 742,994	$ 475,208	$ 401,303	$ 217,392

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Item 1A. Risk Factors

You should consider carefully the following risk factors together with all of the other information included in this report and other reports filed with the SEC, before investing in our shares. If any of the following risks were actually to occur, our business, financial condition or results of operations could be materially adversely affected. In that case, the trading price of our shares could decline and you could lose all or part of your investment.

Risks Related to Our Business

Oil and natural gas prices are volatile. A decline in oil and natural gas prices could adversely affect our financial position, financial results, cash flow, access to capital and ability to grow.

Our future financial condition, revenues, results of operations, rate of growth and the carrying value of our oil and natural gas properties depend primarily upon the prices we receive for our oil and natural gas production and the prices prevailing from time to time for oil and natural gas. Oil and natural gas prices historically have been volatile, and are likely to continue to be volatile in the future, especially given current geopolitical conditions. This price volatility also affects the amount of cash flow we have available for capital expenditures and our ability to borrow money or raise additional capital. The prices for oil and natural gas are subject to a variety of factors beyond our control, including:

- the level of consumer demand for oil and natural gas;
- the domestic and foreign supply of oil and natural gas;
- liquefied natural gas deliveries to and from the United States;
- commodity processing, gathering and transportation availability and the availability of refining capacity;
- the overall global demand for oil;
- overall North American natural gas supply and demand fundamentals;
- the price and level of imports of foreign oil and natural gas;
- the ability of the members of the Organization of Petroleum Exporting Countries and other exporting nations to agree to and maintain oil price and production controls;
- domestic and foreign governmental regulations and taxes;
- the price and availability of alternative fuel sources;
- weather conditions;

political conditions or hostilities in oil and natural gas producing regions, including the Middle East, Africa and South America;

technological advances affecting energy consumption;

variations between product prices at sales points and applicable index prices; and

worldwide economic conditions.

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Furthermore, oil and natural gas prices continued to be volatile in 2011. For example, the NYMEX oil prices in 2011 ranged from a high of $113.93 to a low of $75.67 per Bbl and the NYMEX natural gas prices in 2011 ranged from a high of $4.85 to a low of $2.99 per MMBtu. Further, the NYMEX oil prices and NYMEX natural gas prices reached lows of $96.36 per Bbl and $2.32 per MMBtu, respectively, during the period from January 1, 2012 to February 21, 2012.

Declines in oil and natural gas prices would not only reduce our revenue, but could also reduce the amount of oil and natural gas that we can produce economically. This in turn would lower the amount of oil and natural gas reserves we could recognize and, as a result, could have a material adverse effect on our financial condition and results of operations. If the oil and natural gas industry experiences significant price declines, we may, among other things, be unable to maintain or increase our borrowing capacity, repay current or future indebtedness or obtain additional capital on attractive terms, all of which can adversely affect the value of our securities.

Drilling for and producing oil and natural gas are high-risk activities with many uncertainties that could cause our expenses to increase or our cash flows and production volumes to decrease.

Our future financial condition and results of operations will depend on the success of our exploration and production activities. Our oil and natural gas exploration and production activities are subject to numerous risks, including the risk that drilling will not result in commercially viable oil or natural gas production. Our decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. Our cost of drilling, completing, equipping and operating wells is often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical or less economic than forecasted. Further, many factors may curtail, delay or cancel drilling, including the following:

- delays imposed by or resulting from compliance with regulatory and contractual requirements;
- pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment and qualified personnel;
- equipment failures or accidents;
- adverse weather conditions;
- reductions in oil and natural gas prices;
- surface access restrictions;
- loss of title or other title related issues;
- oil, natural gas liquids or natural gas gathering, transportation and processing availability restrictions or limitations; and
- limitations in the market for oil and natural gas.

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

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight formations. We routinely utilize hydraulic fracturing techniques in many of our drilling and completion programs. The process involves the injection of water, sand and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and natural gas commissions. However, the EPA recently asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the Safe Drinking Water Act s Underground Injection Control Program. While the EPA has yet to take any action to enforce or implement this newly asserted regulatory authority, industry groups have filed suit challenging the EPA s recent decision.

At the same time, the White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic-fracturing practices, and a committee of the United States House of Representatives has conducted an investigation of hydraulic fracturing practices. The EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities on drinking water and groundwater, with initial results expected to be available by late 2012 and final results by 2014. Also in December 2011, the EPA published a draft report finding that hydraulic fracturing is a likely cause of drinking water contamination in the vicinity of Pavillion, Wyoming. While we do not have operations in the Pavillion natural gas field, findings such as this could increase public pressure on governmental authorities to implement new regulations regarding hydraulic fracturing. In addition, the United States Department of Energy is conducting an investigation into practices the agency could recommend to better protect the environment from drilling using hydraulic-fracturing completion methods. Additionally, certain members of the Congress have called upon the United States Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources, the SEC to investigate the natural gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural gas deposits in shales by means of hydraulic fracturing, and the United States Energy Information Administration to provide a better understanding of that agency s estimates regarding natural gas reserves, including reserves from shale formations, as well as uncertainties associated with those estimates. Legislation also has been introduced before Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the Safe Drinking Water Act or other regulatory mechanism.

In addition, some states have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, disclosure and well construction requirements on hydraulic fracturing operations. For example, Colorado, Pennsylvania, and Wyoming have each adopted a variety of well construction, set back, and disclosure regulations limiting how fracturing can be performed and requiring various degrees of chemical disclosure. In addition, Texas adopted rules requiring public disclosure of non-confidential information regarding fluids used in hydraulic fracturing activities that became effective on February 1, 2012, and New Mexico adopted similar rules that became effective on February 15, 2012. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit the performance of drilling in general and/or hydraulic fracturing in particular. In the event state, local, or municipal legal restrictions are adopted in areas where we are currently conducting, or in the future plan to conduct operations, we may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from the drilling of wells.

Further, on July 28, 2011, the EPA issued proposed rules that would subject all oil and natural gas operations (production, processing, transmission, storage and distribution) to regulation under the NSPS and NESHAPS programs. The EPA proposed rules also include NSPS standards for completions of hydraulically fractured natural gas wells. These standards include the REC techniques developed in the EPA s Natural Gas STAR program along with pit flaring of natural gas not sent to the gathering line. The standards would be applicable to newly drilled and fractured wells as well as existing wells that are refractured. Further, the proposed regulations under NESHAPS include MACT standards for those glycol dehydrators and storage vessels at major sources of hazardous air pollutants not currently subject to MACT standards. We are currently evaluating the effect these proposed rules could have on our business. Final action on the proposed rules is expected in the spring of 2012.

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If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations. In addition, if hydraulic fracturing becomes regulated at the federal level as a result of federal legislation or regulatory initiatives by the EPA, our fracturing activities could become subject to additional permitting requirements, and also result in permitting delays and potential cost increases. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

Our operations are substantially dependent on the availability of water. Restrictions on our ability to obtain water may have an adverse effect on our financial condition, results of operations and cash flows.

Water is an essential component of both the drilling and hydraulic fracturing processes. Historically, we have been able to purchase water from local land owners and other sources for use in our operations. During 2011, West Texas and Southeast New Mexico experienced the lowest inflows of water in recent history. As a result of this severe drought, some local water districts may begin restricting the use of water subject to their jurisdiction for drilling and hydraulic fracturing in order to protect the local water supply. If we are unable to obtain water to use in our operations from local sources, we may be unable to economically produce oil and natural gas, which could have an adverse effect on our financial condition, results of operations and cash flows.

We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, timing, manner or feasibility of conducting our operations.

Our oil and natural gas exploration, development and production, and related saltwater disposal operations are subject to complex and stringent laws and regulations. In order to conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state, local and governmental authorities. We may incur substantial costs and experience delays in order to maintain compliance with these existing laws and regulations. In addition, our costs of compliance may increase or our operations may be otherwise adversely affected if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations. These and other costs could have a material adverse effect on our production, revenues and results of operations.

Our business is subject to federal, state and local laws and regulations as interpreted and enforced by governmental authorities possessing jurisdiction over various aspects of the exploration for, and the production of, oil and natural gas. Failure to comply with such laws and regulations, as interpreted and enforced, could have a material adverse effect on our production, revenues and results of operations.

Estimates of proved reserves and future net cash flows are not precise. The actual quantities of our proved reserves and our future net cash flows may prove to be lower than estimated.

Numerous uncertainties exist in estimating quantities of proved reserves and future net cash flows therefrom. Our estimates of proved reserves and related future net cash flows are based on various assumptions, which may ultimately prove to be inaccurate.

Petroleum engineering is a subjective process of estimating accumulations of oil and natural gas that cannot be measured in an exact manner. Estimates of economically recoverable oil and natural gas reserves and of future net cash flows depend upon a number of variable factors and assumptions, including the following:

- historical production from the area compared with production from other producing areas;
- the assumed effects of regulations by governmental agencies;
- the quality, quantity and interpretation of available relevant data;
- assumptions concerning future commodity prices; and

- assumptions concerning future operating costs; severance, ad valorem and excise taxes; development costs; and workover and remedial costs.

Because all reserve estimates are to some degree subjective, each of the following items, or other items not identified below, may differ materially from those assumed in estimating reserves:

- the quantities of oil and natural gas that are ultimately recovered;
- the production and operating costs incurred;
- the amount and timing of future development expenditures; and
- future commodity prices.

Furthermore, different reserve engineers may make different estimates of reserves and cash flows based on the same data. Our actual production, revenues and expenditures with respect to reserves will likely be different from estimates and the differences may be material.

The Standardized Measure of our estimated reserves is not an accurate estimate of the current fair value of our estimated proved oil and natural gas reserves.

Standardized Measure is a reporting convention that provides a common basis for comparing oil and natural gas companies subject to the rules and regulations of the SEC. Our non-GAAP financial measure, PV-10, is a similar reporting convention that we have disclosed in this report. Both measures require the use of operating and development costs prevailing as of the date of computation. Consequently, they will not reflect the prices ordinarily received or that will be received for oil and natural gas production because of varying market conditions, nor may it reflect the actual costs that will be required to produce or develop the oil and natural gas properties. Accordingly, estimates included herein of future net cash flows may be materially different from the future net cash flows that are ultimately received. In addition, the 10 percent discount factor, which is required by the rules and regulations of the SEC to be used in calculating discounted future net cash flows for reporting purposes, may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with our company or the oil and natural gas industry in general. Therefore, Standardized Measure or PV-10 included in this report should not be construed as accurate estimates of the current fair value of our proved reserves. Any adjustments to the estimates of proved reserves or decreases in the price of oil or natural gas may decrease the value of our securities.

If average oil prices were $10.00 per Bbl lower than the average price we used, our PV-10 at December 31, 2011 would have decreased from $8,399.8 million to $7,395.1 million. If average natural gas prices were $1.00 per Mcf lower than the average price we used, our PV-10 at December 31, 2011, would have decreased from $8,399.8 million to $7,749.6 million. Any adjustments to the estimates of proved reserves or decreases in the price of oil or natural gas may decrease the value of our securities.

Our business requires substantial capital expenditures. We may be unable to obtain needed capital or financing on satisfactory terms or at all, which could lead to a decline in our oil and natural gas reserves.

The oil and natural gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures for the acquisition, exploration and development of oil and natural gas reserves. At December 31, 2011, total debt outstanding under our credit facility was $583.5 million (and total debt at December 31, 2011 was $2.1 billion), and approximately $1.4 billion was available to be borrowed under our credit facility. Expenditures for exploration and development of oil and natural gas properties are the primary use of our capital resources. We incurred approximately $1.8 billion in acquisition, exploration and development activities (excluding asset retirement obligations) during the year ended December 31, 2011 on our properties ($0.5 billion of which was related to acquisitions). Under our 2012 capital budget, we currently intend to invest approximately $1.37 billion for exploration and development activities and customary acquisition of leasehold acreage.

We intend to finance our future capital expenditures, other than significant acquisitions, primarily through cash flow from operations and, if needed, through borrowings under our credit facility; however, our financing needs may require us to alter or increase our capitalization substantially through the issuance of debt or equity securities. The issuance of additional equity securities could have a dilutive effect on the value of our common stock. Additional borrowings under our credit facility or the issuance of additional debt securities will require that a greater portion of our cash flow from operations be used for the payment of interest and principal on our debt, thereby reducing our ability to use cash flow to fund working capital, capital expenditures and acquisitions. In addition, our credit facility imposes certain limitations on our ability to incur additional indebtedness other than indebtedness under our credit facility. If we desire to issue additional debt securities other than as expressly permitted under our credit facility, we will be required to seek the consent of the lenders in accordance with the requirements of the credit facility, which consent may be withheld by the lenders at their discretion. If we incur certain additional indebtedness, our borrowing base under our credit facility may be reduced. Additional financing also may not be available on acceptable terms or at all. In the event additional capital resources are unavailable, we may curtail drilling, development and other activities or be forced to sell some of our assets on an untimely or unfavorable basis.

Our cash flow from operations and access to capital are subject to a number of variables, including:

- our proved reserves;
- the level of oil and natural gas we are able to produce from existing wells;
- the prices at which our oil and natural gas are sold;
- global credit and securities markets;
- the ability and willingness of lenders and investors to provide capital and the cost of the capital; and
- our ability to acquire, locate and produce new reserves.

If our revenues or the borrowing base under our credit facility decrease as a result of lower oil or natural gas prices, operating difficulties, declines in reserves, lending requirements or regulations, or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels. As a result, we may require additional capital to fund our operations, and we may not be able to obtain debt or equity financing to satisfy our capital requirements. If cash generated from operations or borrowings available under our credit facility is not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to the development of our prospects, which in turn could lead to a decline in our oil and natural gas reserves, and could adversely affect our production, revenues and results of operations.

We have substantial indebtedness and may incur substantially more debt. Higher levels of indebtedness make us more vulnerable to economic downturns and adverse developments in our business.

We have debt amounting to approximately $2.1 billion at December 31, 2011. At December 31, 2011, the borrowing base under our credit facility was $2.5 billion and commitments from our bank group totaled $2.0 billion, of which approximately $1.4 billion was available to be borrowed.

As a result of our indebtedness, we will need to use a portion of our cash flow to pay interest, which will reduce the amount we will have available to fund our operations and other business activities and could limit our flexibility in planning for or reacting to changes in our business and the industry in which we operate. Our indebtedness under our credit facility is at a variable interest rate, and so a rise in interest rates will generate

greater interest expense to the extent we do not have applicable interest rate fluctuation hedges. The amount of our debt may also cause us to be more vulnerable to economic downturns and adverse developments in our business.

We may incur substantially more debt in the future. The indentures governing our outstanding senior notes contain restrictions on our incurrence of additional indebtedness. These restrictions, however, are subject to a number of qualifications and exceptions, and under certain circumstances, we could incur substantial additional indebtedness in compliance with these restrictions. Moreover, these restrictions do not prevent us from incurring obligations that do not constitute indebtedness under the indentures.

Our ability to meet our debt obligations and other expenses will depend on our future performance, which will be affected by financial, business, economic, regulatory and other factors, many of which we are unable to control. If our cash flow is not sufficient to service our debt, we may be required to refinance debt, sell assets or sell additional equity on terms that we may not find attractive if it may be done at all. Further, our failure to comply with the financial and other restrictive covenants relating to our indebtedness could result in a default under that indebtedness, which could adversely affect our business, financial condition and results of operations.

Our operations expose us to significant costs and liabilities with respect to environmental and operational safety matters.

We may incur significant delays, costs and liabilities as a result of environmental, health and safety requirements applicable to our oil and natural gas exploration, development and production, and related saltwater disposal activities. These delays, costs and liabilities could arise under a wide range of federal, state and local laws and regulations relating to protection of the environment, health and safety, including regulations and enforcement policies that have tended to become increasingly strict over time. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of cleanup and site restoration costs and liens, and, in some instances, issuance of orders or injunctions limiting or requiring discontinuation of certain operations. In addition, claims for damages to persons or property, including natural resources, may result from the environmental, health and safety impacts of our operations.

Strict as well as joint and several liability for a variety of environmental costs may be imposed under certain environmental laws, which could cause us to become liable for the conduct of others or for consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. New laws, regulations or enforcement policies could be more stringent and impose unforeseen liabilities or significantly increase compliance costs. If we were not able to recover the resulting costs through insurance or increased revenues, our production, revenues and results of operations could be adversely affected.

Our lenders can limit our borrowing capabilities, which may materially impact our operations.

At December 31, 2011, we had approximately $583.5 million of outstanding debt under our credit facility, and our borrowing base was $2.5 billion and commitments from our bank group totaled $2.0 billion. The borrowing base under our credit facility is semi-annually redetermined based upon a number of factors, including commodity prices and reserve levels. In addition, between redeterminations we and, if requested by 66 2/3 percent of our lenders, our lenders, may each request one special redetermination. Upon a redetermination, our borrowing base could be substantially reduced, and in the event the amount outstanding under our credit facility at any time exceeds the borrowing base at such time, we may be required to repay a portion of our outstanding borrowings. If we incur certain additional indebtedness, our borrowing base under our credit facility may be reduced. We expect to utilize cash flow from operations, bank borrowings, debt and equity financings and asset sales to fund our acquisition, exploration and development activities. A reduction in our borrowing base could limit our activities. In addition, we may significantly alter our capitalization in order to make future acquisitions or develop our properties. These changes in capitalization may significantly increase our level of debt. If we incur additional debt for these or other purposes, the related risks that we now face could intensify. A higher level of debt also increases the risk that we may default on our debt obligations. Our ability to meet our debt obligations and to reduce our level of debt depends on our future performance which is affected by general economic conditions and financial, business and other factors, many of which are beyond our control.

Our producing properties are located substantially in the Permian Basin of Southeast New Mexico and West Texas, making us vulnerable to risks associated with operating in one major geographic area. In addition, we have a large amount of proved reserves attributable to a small number of producing horizons within this area.

Our producing properties are geographically concentrated in the Permian Basin of Southeast New Mexico and West Texas. At December 31, 2011, substantially all of our total estimated proved reserves were attributable to properties located in this area. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints, market limitations, drought related conditions or interruption of the processing or transportation of oil, natural gas or natural gas liquids.

In addition to the geographic concentration of our producing properties described above, at December 31, 2011, approximately (i) 41.5 percent of our proved reserves were attributable to the Yeso formation, which includes both the Paddock and Blinebry intervals, underlying our oil and natural gas properties located in Southeast New Mexico; and (ii) 29.2 percent of our proved reserves were attributable to the Wolfberry play in West Texas. This concentration of assets within a small number of producing horizons exposes us to additional risks, such as changes in field-wide rules and regulations that could cause us to permanently or temporarily shut-in all of our wells within a field.

Future price declines could result in a reduction in the carrying value of our proved oil and natural gas properties, which could adversely affect our results of operations.

Declines in commodity prices may result in having to make substantial downward adjustments to our estimated proved reserves. If this occurs, or if our estimates of production or economic factors change, accounting rules may require us to write-down, as a noncash charge to earnings, the carrying value of our proved oil and natural gas properties for impairments. We are required to perform impairment tests on proved assets whenever events or changes in circumstances warrant a review of our proved oil and natural gas properties. To the extent such tests indicate a reduction of the estimated useful life or estimated future cash flows of our oil and natural gas properties, the carrying value may not be recoverable and therefore require a write-down. We may incur impairment charges in the future, which could materially adversely affect our results of operations in the period incurred.

We periodically evaluate our unproved oil and natural gas properties for impairment, and could be required to recognize noncash charges to earnings of future periods.

At December 31, 2011, we carried unproved property costs of $796.1 million. GAAP requires periodic evaluation of these costs on a project-by-project basis in comparison to their estimated fair value. These evaluations will be affected by the results of exploration activities, commodity price circumstances, planned future sales or expiration of all or a portion of the leases, contracts and permits appurtenant to such projects. If the quantity of potential reserves determined by such evaluations is not sufficient to fully recover the cost invested in each project, we will recognize noncash charges to earnings of future periods.

Part of our strategy involves exploratory drilling, including drilling in new or emerging plays. As a result, our drilling results in these areas are uncertain, and the value of our undeveloped acreage will decline if drilling results are unsuccessful.

The results of our exploratory drilling in new or emerging plays are more uncertain than drilling results in areas that are developed and have established production. Since new or emerging plays and new formations have limited or no production history, we are unable to use past drilling results in those areas to help predict our future drilling results. As a result, our cost of drilling, completing and operating wells in these areas may be higher than initially expected, and the value of our undeveloped acreage will decline if drilling results are unsuccessful.

Our commodity price risk management program may cause us to forego additional future profits or result in our making cash payments to our counterparties.

To reduce our exposure to changes in the prices of oil and natural gas, we have entered into and may in the future enter into additional commodity price risk management arrangements for a portion of our oil and natural gas production. The agreements that we have entered into generally have the effect of providing us with a fixed price for a portion of our expected future oil and natural gas production over a fixed period of time. Commodity price risk management arrangements expose us to the risk of financial loss and may limit our ability to benefit from increases in oil and natural gas prices in some circumstances, including the following:

- the counterparty to a commodity price risk management contract may default on its contractual obligations to us;
- there may be a change in the expected differential between the underlying price in a commodity price risk management agreement and actual prices received; or
- market prices may exceed the prices which we are contracted to receive, resulting in our need to make significant cash payments to our counterparties.

Our commodity price risk management activities could have the effect of reducing our revenues, net income and the value of our securities. At December 31, 2011, the net unrealized loss on our commodity price risk management contracts was approximately $78.8 million. An average increase in the commodity price of $10.00 per barrel of oil and $1.00 per MMBtu for natural gas from the commodity prices at December 31, 2011 would have increased the net unrealized loss on our commodity price risk management contracts, as reflected on our balance sheet at December 31, 2011, by $210.6 million. We may continue to incur significant unrealized gains or losses in the future from our commodity price risk management activities to the extent market prices increase or decrease and our derivatives contracts remain in place.

Our identified inventory of drilling locations and recompletion opportunities are scheduled out over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

We have identified and scheduled the drilling of certain of our drilling locations as an estimation of our future multi-year development activities on our existing acreage. At December 31, 2011, we had identified 8,905 gross drilling locations, with proved reserves attributable to 2,253 of such locations. These identified locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including (i) our ability to timely drill wells on lands subject to complex development terms and circumstances; (ii) the availability of capital, equipment, services and personnel; (iii) seasonal conditions; (iv) regulatory and third party approvals; (v) oil and natural gas prices; and (vi) drilling and recompletion costs and results. Because of these and other potential uncertainties, we may never drill the numerous potential locations we have identified or produce oil or natural gas from these or any other potential locations. As such, our actual development activities may materially differ from those presently identified, which could adversely affect our production, revenues and results of operations.

Approximately 39 percent of our total estimated proved reserves at December 31, 2011 were undeveloped, and those reserves may not ultimately be developed.

At December 31, 2011, approximately 39 percent of our total estimated proved reserves were undeveloped. Recovery of undeveloped reserves requires significant capital expenditures and successful drilling. Our reserve data assumes that we can and will make these expenditures and conduct these operations successfully. These assumptions, however, may not prove correct. Our reserve report at December 31, 2011 includes estimates of total future development costs over the next five years associated with our proved undeveloped reserves of approximately $2.4 billion. If we choose not to spend the capital to develop these reserves, or if we are not otherwise able to successfully develop these reserves, we will be required to write-off these reserves. In addition, under the SEC s reserve rules, because proved undeveloped reserves may be booked only if they relate to wells scheduled to be drilled within five years of the date of booking, we may be required to write off any proved undeveloped reserves that are not developed within this five year timeframe. Any such write-offs of our reserves could reduce our ability to borrow money and could reduce the value of our securities.

Unless we replace our oil and natural gas reserves, our reserves and production will decline, which would adversely affect our cash flow, our ability to raise capital and the value of our securities.

Unless we conduct successful development and exploration activities or acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future oil and natural gas reserves and production, and therefore our cash flow and results of operations, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. The value of our securities and our ability to raise capital will be adversely impacted if we are not able to replace our reserves that are depleted by production. We may not be able to develop, exploit, find or acquire sufficient additional reserves to replace our current and future production.

We may be unable to make attractive acquisitions or successfully integrate acquired companies or assets, and any inability to do so may disrupt our business and hinder our ability to grow.

One aspect of our business strategy calls for acquisitions of businesses or assets that complement or expand our current business. We may not be able to identify attractive acquisition opportunities. Even if we do identify attractive candidates, we may not be able to complete the acquisition of them or do so on commercially acceptable terms.

In addition, our credit facility and the indentures governing our senior notes impose certain limitations on our ability to enter into mergers or combination transactions. Our credit facility and the indentures governing our senior notes also limit our ability to incur certain indebtedness, which could indirectly limit our ability to engage in acquisitions of businesses or assets. If we desire to engage in an acquisition that is otherwise prohibited by our credit facility or the indentures governing our senior notes, we will be required to seek the consent of our lenders or the holders of the senior notes in accordance with the requirements of the credit facility or the indentures, which consent may be withheld by the lenders under our credit facility or such holders of senior notes at their sole discretion.

If we acquire another business or assets, we could have difficulty integrating its operations, systems, management and other personnel and technology with our own. These difficulties could disrupt our ongoing business, distract our management and employees, increase our expenses and adversely affect our results of operations. In addition, we may incur additional debt or issue additional equity to pay for any future acquisitions, subject to the limitations described above.

Our acquisitions may prove to be worth less than what we paid because of uncertainties in evaluating recoverable reserves and could expose us to potentially significant liabilities.

We obtained the majority of our current reserve base through acquisitions of producing properties and undeveloped acreage. We expect that acquisitions will continue to contribute to our future growth. In connection with these and potential future acquisitions, we are often only able to perform limited due diligence.

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Successful acquisitions of oil and natural gas properties require an assessment of a number of factors, including estimates of recoverable reserves, the timing of recovering reserves, exploration potential, future oil and natural gas prices, operating costs and potential environmental, regulatory and other liabilities. Such assessments are inexact, and we cannot make these assessments with a high degree of accuracy. In connection with our assessments, we perform a review of the acquired properties. However, such a review will not reveal all existing or potential problems. In addition, our review may not permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. We do not inspect every well. Even when we inspect a well, we do not always discover structural, subsurface and environmental problems that may exist or arise.

There may be threatened, contemplated, asserted or other claims against the acquired assets related to environmental, title, regulatory, tax, contract, litigation or other matters of which we are unaware, which could materially and adversely affect our production, revenues and results of operations. We are sometimes able to obtain contractual indemnification for preclosing liabilities, including environmental liabilities, but we generally acquire interests in properties on an as is basis with limited remedies for breaches of representations and warranties. In addition, even when we are able to obtain such indemnification from the sellers, these indemnification obligations usually expire over time and expose us to potential unindemnified liabilities, which could materially adversely affect our production, revenues and results of operations.

Shortages of oilfield equipment, services and qualified personnel could delay our drilling program and increase the prices we pay to obtain such equipment, services and personnel.

The demand for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with oil and natural gas prices, causing periodic shortages. Historically, there have been shortages of drilling and workover rigs, pipe and other oilfield equipment as demand for rigs and equipment has increased along with the number of wells being drilled. These factors also cause significant increases in costs for equipment, services and personnel. Higher oil and natural gas prices generally stimulate demand and result in increased prices for drilling and workover rigs, crews and associated supplies, equipment and services. It is beyond our control and ability to predict whether these conditions will exist in the future and, if so, what their timing and duration will be. These types of shortages or price increases could significantly decrease our profit margin, cash flow and operating results, or restrict our ability to drill the wells and conduct the operations which we currently have planned and budgeted or which we may plan in the future.

Our estimates of proved reserves have been prepared under SEC rules which went into effect for fiscal years ending on or after December 31, 2009, which may make comparisons to prior to December 31, 2009 difficult and could limit our ability to book additional proved undeveloped reserves in the future.

This report presents estimates of our proved reserves as of December 31, 2011, which have been prepared and presented under the current SEC rules that are effective for fiscal years ending on or after December 31, 2009, and require SEC reporting companies to prepare their reserve estimates using revised reserve definitions and revised pricing based on a 12-month unweighted average of the first-day-of-the-month pricing. The previous rules required that reserve estimates be calculated using last-day-of-the-year pricing. The pricing that was used for estimates of our reserves as of December 31, 2011 was based on an unweighted average twelve month West Texas Intermediate posted price of $92.71 per Bbl for oil and a Henry Hub spot natural gas price of $4.12 per MMBtu for natural gas. As a result of this change in pricing methodology, direct comparisons of our reported reserve amounts under the rules prior to December 31, 2009 may be more difficult.

Another impact of the SEC rules is a general requirement that, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking. This rule has limited and may continue to limit our potential to book additional proved undeveloped reserves as we pursue our drilling program, particularly as we develop our significant acreage in West Texas and Southeast New Mexico. Moreover, we may be required to write down our proved undeveloped reserves if we do not drill on those reserves within the required five-year timeframe.

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Our exploration and development drilling may not result in commercially productive reserves.

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

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

We may not be able to obtain funding at all, or to obtain funding on acceptable terms, because of the deterioration of the credit and capital markets. This may hinder or prevent us from meeting our future capital needs and from refinancing our existing indebtedness.

In recent years, global financial markets and economic conditions experienced disruptions and volatility, which caused deterioration in the credit and capital markets. A recurrence of similar conditions in the future could make it difficult for us to obtain funding for our ongoing capital needs.

In volatile financial markets, the cost of raising money in the debt and equity capital markets can fluctuate widely and the availability of funds from those markets may diminish significantly. Due to these factors, we cannot be certain that funding will be available if needed and to the extent required, on acceptable terms. In addition, we may be unable to refinance our existing indebtedness as it comes due on terms that are acceptable to us or at all. If we cannot meet our capital needs or refinance our existing indebtedness, we may be unable to implement our development plan, enhance our existing business, complete acquisitions or otherwise take advantage of business opportunities or respond to competitive pressures, any of which could have a material adverse effect on our production, revenues and results of operations.

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We may incur substantial losses and be subject to substantial liability claims as a result of our oil and natural gas operations. In addition, we may not be insured for, or our insurance may be inadequate to protect us against, these risks.

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition or results of operations. Our oil and natural gas exploration and production activities, including well stimulation and completion activities such as hydraulic fracturing, are subject to all of the operating risks associated with drilling for and producing oil and natural gas, including the possibility of:

- environmental hazards, such as uncontrollable flows of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater contamination;
- abnormally pressured or structured formations;
- mechanical difficulties, such as stuck oilfield drilling and service tools and casing collapse;
- fires, explosions and ruptures of pipelines;
- personal injuries and death; and
- natural disasters.

Any of these risks could adversely affect our ability to conduct operations or result in substantial losses to us as a result of:

- injury or loss of life;
- damage to and destruction of property and equipment;
- damage to natural resources due to underground migration of hydraulic fracturing fluids;
- pollution and other environmental damage, including spillage or mishandling of recovered hydraulic fracturing fluids;
- regulatory investigations and penalties;
- suspension of our operations; and
- repair and remediation costs.

We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. The occurrence of an event that is not covered or not fully covered by insurance could have a material adverse effect on our production, revenues and results of operations.

Competition in the oil and natural gas industry is intense, making it more difficult for us to acquire properties, market oil and natural gas and secure trained personnel.

We operate in a highly competitive environment for acquiring properties, marketing oil and natural gas and securing trained personnel. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours, which can be particularly important in the areas in which we operate.

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Those companies may be able to pay more for productive oil and natural gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. In addition, those companies may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. The cost to attract and retain qualified personnel has increased over the past few years due to competition and may increase substantially in the future. Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital. Our failure to acquire properties, market oil and natural gas and secure trained personnel and adequately compensate personnel could have a material adverse effect on our production, revenues and results of operations.

Market conditions or operational impediments may hinder our access to oil and natural gas markets or delay our production.

Market conditions or the unavailability of satisfactory oil and natural gas processing or transportation arrangements may hinder our access to oil and natural gas markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas, the proximity of reserves to pipelines and terminal facilities, competition for such facilities and the inability of such facilities to gather, transport or process our production due to shutdowns or curtailments arising from mechanical, operational or weather related matters, including hurricanes and other severe weather conditions. Our ability to market our production depends in substantial part on the availability and capacity of gathering and transportation systems, pipelines and processing facilities owned and operated by third parties. Our failure to obtain such services on acceptable terms could have a material adverse effect on our business, financial condition and results of operations. We may be required to shut in or otherwise curtail production from wells due to lack of a market or inadequacy or unavailability of oil, natural gas liquids or natural gas pipeline or gathering, transportation or processing capacity. If that were to occur, then we would be unable to realize revenue from those wells until suitable arrangements were made to market our production.

Certain federal income tax deductions currently available with respect to oil and natural gas exploration and development may be eliminated as a result of future legislation.

President Obama s budget proposal for the fiscal year 2012 recommended the elimination of certain key United States federal income tax preferences currently available to oil and natural gas exploration and production companies. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs and (iii) the increase in the amortization period from two years to seven years for geophysical costs paid or incurred in connection with the exploration for, or development of, oil or natural gas within the United States.

It is unclear whether any such changes will actually be enacted or, if enacted, how soon any such changes could become effective. The passage of any legislation as a result of the budget proposal or any other similar change in United States federal income tax law could affect certain tax deductions that are currently available with respect to oil and natural gas exploration and production.

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

In December 2009, the EPA determined that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth s atmosphere and other climatic changes. Based on these findings, the EPA has begun adopting and implementing regulations to restrict emissions of greenhouse gases under existing provisions of the CAA. The EPA recently adopted two sets of rules regulating greenhouse gas emissions under the CAA, one of which requires a reduction in emissions of greenhouse gases from motor vehicles and the other of which regulates emissions of greenhouse gases from certain large stationary sources, effective January 2, 2011. The EPA s rules relating to emissions of greenhouse gases, including emissions, from large stationary sources are currently subject to a number of legal challenges, but the federal courts have thus far declined to issue any injunctions to prevent EPA from implementing, or requiring state environmental agencies to implement, the rules. The EPA has also adopted rules requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States, including petroleum refineries, on an annual basis, beginning in 2011 for emissions occurring after January 1, 2010, as well as certain onshore oil and natural gas production facilities, on an annual basis, beginning in 2012 for emissions occurring in 2011.

In addition, Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases and almost one-half of the states have already taken legal measures to reduce emissions of greenhouse gases primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall greenhouse gas emission reduction goal.

The adoption of legislation or regulatory programs to reduce emissions of greenhouse gases could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produced. Consequently, legislation and regulatory programs to reduce emissions of greenhouse gases could have an adverse effect on our business, financial condition and results of operations. Finally, it should be noted that some scientists have concluded that increasing concentrations of greenhouse gases in the earth s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations.

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

Congress recently adopted comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, including us, which participate in that market. The new legislation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Dodd-Frank Act), became law on July 21, 2010 and requires the Commodities Futures Trading Commission (the CFTC) and the SEC to promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment. In its rulemaking under the Dodd-Frank Act, the CFTC has proposed regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain *bona fide* hedging transactions or positions would be exempt from these position limits. It is not possible at this time to predict when the CFTC will finalize these regulations. The financial reform legislation may also require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our derivative activities, although the application of those provisions to us is uncertain at this time. The financial reform legislation may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty. The new legislation and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the legislation was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on us, our financial condition and our results of operations.

The loss of our chief executive officer or other key personnel could negatively impact our ability to execute our business strategy.

We depend, and will continue to depend in the foreseeable future, on the services of our chief executive officer, Timothy A. Leach, and other officers and key employees who have extensive experience and expertise in evaluating and analyzing producing oil and natural gas properties and drilling prospects, maximizing production from oil and natural gas properties, marketing oil and natural gas production, and developing and executing acquisition, financing and hedging strategies. Our ability to hire and retain our officers and key employees is important to our continued success and growth. The unexpected loss of the services of one or more of these individuals could negatively impact our ability to execute our business strategy.

Because we do not operate and therefore control the development of certain of the properties in which we own interests, we may not be able to produce economic quantities of oil and natural gas in a timely manner.

At December 31, 2011, approximately 8 percent of our proved reserves were attributable to properties for which we were not the operator. As a result, the success and timing of drilling and development activities on such nonoperated properties depend upon a number of factors, including:

- the nature and timing of drilling and operational activities;
- the timing and amount of capital expenditures;
- the operators expertise and financial resources;
- the approval of other participants in such properties; and
- the selection and application of suitable technology.

If drilling and development activities are not conducted on these properties or are not conducted on a timely basis, we may be unable to increase our production or offset normal production declines or we will be required to write-off the reserves attributable thereto, which may adversely affect our production, revenues and results of operations. Any such write-offs of our reserves could reduce our ability to borrow money and could reduce the value of our securities

Uncertainties associated with enhanced recovery methods may result in us not realizing an acceptable return on our investments in such projects.

We inject water into formations on some of our properties to increase the production of oil and natural gas. We may in the future expand these efforts to more of our properties or employ other enhanced recovery methods in our operations. The additional production and reserves, if any, attributable to the use of enhanced recovery methods are inherently difficult to predict. If our enhanced recovery methods do not allow for the extraction of oil and natural gas in a manner or to the extent that we anticipate, we may not realize an acceptable return on our investments in such projects. In addition, if proposed legislation and regulatory initiatives relating to hydraulic fracturing become law, the cost of some of these enhanced recovery methods could increase substantially.

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A terrorist attack or armed conflict could harm our business by decreasing our revenues and increasing our costs.

Terrorist activities, anti-terrorist efforts and other armed conflict involving the United States may adversely affect the United States and global economies and could prevent us from meeting our financial and other obligations. If any of these events occur or escalate, the resulting political instability and societal disruption could reduce overall demand for oil and natural gas, potentially putting downward pressure on demand for our production and causing a reduction in our revenue. Oil and natural gas related facilities could be direct targets of terrorist attacks, and our operations could be adversely impacted if significant infrastructure or facilities used for the production, transportation, processing or marketing of oil and natural gas production are destroyed or damaged. Costs for insurance and other security may increase as a result of these threats, and some insurance coverage may become more difficult to obtain, if available at all.

Risks Relating to Our Common Stock

Our restated certificate of incorporation, our bylaws and Delaware law contain provisions that could discourage acquisition bids or merger proposals, which may adversely affect the market price of our common stock.

Our restated certificate of incorporation authorizes our board of directors to issue preferred stock without stockholder approval. If our board of directors elects to issue preferred stock, it could be more difficult for a third party to acquire us. In addition, some provisions of our certificate of incorporation, our bylaws and Delaware law could make it more difficult for a third party to acquire control of us, even if the change of control would be beneficial to our stockholders, including:

- the organization of our board of directors as a classified board, which allows no more than approximately one-third of our directors to be elected each year;
- stockholders cannot remove directors from our board of directors except for cause and then only by the holders of not less than 66 2/3 percent of the voting power of all outstanding voting stock;
- the prohibition of stockholder action by written consent; and
- limitations on the ability of our stockholders to call special meetings and establish advance notice provisions for stockholder proposals and nominations for elections to the board of directors to be acted upon at meetings of stockholders.

Because we have no plans to pay dividends on our common stock, investors must look solely to stock appreciation for a return on their investment in us.

We do not anticipate paying any cash dividends on our common stock in the foreseeable future. We currently intend to retain all future earnings to fund the development and growth of our business. Any payment of future dividends will be at the discretion of our board of directors and will depend on, among other things, our earnings, financial condition, capital requirements, level of indebtedness, statutory and contractual restrictions applying to the payment of dividends and other considerations that our board of directors deems relevant. Covenants contained in our credit facility and the indentures governing our senior notes restrict the payment of dividends. Investors must rely on sales of their common stock after price appreciation, which may never occur, as the only way to realize a return on their investment. Investors seeking cash dividends should not purchase our common stock.

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The availability of shares for sale in the future could reduce the market price of our common stock.

In the future, we may issue securities to raise cash for acquisitions. We may also acquire interests in other companies by using a combination of cash and our common stock or just our common stock. We may also issue securities convertible into, or exchangeable for, or that represent the right to receive, our common stock. Any of these events may dilute your ownership interest in our company, reduce our earnings per share and have an adverse impact on the price of our common stock.

In addition, sales of a substantial amount of our common stock in the public market, or the perception that these sales may occur, could reduce the market price of our common stock. This could also impair our ability to raise additional capital through the sale of our securities.

Item 1B. Unresolved Staff Comments

There are no unresolved staff comments.

Item 2. Properties

Our Oil and Natural Gas Reserves

The estimates of our proved reserves at December 31, 2011, all of which were located in the United States, were based on evaluations prepared by the independent petroleum engineering firms of Cawley, Gillespie & Associates, Inc. (CGA) and Netherland, Sewell & Associates, Inc. (NSAI) (or collectively, our external engineers). Reserves were estimated in accordance with guidelines established by the SEC and the Financial Accounting Standards Board (the FASB).

Internal controls. Our proved reserves are estimated at the property level and compiled for reporting purposes by our corporate reservoir engineering staff, all of whom are independent of our operating teams. We maintain our internal evaluations of our reserves in a secure reserve engineering database. The corporate reservoir engineering staff interact with our internal staff of petroleum engineers and geoscience professionals in each of our operating areas and with accounting and marketing employees to obtain the necessary data for the reserves estimation process. Reserves are reviewed and approved internally by members of our senior management and the reserves committee.

Our internal professional staff works closely with our external engineers to ensure the integrity, accuracy and timeliness of data that is furnished to them for their reserve estimation process. All of the reserve information maintained in our secure reserve engineering database is provided to the external engineers. In addition, other pertinent data is provided such as seismic information, geologic maps, well logs, production tests, material balance calculations, well performance data, operating procedures and relevant economic criteria. We make available all information requested, including our pertinent personnel, to the external engineers as part of their evaluation of our reserves.

Qualifications of responsible technical persons.

E. Joseph Wright has been our Senior Vice President and Chief Operating Officer since November 2010. Mr. Wright previously served as the Vice President Engineering and Operations from our formation in February 2004 to October 2010. Previously, Mr. Wright served as Vice President Operations/Engineering of Concho Oil & Gas Corp. from its formation in January 2001 until its sale in January 2004, and as Vice President Operations for Concho Resources Inc. (which was a different company from the current company). He has also worked in several operations, engineering and capital markets positions at Mewbourne Oil Company. Mr. Wright is a graduate of Texas A&M University with a Bachelor of Science degree in Petroleum Engineering.

Gayle Burleson has been our Vice President Engineering, since September 2010. Ms. Burleson was our Manager of Corporate Engineering from July 2008 until September 2010. Ms. Burleson was Senior Reservoir Engineer for us from January 2006 until July 2008. From 1999 until 2006, Ms. Burleson was employed by BTA Oil Producers as a Senior Engineer responsible for Reservoir and Operations engineering duties in the Permian Basin, Oklahoma and North Dakota. From 1998 until 1999, Ms. Burleson was employed as a Staff Reservoir Engineer for Mobil Oil Corporation responsible for tertiary floods in Utah. From 1996 until 1998, Ms. Burleson was employed as a Senior Reservoir Engineer for Parker & Parsley Petroleum Company (now Pioneer Natural Resources Company) overseeing development in the Permian Basin, and she began her career in 1988 until 1996 with Exxon Corporation in various reservoir engineering capacities responsible for primary oil and natural gas fields, waterfloods and tertiary recovery floods in the Permian Basin and North Dakota. Ms. Burleson is a graduate of Texas Tech University with a Bachelor of Science degree in Chemical Engineering.

CGA. Approximately 67.3 percent of the proved reserves estimates shown herein at December 31, 2011 have been independently prepared by CGA, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. CGA was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-693. Within CGA, the technical person primarily responsible for preparing the estimates set forth in the CGA letter dated January 23, 2012, filed as an exhibit to this Annual Report on Form 10-K, was Mr. Zane Meekins. Mr. Meekins has been a practicing consulting petroleum engineer at CGA since 1989. Mr. Meekins is a Registered Professional Engineer in the State of Texas (License No. 71055) and has over 22 years of practical experience in petroleum engineering, with over 20 years of experience in the estimation and evaluation of reserves. He graduated from Texas A&M University in 1987 with a Bachelor of Science degree in Petroleum Engineering. Mr. Meekins meets or exceeds the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; he is proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserve definitions and guidelines.

NSAI. Approximately 32.7 percent of the proved reserve estimates shown herein at December 31, 2011 have been independently prepared by NSAI, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within NSAI, the technical person primarily responsible for preparing the estimates set forth in the NSAI letter dated January 26, 2012, filed as an exhibit to this Annual Report on Form 10-K, was Mr. G. Lance Binder. Mr. Binder has been a practicing consulting petroleum engineer at NSAI since 1983. Mr. Binder is a Registered Professional Engineer in the State of Texas (License No. 61794) and has over 30 years of practical experience in petroleum engineering, with over 29 years of experience in the estimation and evaluation of reserves. He graduated from Purdue University in 1978 with a Bachelor of Science degree in Chemical Engineering. Mr. Binder meets or exceeds the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; he is proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserve definitions and guidelines.

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Our oil and natural gas reserves. The following table sets forth our estimated proved oil and natural gas reserves, PV-10 and Standardized Measure at December 31, 2011. PV-10 and Standardized Measure include the present value of our estimated future abandonment and site restoration costs for proved properties net of the present value of estimated salvage proceeds from each of these properties. Our reserve estimates and our computation of future net cash flows are based on a 12-month unweighted average of the first-day-of-the-month pricing of $92.71 per Bbl West Texas Intermediate posted oil price and on a 12-month unweighted average of the first-day-of-the-month pricing of $4.12 per MMBtu Henry Hub spot natural gas price, adjusted for location and quality by property.

	Oil (MBbl)	Natural Gas (MMcf)	Total (MBoe)	PV-10 [(a)] (in millions)
Core Operating Areas:				
New Mexico Shelf	135,726	447,254	210,268	$ 5,083.3
Delaware Basin	18,799	185,698	49,749	904.9
Texas Permian	83,770	256,329	126,492	2,411.4
Other	1	68	12	0.2
Total	238,296	889,349	386,521	8,399.8
Present value of future income taxes discounted at 10%				(2,698.7)
Standardized Measure				$ 5,701.1

The following table sets forth our estimated proved reserves by category at December 31, 2011:

	Oil (MBbl)	Natural Gas (MMcf)	Total (MBoe)	Percent of Total	PV-10 [(a)] (in millions)
Proved developed producing	130,261	515,645	216,202	55.9%	$ 5,748.1
Proved developed non-producing	13,651	36,455	19,727	5.1%	448.1
Proved undeveloped	94,384	337,249	150,592	39.0%	2,203.6
Total proved	238,296	889,349	386,521	100.0%	$ 8,399.8

Total proved developed	143,912	552,100	235,929	61.0%	$ 6,196.2

(a) Our Standardized Measure at December 31, 2011 was $5.7 billion. PV-10 is a Non-GAAP financial measure and is derived from the Standardized Measure which is the most directly comparable GAAP financial measure. PV-10 is a computation of the Standardized Measure on a pre-tax basis. PV-10 is equal to the Standardized Measure at the applicable date, before deducting future income taxes, discounted at 10 percent. We believe that the presentation of PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to our estimated proved reserves prior to taking into account future corporate income taxes, and it is a useful measure for evaluating the relative monetary significance of our oil and natural gas assets. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies. We use this measure when assessing the potential return on investment related to our oil and natural gas assets. PV-10, however, is not a substitute for the Standardized Measure. Our PV-10 measure and the Standardized Measure do not purport to present the fair value of our oil and natural gas reserves. See Item 1. Business Non-GAAP Financial Measures and Reconciliations.

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Changes to proved reserves. The following table sets forth the changes in our proved reserve volumes by area during the year ended December 31, 2011 (in MBoe):

	Production	Extensions and Discoveries	Purchases of Minerals-in-Place	Sales of Minerals-in-Place	Revisions of Previous Estimates
Core Operating Areas:					
New Mexico Shelf	(13,017)	34,856	726	-	(5,233)
Delaware Basin	(4,590)	26,124	5,716	-	406
Texas Permian	(5,908)	25,086	6,137	-	679
Other	(129)	422	-	(8,357)	151
Total	(23,644)	86,488	12,579	(8,357)	(3,997)

Production. Production volumes of 23.6 MMBoe include production of 123 MBoe for the Bakken assets divested in March 2011.

Extensions and discoveries. Extensions and discoveries are primarily the result of our continued success from our extension and infill drilling in the Yeso of Southeast New Mexico and the Wolfberry in West Texas and our exploratory drilling success in the Delaware Basin.

Purchases of minerals-in-place. Purchases of minerals-in-place are primarily attributable to a Wolfberry acquisition, which closed in the first quarter of 2011, and the OGX Acquisition, which closed in the fourth quarter of 2011.

Sales of minerals-in-place. In March 2011, we sold our Bakken assets.

Revisions of previous estimates. Revisions of previous estimates are comprised of 6.0 MMBoe of positive revisions resulting from an increase in oil price and 10.0 MMBoe of negative revisions primarily resulting from technical and performance evaluations. The Company s proved reserves at December 31, 2011 were determined using the twelve month average equivalent prices of $92.71 per Bbl of oil for West Texas Intermediate and $4.12 per MMBtu of natural gas for Henry Hub spot, compared to corresponding prices of $75.96 per Bbl of oil and $4.38 per MMBtu of natural gas at December 31, 2010.

Proved undeveloped reserves. At December 31, 2011, we had approximately 150.6 MMBoe of proved undeveloped reserves as compared to 138.9 MMBoe at December 31, 2010.

The following table summarizes the changes in our proved undeveloped reserves during 2011 (in MBoe):

At December 31, 2010	138,931

Extensions and discoveries	55,026
Purchases of minerals-in-place	9,448
Sales of minerals-in-place	(5,665)
Revisions of previous estimates	(10,532)
Conversion to proved developed reserves	(36,616)
At December 31, 2011	150,592

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Our purchases of minerals-in-place are primarily attributable to a Wolfberry acquisition, which closed in the first quarter of 2011, and the OGX Acquisition, which closed in the fourth quarter of 2011. Our extensions and discoveries are primarily the result of our continued success from our extension and infill drilling in the Yeso of Southeast New Mexico and the Wolfberry in West Texas and our exploratory drilling success in the Delaware Basin.

The following table sets forth, since 2008, proved undeveloped reserves converted to proved developed reserves during the respective year and the investment required to convert proved undeveloped reserves to proved developed reserves:

Years Ended December 31,	**Proved Undeveloped Reserves Converted to Proved Developed Reserves**			**Investment in Conversion of Proved Undeveloped Reserves to Proved Developed Reserves**
	Oil (MBbls)	**Natural Gas (MMcf)**	**Total (MBoe)**	**(in thousands)**
2008 [(a)]	4,378	15,681	6,992	$ 114,067
2009	7,453	19,860	10,763	131,773
2010	20,117	52,318	28,836	309,439
2011	25,201	68,495	36,616	491,602
Total	57,149	156,354	83,207	$ 1,046,881

(a) Our initial disclosures of our reserves occurred in our initial public offering in August 2007.

The following table sets forth the estimated timing and cash flows of developing our proved undeveloped reserves at December 31, 2011 (dollars in thousands):

Years Ended December 31, [(a)]	**Future Production (MBoe)**	**Future Cash Inflows**	**Future Production Costs**	**Future Development Costs**	**Future Net Cash Flows**
2012	3,456	$ 269,480	$ 28,985	$ 548,792	$ (308,297)

2013	8,167	605,692	69,143	521,016	15,533
2014	10,550	788,219	95,105	575,620	117,494
2015	12,432	925,380	117,970	450,410	357,000
2016	11,747	872,600	120,070	224,395	528,135
Thereafter	104,240	7,811,304	2,295,891	46,203	5,469,210
Total	150,592	$ 11,272,675	$ 2,727,164	$ 2,366,436	$ 6,179,075

(a) Beginning in 2013 and thereafter, the production and cash flows represent the drilling results from the respective year plus the incremental effects from the results of proved undeveloped drilling from the preceding years.

Historically, our drilling programs were substantially funded from our cash flow and were weighted towards drilling unproven locations. Our expectation in the future is to continue to fund our drilling programs primarily from our cash flows. Based on our current expectations over the next 5 years of our cash flows and drilling programs, which includes drilling of proved undeveloped and unproven locations, we believe that we can continue to substantially fund our drilling activities from our cash flow and, if needed, with borrowings from our credit facility.

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Developed and Undeveloped Acreage

The following table presents our total gross and net developed and undeveloped acreage by area at December 31, 2011:

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Core Operating Areas:						
New Mexico Shelf	86,285	44,935	154,119	79,343	240,404	124,278
Delaware Basin	159,462	76,502	251,415	196,723	410,877	273,225
Texas Permian	165,909	42,085	113,518	68,621	279,427	110,706
Other	-	-	38,318	25,300	38,318	25,300
Total	411,656	163,522	557,370	369,987	969,026	533,509

The following table sets forth the future expiration amounts of our gross and net undeveloped acreage at December 31, 2011 by area. Expirations may be less if production is established or continuous development activities are undertaken beyond the primary term of the lease.

	2012		2013		2014		Thereafter	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Core Operating Areas:								
New Mexico Shelf	25,685	9,481	17,056	9,211	25,073	22,844	1,198	1,198
Delaware Basin	7,625	3,801	38,558	21,677	3,741	1,992	117,248	105,559
Texas Permian	2,112	1,055	1,250	967	-	-	64,599	42,273
Other	-	-	1,920	1,440	9,991	7,494	26,407	16,366
Total	35,422	14,337	58,784	33,295	38,805	32,330	209,452	165,396

Title to Our Properties

As is customary in the oil and natural gas industry, we initially conduct only a cursory review of the title to our properties on which we do not have proved reserves. Prior to the commencement of drilling operations on those properties, we conduct a more thorough title examination and perform curative work with respect to significant defects. To the extent title opinions or other investigations reflect defects affecting those properties, we are typically responsible for curing any such defects at our expense. We generally will not commence drilling operations on a property until we have cured known material title defects on such property. We have reviewed the title to substantially all of our producing properties and believe that we have satisfactory title to our producing properties in accordance with standards generally accepted in the oil and natural gas industry. Prior to completing an acquisition of producing oil and natural gas properties, we perform title reviews on the most significant properties and, depending on the materiality of properties, we may obtain a title opinion or review or update previously obtained title opinions. Our oil and natural gas properties are subject to customary royalty and other interests, liens to secure borrowings under our credit facility, liens for current taxes and other burdens which we believe do not materially interfere with the use or affect our carrying value of the properties.

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Item 3. Legal Proceedings

We are a party to proceedings and claims incidental to our business. While many of these other matters involve inherent uncertainty, we believe that the liability, if any, ultimately incurred with respect to such other proceedings and claims will not have a material adverse effect on our consolidated financial position as a whole or on our liquidity, capital resources or future results of operations. We will continue to evaluate proceedings and claims involving us on a quarter-by-quarter basis and will establish and adjust any reserves as appropriate to reflect our assessment of the then current status of the matters.

Item 4. Mine Safety Disclosures

Not applicable.

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PART II

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

Market Information

Our common stock trades on the NYSE under the symbol CXO. The following table shows, for the periods indicated, the high and low sales prices for our common stock, as reported on the NYSE.

	Price Per Share	
	High	**Low**
2010:		
First Quarter	$ 51.62	$ 42.60
Second Quarter	$ 61.65	$ 44.30
Third Quarter	$ 66.49	$ 51.51
Fourth Quarter	$ 89.87	$ 65.95
2011:		
First Quarter	$ 110.89	$ 84.13
Second Quarter	$ 109.95	$ 83.51
Third Quarter	$ 99.47	$ 71.05
Fourth Quarter	$ 105.66	$ 63.20

On February 21, 2012 the last sales price of our common stock as reported on the New York Stock Exchange was $115.84 per share.

As of February 21, 2012, there were 570 holders of record of our common stock.

Dividend Policy

We have not paid, and do not intend to pay in the foreseeable future, cash dividends on our common stock. Covenants contained in our credit facility and the indentures governing our senior notes restrict the payment of dividends on our common stock. We currently intend to retain all future earnings to fund the development and growth of our business. Any payment of future dividends will be at the discretion of our board of directors and will depend on, among other things, our earnings, financial condition, capital requirements, level of indebtedness, statutory and contractual restrictions applying to the payment of dividends and other considerations that our board of directors deems relevant.

Repurchase of Equity Securities

Period	Total number of shares withheld [a]	Average price per share	Total number of shares purchased as part of publicly announced plans	Maximum number of shares that may yet be purchased under the plan
October 1, 2011 - October 31, 2011	-	$ -	-	
November 1, 2011 - November 30, 2011	2,792	$ 98.25	-	
December 1, 2011 - December 31, 2011	1,699	$ 94.48	-	

(a) Represents shares that were withheld by us to satisfy tax withholding obligations of certain of our officers and key employees that arose upon the lapse of restrictions on restricted stock.

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Item 6. Selected Financial Data

This section presents our selected historical consolidated financial data. The selected historical consolidated financial data presented below is not intended to replace our historical consolidated financial statements. You should read the following data along with Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations and the consolidated financial statements and related notes, each of which is included in this report.

Selected Historical Financial Information

Our results of operations for the periods presented below may not be comparable either from period to period or going forward for the following reasons:

- in August 2007, we completed our initial public offering of common stock from which we received proceeds of $173 million that we used to retire outstanding borrowings under our second lien term loan facility totaling $86.5 million, and to retire outstanding borrowings under our credit facility totaling $86.5 million;

- in July 2008, we closed our acquisition of Henry Petroleum LP and certain entities affiliated with Henry Petroleum LP (which we refer to collectively as the Henry Entities), together with certain additional non-operated interests in oil and natural gas properties from persons affiliated with the Henry Entities. In August 2008 and September 2008, we acquired additional non-operated interests in oil and natural gas properties from persons affiliated with the Henry Entities (known as along-side interests). The assets acquired in the acquisition of the Henry Entities and the along-side interests (which we refer to as the Henry Properties) contained approximately 30.1 MMBoe of proved reserves at closing. We paid approximately $583.7 million in net cash for the Henry Properties, which was funded with borrowings under our credit facility and net proceeds of approximately $242.4 million from our private placement of 8.3 million shares of our common stock. The results of operations prior to August 2008 do not include results from the Henry Properties acquisition;

- in September 2009, we issued $300 million of 8.625% senior notes at a discount, resulting in a yield-to-maturity of 8.875 percent. The net proceeds from this offering was used to repay a portion of the borrowings under our credit facility;

- in December 2009, together with the acquisition of related additional interests that closed in 2010, we closed the Wolfberry Acquisitions for approximately $270.7 million in cash. The results of operations prior to 2010 do not include results from the Wolfberry Acquisitions;

- in February 2010, we issued approximately 5.3 million shares of our common stock at $42.75 per share in a secondary public offering resulting in net proceeds of approximately $219.3 million. The net proceeds from this offering were used to repay a portion of the borrowings under our credit facility;

- in October 2010, we closed the Marbob and Settlement Acquisitions for aggregate consideration of approximately $1.6 billion. The Marbob Acquisition consideration was comprised of (i) approximately $1.1 billion in cash which was funded with borrowings under our credit facility and with net proceeds of a $292.7 million private placement of 6.6 million shares of our common stock, (ii) issuance of 1.1 million shares of our common stock to the sellers and (iii) issuance of a $150 million 8.0% senior note due 2018 to the sellers, which was repaid in May of 2011 with borrowings under our credit facility. The Settlement Acquisition cash consideration of $286 million was primarily funded with borrowings under our credit facility. The results of operations prior to October 2010 do not include results from the Marbob and Settlement Acquisitions;

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in December 2010, we issued in a secondary public offering 2.9 million shares of our common stock at $82.50 per share and we received net proceeds of approximately $227.4 million. We used the net proceeds from this offering to repay a portion of the borrowings under our credit facility;

in December 2010, we issued $600 million in principal amount of 7.0% senior notes due 2021 at par and we received net proceeds of approximately $587.4 million. We used the net proceeds from this offering to repay a portion of the borrowings under our credit facility;

in December 2010, we sold certain of our non-core Permian Basin assets for cash consideration of approximately $103.3 million and recognized a pre-tax gain on the disposition of assets (included in discontinued operations) of approximately $29.1 million. For 2010, these assets produced an average of 1,393 Boe per day, of which approximately 46 percent was oil;

in March 2011, we sold our Bakken assets for cash consideration of approximately $195.9 million and recognized a pre-tax gain on the disposition of assets (included in discontinued operations) of approximately $135.9 million. For the first quarter of 2011, these assets produced an average of 1,369 Boe per day;

in May 2011, we issued $600 million in principal amount of 6.5% senior notes due 2022 at par and we received net proceeds of approximately $587.1 million. We used the net proceeds to repay a portion of the borrowings under our credit facility, which increased our liquidity for future activities; and

in November 2011, we closed the OGX Acquisition for cash consideration of approximately $252.4 million, subject to customary post-closing adjustments. The results of operations prior to December 2011 do not include results from the OGX Acquisition.

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Our financial data below is derived from (i) our audited consolidated financial statements included in this report and (ii) other audited consolidated financial statements of ours not included in this report after taking into account the necessary reclassifications to present discontinued operations.

	Years Ended December 31,				
(in thousands, except per share amounts)	2011	2010 (a)	2009 (b)	2008 (c)	2007
Statement of operations data:					
Total operating revenues	$ 1,739,967	$ 940,267	$ 510,767	$ 492,347	$ 267,029
Total operating costs and expenses	(871,182)	(583,941)	(517,962)	(35,271)	(199,521)
Income (loss) from operations	$ 868,785	$ 356,326	$ (7,195)	$ 457,076	$ 67,508
Income (loss) from continuing operations, net of tax	$ 460,603	$ 170,648	$ (13,312)	$ 271,344	$ 20,151
Income from discontinued operations, net of tax	$ 87,534	$ 33,722	$ 3,510	$ 7,358	$ 5,209
Net income (loss) attributable to common shareholders	$ 548,137	$ 204,370	$ (9,802)	$ 278,702	$ 25,315
Basic earnings per share:					
Income (loss) from continuing operations	$ 4.49	$ 1.84	$ (0.16)	$ 3.43	$ 0.31
Income from discontinued operations, net of tax	0.85	0.37	0.04	0.09	0.08
Net income (loss) attributable to common shareholders	$ 5.34	$ 2.21	$ (0.12)	$ 3.52	$ 0.39
Diluted earnings per share:					
Income (loss) from continuing operations	$ 4.44	$ 1.82	$ (0.16)	$ 3.37	$ 0.30
Income from discontinued operations, net of tax	0.84	0.36	0.04	0.09	0.08
Net income (loss) attributable to common shareholders	$ 5.28	$ 2.18	$ (0.12)	$ 3.46	$ 0.38
Other financial data:					
Net cash provided by operations	$ 1,199,458	$ 651,582	$ 359,546	$ 391,397	$ 169,769
Net cash used in investing activities	$ 1,651,418	$ 2,043,457	$ 586,148	$ 946,050	$ 160,353
Net cash provided by financing activities	$ 451,918	$ 1,389,025	$ 212,084	$ 541,981	$ 19,886
EBITDAX (d)	$ 1,275,159	$ 742,994	$ 475,208	$ 401,303	$ 217,392

	December 31,				
(in thousands)	2011	2010 (a)	2009 (b)	2008 (c)	2007
Balance sheet data:					
Cash and cash equivalents	$ 342	$ 384	$ 3,234	$ 17,752	$ 30,424
Property and equipment, net	6,290,118	4,913,787	2,856,289	2,401,404	1,394,994
Total assets	6,849,576	5,368,494	3,171,085	2,815,203	1,508,229
Long-term debt, including current maturities	2,080,141	1,668,521	845,836	630,000	327,404
Stockholders' equity	2,980,739	2,383,874	1,335,428	1,325,154	775,398

(a) The Marbob and Settlement Acquisitions closed in October 2010. See Note D of the Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data.

(b) The Wolfberry Acquisitions closed in December 2009. See Note D of the Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data.

(c) The Henry Entities acquisition closed in July 2008.

(d) EBITDAX is defined as net income (loss), plus (1) exploration and abandonments expense, (2) depreciation, depletion and amortization expense, (3) accretion expense, (4) impairments of long-lived assets, (5) non-cash stock-based compensation expense, (6) bad debt expense, (7) ineffective portion of cash flow hedges, (8) unrealized (gain) loss on derivatives not designated as hedges, (9) (gain) loss on sale of assets, net, (10) interest expense, (11) federal and state income taxes on continuing operations and (12) similar items listed above that are presented in discontinued operations. See Item 1. Business Non-GAAP Financial Measures and Reconciliations.

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

The following discussion is intended to assist you in understanding our business and results of operations together with our present financial condition. This section should be read in conjunction with our historical consolidated financial statements and notes, as well as the selected historical consolidated financial data included elsewhere in this report. As a result of the acquisitions and divestures discussed below, many comparisons between periods will be difficult or impossible.

In November 2011, we closed on the OGX Acquisition. The results of operations prior to December 2011 do not include results from the OGX Acquisition.

In March 2011, we closed our divestiture of our Bakken assets for cash consideration of approximately $195.9 million and recognized a pre-tax gain on this sale of approximately $135.9 million (included in discontinued operations). For the first quarter of 2011, these assets produced an average of 1,369 Boe per day.

In December 2010, we sold certain of our non-core Permian Basin assets for cash consideration of approximately $103.3 million and recognized a pre-tax gain on this sale of approximately $29.1 million (included in discontinued operations). For 2010, these assets produced 1,393 Boe per day.

In October 2010, we closed the Marbob and Settlement Acquisitions. The results of these acquisitions are included in our results of operations for periods after their respective closing dates in October 2010.

In December 2009, we closed the Wolfberry Acquisitions. The results of these acquisitions are included in our results of operations beginning January 1, 2010.

Certain statements in our discussion below are forward-looking statements. These forward-looking statements involve risks and uncertainties. We caution that a number of factors could cause actual results to differ materially from these implied or expressed by the forward-looking statements. Please see Cautionary Statement Regarding Forward-Looking Statements.

Overview

We are an independent oil and natural gas company engaged in the acquisition, development and exploration of producing oil and natural gas properties. Our core operations are primarily focused in the Permian Basin of Southeast New Mexico and West Texas. We refer to our three core operating areas as the (i) New Mexico Shelf, where we primarily target the Yeso and Lower Abo formations, (ii) Delaware Basin, where we primarily target the Bone Spring formation (which includes the Avalon Shale and the Bone Springs sands) and the Wolfcamp shale, and (iii) Texas Permian, where we primarily target the Wolfberry, a term applied to the combined Wolfcamp and Spraberry horizons. Oil comprised 61.7 percent of our 386.5 MMBoe of estimated proved reserves at December 31, 2011 and 62.1 percent of our 23.6 MMBoe of production for 2011. We seek to operate the wells in which we own an interest, and we operated wells that accounted for 93.0 percent of our proved developed producing PV-10 and 78.8 percent of our 5,504 gross wells at December 31, 2011. By controlling operations, we are able to more effectively manage the cost and timing of exploration and development of our properties, including the drilling and stimulation methods used.

Financial and Operating Performance

Our financial and operating performance for 2011 included the following highlights:

Net income was $548.1 million ($5.28 per diluted share), as compared to net income of $204.4 million ($2.18 per diluted share) in 2010. The increase in earnings is primarily due to:

- $799.7 million increase in oil and natural gas revenues as a result of increased commodity price realizations and a 61 percent increase in production;
- $64.0 million decrease in net losses on derivatives not designated as hedges;
- $135.9 million pre-tax gain from the divestiture of our Bakken assets, included in discontinued operations;

offset by;

- $186.7 million increase in depreciation, depletion and amortization (DD&A) expense, primarily due to increased production in 2011;
- $141.6 million increase in oil and natural gas production costs due in part to increased (i) production in 2011, (ii) labor costs, (iii) routine environmental related costs and (iv) oil and natural gas revenues in 2011 that directly increased our oil and natural gas production taxes; and
- $58.3 million increase in interest expense due to (i) the October 2010 borrowings related to the Marbob and Settlement Acquisitions and the issuance of the 8.0% Marbob note, which was repaid in May 2011, (ii) the December 2010 $600 million issuance of 7.0% senior notes due 2021, (iii) the May 2011 $600 million issuance of 6.5% senior notes due 2022 and (iv) the amortization of capitalized loan costs associated with senior notes and the Marbob note premium.

Average daily sales volumes from continuing operations increased during 2011 by 61 percent from 39,915 Boe per day during 2010 to 64,442 Boe per day during 2011. The increase is primarily attributable to (i) our successful drilling efforts during 2010 and 2011 and (ii) 2011 having a full year effect from the Marbob and Settlement Acquisitions.

Net cash provided by operating activities increased by approximately $547.9 million to $1,199.5 million for 2011, as compared to $651.6 million in 2010, primarily due to the increased oil and natural gas revenues, offset by increases in related oil and natural gas production costs and other cash related costs.

Long-term debt was increased by approximately $411.6 million during 2011, primarily as a result of acquisitions in 2011.

At December 31, 2011 our availability under our credit facility was approximately $1.4 billion.

Commodity Prices

Our results of operations are heavily influenced by commodity prices. Factors that may impact future commodity prices, including the price of oil and natural gas, include:

- developments generally impacting the Middle East, including Iraq and Iran;
- the extent to which members of the Organization of Petroleum Exporting Countries and other oil exporting nations are able to continue to manage oil supply through export quotas;

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- the overall global demand for oil; and
- overall North American natural gas supply and demand fundamentals, including:
  - the United States economy impact,
  - weather conditions, and
  - liquefied natural gas deliveries to the United States.

Although we cannot predict the occurrence of events that may affect future commodity prices or the degree to which these prices will be affected, the prices for any commodity that we produce will generally approximate current market prices in the geographic region of the production. From time to time, we expect that we may economically hedge a portion of our commodity price risk to mitigate the impact of price volatility on our business. See Note I of the Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data for additional information regarding our commodity derivative positions at December 31, 2011.

Oil and natural gas prices have been subject to significant fluctuations during the past several years. In general, oil prices were higher during 2011 measured against 2010, while natural gas prices were lower. The following table sets forth the average NYMEX oil and natural gas prices for the years ended December 31, 2011, 2010 and 2009, as well as the high and low NYMEX price for the same periods:

	Years Ended December 31,		
	2011	2010	2009
Average NYMEX prices:			
Oil (Bbl)	$ 95.07	$ 79.50	$ 61.95
Natural gas (MMBtu)	$ 4.03	$ 4.40	$ 4.16
High and low NYMEX prices:			
Oil (Bbl):			
High	$ 113.93	$ 91.51	$ 81.37
Low	$ 75.67	$ 68.01	$ 33.98
Natural gas (MMBtu):			
High	$ 4.85	$ 6.01	$ 6.07
Low	$ 2.99	$ 3.29	$ 2.51

Further, the NYMEX oil price and NYMEX natural gas price reached highs and lows of $105.84 and $96.36 per Bbl and $3.10 and $2.32 per MMBtu, respectively, during the period from January 1, 2012 to February 21, 2012. At February 21, 2012, the NYMEX oil price and NYMEX natural gas price were $105.84 per Bbl and $2.63 per MMBtu, respectively.

Recent Events

PDC Acquisition. In December 2011, we entered into a definitive agreement for the PDC Acquisition for approximately $175 million, subject to customary purchase price adjustments. We estimated that the PDC Acquisition had approximately 12.5 MMBoe of proved reserves at November 1, 2011. Subject to closing conditions, we expect to close the PDC Acquisition in the first quarter of 2012 and fund it with borrowings under our credit facility.

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Delaware Basin Acquisitions

OGX Acquisition. In November 2011, we closed the OGX Acquisition for cash consideration of approximately $252.4 million, subject to customary post-closing adjustments. The OGX Acquisition consisted of producing and non-producing acreage in the Delaware Basin of Southeast New Mexico and West Texas. The OGX Acquisition contained approximately 5.7 MMBoe of proved reserves at closing. The OGX Acquisition was primarily funded with borrowings under our credit facility. The results of operations prior to December 2011 do not include results from the OGX Acquisition.

Other Delaware Basin Acquisitions. In the third and fourth quarters of 2011, in four acquisitions, we acquired approximately $79 million of non-producing acreage in the Delaware Basin. These acquisitions were primarily funded with borrowings under our credit facility.

Credit facility amendment. In 2011, we amended our credit facility to (i) extend the maturity date by approximately three years to April 2016, (ii) increase the borrowing base from $2.0 billion to $2.5 billion, but keep our commitments from our bank group at $2.0 billion and (iii) provide us with the ability to issue up to an additional $1.0 billion in senior notes with no adjustment to our borrowing base if the notes are issued prior to November 2012. We paid our bank group approximately $11.5 million associated with these amendments. At December 31, 2011, we had borrowings outstanding under our credit facility of approximately $0.6 billion, and our availability under our credit facility was approximately $1.4 billion.

Senior notes issuance. In May 2011, we issued $600 million in principal amount of 6.5% senior notes due 2022 at par and we received net proceeds of approximately $587.1 million. We used the net proceeds to repay a portion of the borrowings under our credit facility, which increased our liquidity for future activities.

Bakken asset divestiture. In March 2011, we closed our divestiture of our Bakken assets for cash consideration of approximately $195.9 million and recognized a pre-tax gain on this sale of approximately $135.9 million (included in discontinued operations). For the first quarter of 2011, these assets produced an average of 1,369 Boe per day. The proved reserves of the Bakken assets at closing were approximately 8.4 MMBoe.

***2012 capital budget*.** In November 2011, we announced our 2012 capital budget of approximately $1.3 billion, which was subsequently revised to $1.37 billion in connection with the PDC Acquisition (exclusive of the $175 million PDC Acquisition purchase price), which we expect can be funded substantially within our cash flow, based on current commodity prices and our expectations of costs. We take a longer-term view on spending substantially within our cash flow, and our spending during any specific period may exceed our cash flow for that period. However, our capital budget is largely discretionary, and if we experience sustained oil and natural gas prices significantly below the current levels or substantial increases in our drilling and completion costs, we may reduce our capital spending program to be substantially within our cash flow.

Our capital budget does not include acquisitions (other than the customary purchase of leasehold acreage). The following is a summary of our 2012 capital budget:

(in millions)	**2012 Capital Budget**
Drilling and completion costs:	
New Mexico Shelf	$ 496
Delaware Basin	420
Texas Permian	336
Acquisition of leasehold acreage and other property interests, geological and geophysical and other	58
Facilities and other capital in our core operating areas	55
Total	$ 1,365

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Derivative Financial Instruments

Derivative financial instrument exposure. At December 31, 2011, the fair value of our financial derivatives was a net liability of $78.8 million. All of our counterparties to these financial derivatives are parties to our credit facility and have their outstanding debt commitments and derivative exposures collateralized pursuant to our credit facility. Under the terms of our financial derivative instruments and their collateralization under our credit facility, we do not have exposure to potential margin calls on our financial derivative instruments. We currently have no reason to believe that our counterparties to these commodity derivative contracts are not financially viable. Our credit facility does not allow us to offset amounts we may owe a lender against amounts we may be owed related to our financial instruments with such party.

New commodity derivative contracts. During 2011 we entered into additional commodity derivative contracts to hedge a portion of our estimated future production. The following table summarizes information about these additional commodity derivative contracts for the year ended December 31, 2011. When aggregating multiple contracts, the weighted average contract price is disclosed.

	Aggregate Volume	Index Price [(a)]	Contract Period
Oil (volumes in Bbls):			
Price swap	115,000	$96.65	03/01/11 - 11/30/11
Price swap	200,000	$97.20	03/01/11 - 12/31/11
Price swap	190,000	$111.41	05/01/11 - 07/31/11
Price swap	736,000	$110.21	05/01/11 - 12/31/11
Price swap	66,000	$111.80	08/01/11 - 11/30/11
Price swap	535,000	$100.66	10/01/11 - 12/31/11
Price swap	45,000	$99.35	01/01/12 - 03/31/12
Price swap	176,000	$110.28	01/01/12 - 11/30/12
Price swap	3,324,000	$99.07	01/01/12 - 12/31/12
Price swap	177,000	$98.60	03/01/12 - 12/31/12
Price swap	327,000	$98.18	07/01/12 - 09/30/12
Price swap	255,000	$99.00	10/01/12 - 12/31/12
Price swap	210,000	$103.65	01/01/13 - 06/30/13
Price swap	6,002,000	$96.66	01/01/13 - 12/31/13
Price swap	109,000	$91.60	01/01/14 - 12/31/14
Price swap	92,000	$90.05	01/01/15 - 12/31/15
Price swap	81,000	$89.65	01/01/16 - 12/31/16

(a) The index prices for the oil price swaps are based on the NYMEX-West Texas Intermediate monthly average futures price.

Post-2011 commodity derivative contracts. After December 31, 2011, we entered into the following oil price commodity derivative contracts to hedge an additional portion of our estimated future production:

	Aggregate Volume	Index Price [a]	Contract Period
Oil (volumes in Bbls):			
Price swap	712,000	$ 98.90	02/01/12 - 08/31/12
Price swap	150,000	$ 98.90	02/01/12 - 11/30/12
Price swap	990,000	$ 99.75	02/01/12 - 12/31/12
Price swap	183,000	$ 98.65	01/01/13 - 03/31/13
Price swap	130,000	$ 97.65	01/01/13 - 10/31/13
Price swap	110,000	$ 97.40	01/01/13 - 11/30/13
Price swap	2,040,000	$ 97.62	01/01/13 - 12/31/13
Price swap	1,350,000	$ 95.45	01/01/14 - 03/31/14

(a) The index price for the oil price swap is based on the NYMEX-West Texas Intermediate monthly average futures price.

Results of Operations

The following table sets forth summary information concerning our production and operating data from continuing operations for the years ended December 31, 2011, 2010 and 2009. The table below excludes production and operating data that we have classified as discontinued operations, which is more fully described in Note O of the Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data. The actual historical data in this table excludes results from the (i) OGX Acquisition for periods prior to December 2011, (ii) Marbob and Settlement Acquisitions for periods prior to their respective close dates in October 2010 and (iii) Wolfberry Acquisitions for periods prior to 2010. Because of normal production declines, increased or decreased drilling activities and the effects of acquisitions or divestitures, the historical information presented below should not be interpreted as being indicative of future results.

	Years Ended December 31,		
	2011	2010	2009
Production and operating data:			
Net production volumes:			
Oil (MBbl)	14,575	9,621	6,874
Natural gas (MMcf)	53,677	29,687	19,692
Total (Boe)	23,521	14,569	10,156
Average daily production volumes:			
Oil (Bbl)	39,932	26,359	18,833
Natural gas (Mcf)	147,060	81,334	53,951
Total (Boe)	64,442	39,915	27,825
Average prices:			
Oil, without derivatives (Bbl)	$ 91.29	$ 76.43	$ 58.12
Oil, with derivatives (Bbl) (a)	$ 84.16	$ 73.70	$ 69.00
Natural gas, without derivatives (Mcf)	$ 7.63	$ 6.90	$ 5.65
Natural gas, with derivatives (Mcf) (a)	$ 8.11	$ 7.49	$ 6.21
Total, without derivatives (Boe)	$ 73.98	$ 64.54	$ 50.29
Total, with derivatives (Boe) (a)	$ 70.65	$ 63.93	$ 58.74
Operating costs and expense per Boe:			
Lease operating expenses and workover costs	$ 7.08	$ 5.94	$ 5.51
Oil and natural gas taxes	$ 6.02	$ 5.48	$ 4.09
General and administrative	$ 4.09	$ 4.41	$ 5.24
Depreciation, depletion and amortization	$ 18.21	$ 16.59	$ 18.89

(a) Includes the effect of cash settlements received from (paid on) commodity derivatives not designated as hedges and reported in operating costs and expenses. The following table reflects the amounts of cash settlements received from (paid on) commodity derivatives not designated as hedges that were included in computing average prices with derivatives and reconciles to the amount in loss on derivatives not designated as hedges as reported in the statements of operations:

	Years Ended December 31,		
(in thousands)	**2011**	**2010**	**2009**

Loss on derivatives not designated as hedges:			
Cash (payments on) receipts from oil derivatives	$ (103,969)	$ (26,281)	$ 74,796
Cash receipts from natural gas derivatives	25,739	17,414	10,955
Cash payments on interest rate derivatives	(6,624)	(4,957)	(3,335)
Unrealized mark-to-market gain (loss) on commodity and interest rate derivatives	61,504	(73,501)	(239,273)
Loss on derivatives not designated as hedges	$ (23,350)	$ (87,325)	$ (156,857)

The presentation of average prices with derivatives is a non-GAAP measure as a result of including the cash (payments on) receipts from commodity derivatives that are presented in loss on derivatives not designated as hedges in the statements of operations. This presentation of average prices with derivatives is a means by which to reflect the actual cash performance of our commodity derivatives for the respective periods and presents oil and natural gas prices with derivatives in a manner consistent with the presentation generally used by the investment community.

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The following table sets forth summary information from our discontinued operations concerning our production and operating data for the years ended December 31, 2011, 2010 and 2009. The discontinued operations presentation is the result of reclassifying the results of operations from the divestitures of our non-core Permian Basin assets in December 2010 and our Bakken assets in March 2011, which are more fully described in Note O of the Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data.

	Years Ended December 31,		
	2011	**2010**	**2009**
Production and operating data:			
Net production volumes:			
Oil (MBbl)	117	709	462
Natural gas (MMcf)	37	1,718	1,876
Total (MBoe)	123	995	775
Average daily production volumes:			
Oil (Bbl)	321	1,942	1,266
Natural gas (Mcf)	101	4,707	5,140
Total (Boe)	338	2,727	2,123
Average prices:			
Oil, without derivatives (Bbl)	$ 80.82	$ 70.95	$ 56.00
Natural gas, without derivatives (Mcf)	$ 1.84	$ 4.41	$ 4.16
Total, without derivatives (Boe)	$ 77.43	$ 58.17	$ 43.45
Operating costs and expenses per Boe:			
Lease operating expenses and workover costs	$ 3.85	$ 8.81	$ 9.76
Oil and natural gas taxes	$ 9.50	$ 5.60	$ 3.73
General and administrative [a]	$ -	$ (0.99)	$ (1.14)
Depreciation, depletion and amortization	$ 17.13	$ 15.74	$ 18.39

(a) Represents the fees received from third-parties for operating oil and natural gas properties that were sold. We reflect these fees as a reduction of general and administrative expenses.

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The following table presents selected production and operating data for the fields which represent greater than 15 percent of our total proved reserves at December 31, 2011, 2010 and 2009:

	Years Ended December 31,						
	2011			2010		2009	
	West Wolfberry	Yeso Central (a)	Yeso East (a)	West Wolfberry	Grayburg Jackson	West Wolfberry	Grayburg Jackson
Production and operating data:							
Net production volumes:							
Oil (MBbl)	2,735	3,923	2,848	1,643	1,680	1,320	1,429
Natural gas (MMcf)	7,794	14,124	8,058	4,679	4,696	3,361	4,180
Total (MBoe)	4,034	6,277	4,191	2,423	2,463	1,880	2,114
Average prices:							
Oil, without derivatives (Bbl)	$ 93.00	$ 91.51	$ 91.26	$ 77.74	$ 75.72	$ 58.30	$ 58.87
Natural gas, without derivatives (Mcf)	$ 8.82	$ 8.85	$ 7.78	$ 7.37	$ 7.59	$ 6.03	$ 5.76
Total, without derivatives (Boe)	$ 80.09	$ 77.11	$ 76.97	$ 66.95	$ 66.12	$ 51.72	$ 51.00
Production costs per Boe:							
Lease operating expenses including workovers	$ 4.71	$ 7.30	$ 9.03	$ 4.51	$ 6.24	$ 4.86	$ 4.47
Oil and natural gas taxes	$ 5.25	$ 6.78	$ 6.52	$ 4.32	$ 5.70	$ 3.77	$ 4.42

(a) These fields were acquired as part of the Marbob and Settlement Acquisitions in October 2010.

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Year Ended December 31, 2011 Compared to Year Ended December 31, 2010

Oil and natural gas revenues. Revenue from oil and natural gas operations was $1,740.0 million for the year ended December 31, 2011, an increase of $799.7 million (85 percent) from $940.3 million for the year ended December 31, 2010. This increase was primarily due to (i) 2011 having a full year effect of the Marbob and Settlement Acquisitions which closed in October 2010 and (ii) successful drilling efforts during 2010 and 2011, coupled with increases in realized oil and natural gas prices. Specific factors affecting oil and natural gas revenues include the following:

- total oil production was 14,575 MBbl for the year ended December 31, 2011, an increase of 4,954 MBbl (52 percent) from 9,621 MBbl for the year ended December 31, 2010;

- average realized oil price (excluding the effects of derivative activities) was $91.29 per Bbl during the year ended December 31, 2011, an increase of 19 percent from $76.43 per Bbl during the year ended December 31, 2010;

- total natural gas production was 53,677 MMcf for the year ended December 31, 2011, an increase of 23,990 MMcf (81 percent) from 29,687 MMcf for the year ended December 31, 2010; and

- average realized natural gas price (excluding the effects of derivative activities) was $7.63 per Mcf during the year ended December 31, 2011, an increase of 11 percent from $6.90 per Mcf during the year ended December 31, 2010. Our natural gas prices have been significantly higher than the related NYMEX prices primarily due to the value of the natural gas liquids in our liquids-rich natural gas stream.

Production expenses. The following table provides the components of our total oil and natural gas production costs for the years ended December 31, 2011 and 2010:

	Years Ended December 31,			
	2011		2010	
(in thousands, except per unit amounts)	**Amount**	**Per Boe**	**Amount**	**Per Boe**
Lease operating expenses	$ 163,109	$ 6.93	$ 83,709	$ 5.75
Taxes:				
Ad valorem	10,714	0.46	8,708	0.60
Production	130,726	5.56	71,167	4.88
Workover costs	3,462	0.15	2,825	0.19
Total oil and natural gas production expenses	$ 308,011	$ 13.10	$ 166,409	$ 11.42

Among the cost components of production expenses, we have some control over lease operating expenses and workover costs on properties we operate, but production and ad valorem taxes are directly related to commodity price changes.

Lease operating expenses for the year ended December 31, 2011 includes a $3.1 million ($0.13 per Boe) underestimate of costs related to periods prior to 2011.

Lease operating expenses were $163.1 million ($6.93 per Boe) for the year ended December 31, 2011 which was an increase of $79.4 million (95 percent) from $83.7 million ($5.75 per Boe) for the year ended December 31, 2010. The increase in lease operating expenses was primarily due to (i) 2011 having a full year effect from the Marbob and Settlement Acquisitions which closed in October 2010, (ii) our wells successfully drilled and completed in 2010 and 2011, (iii) an increase in cost of services, primarily labor related, due to the increased demand for services and related labor in the Permian Basin, (iv) incurring of higher than normal routine environmental related costs and (v) an underestimate of costs in periods prior to 2011 mentioned above. The increase in lease operating expenses per Boe was primarily due to (i) cost increases in services, primarily labor related, (ii) incurrence of higher than normal routine environmental related costs and (iii) an underestimate of costs in periods prior to 2011 mentioned above, offset in part by additional production from our wells successfully drilled and completed in 2010 and 2011 where we are receiving benefits from economies of scale.

Ad valorem taxes have increased primarily as a result of increased valuations of our Texas properties and the increase in our number of wells primarily associated with our 2010 and 2011 drilling activity in our Texas Permian area.

Production taxes per unit of production were $5.56 per Boe during the year ended December 31, 2011, an increase of 14 percent from $4.88 per Boe during the year ended December 31, 2010. The increase was directly related to the increase in commodity prices and our increase in oil and natural gas revenues related to increased volumes. Over the same period, our per Boe prices (excluding the effects of derivatives) increased 15 percent.

Workover expenses were approximately $3.5 million and $2.8 million for the years ended December 31, 2011 and 2010, respectively. The 2011 amounts related primarily to workovers in the Texas Permian area, while the 2010 amounts related to workovers in both the Texas Permian and New Mexico Shelf areas performed primarily to restore production.

Exploration and abandonments expense. The following table provides a breakdown of our exploration and abandonments expense for the years ended December 31, 2011 and 2010:

	Years Ended December 31,	
(in thousands)	**2011**	**2010**
Geological and geophysical	$ 4,977	$ 2,712
Exploratory dry holes	1,067	37
Leasehold abandonments and other	5,735	7,575
Total exploration and abandonments	$ 11,779	$ 10,324

Our geological and geophysical expense, which primarily consists of the costs of acquiring and processing seismic data, geophysical data and core analysis, was approximately $5.0 million and $2.7 million, primarily relating to our Delaware Basin and Texas Permian areas, for the years ended December 31, 2011 and 2010, respectively.

Our exploratory dry hole expense during the year ended December 31, 2011 was primarily attributable to partially expensing an exploratory well located in our Delaware Basin area. The lower portion of this well was deemed not commercial; however, the upper portion of this well was completed successfully.

For the year ended December 31, 2011, we recorded approximately $5.7 million of leasehold abandonments, which related to non-core prospects in our New Mexico Shelf area. For the year ended December 31, 2010, we recorded approximately $7.6 million of leasehold abandonments, which related to non-core prospects in our Delaware Basin and Texas Permian areas.

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Depreciation, depletion and amortization expense. The following table provides components of our depreciation, depletion and amortization expense for the years ended December 31, 2011 and 2010:

	Years Ended December 31,			
	2011		2010	
(in thousands, except per unit amounts)	**Amount**	**Per Boe**	**Amount**	**Per Boe**
Depletion of proved oil and natural gas properties	$ 421,126	$ 17.90	$ 236,989	$ 16.27
Depreciation of other property and equipment	5,702	0.24	3,104	0.21
Amortization of intangible asset - operating rights	1,549	0.07	1,549	0.11
Total depletion, depreciation and amortization	$ 428,377	$ 18.21	$ 241,642	$ 16.59
Oil price used to estimate proved oil reserves at period end (per Bbl)	$ 92.71		$ 75.96	
Natural gas price used to estimate proved natural gas reserves at period end (per MMBtu)	$ 4.12		$ 4.38	

Depletion of proved oil and natural gas properties was $421.1 million ($17.90 per Boe) for the year ended December 31, 2011, an increase of $184.1 million (78 percent) from $237.0 million ($16.27 per Boe) for the year ended December 31, 2010. The increase in depletion expense was primarily due to (i) capitalized costs associated with new wells that were successfully drilled and completed in 2011 and 2010 and (ii) 2011 having a full year effect from the Marbob and Settlement Acquisitions, offset in part by the increase in the oil prices between the periods utilized to determine proved reserves.

The amortization of the intangible asset is a result of the value assigned to the operating rights that we acquired in the July 2008 Henry Entities acquisition. The intangible asset is currently being amortized over an estimated life of 25 years.

Impairment of long-lived assets. We periodically review our long-lived assets to be held and used, including proved oil and natural gas properties accounted for under the successful efforts method of accounting. Due primarily to downward adjustments to the economically recoverable proved reserves associated with well performance on certain natural gas assets in our New Mexico Shelf area, we recognized a non-cash charge against earnings of $0.4 million during the year ended December 31, 2011. For the year ended December 31, 2010, we recognized a non-cash charge against earnings of $11.6 million, which was comprised primarily of natural gas related properties in our New Mexico Shelf area and to a lesser extent impairment in value of certain of our inventoried tubular goods.

General and administrative expenses. The following table provides components of our general and administrative expenses for the years ended December 31, 2011 and 2010:

	Years Ended December 31,			
	2011		2010	
(in thousands, except per unit amounts)	**Amount**	**Per Boe**	**Amount**	**Per Boe**
General and administrative expenses - recurring	$ 90,376	$ 3.84	$ 59,704	$ 4.09
Non-recurring bonus paid to Henry Entities employees	-	-	5,059	0.35

Non-cash stock-based compensation - stock options		880		0.04		2,653		0.18
Non-cash stock-based compensation - restricted stock		18,391		0.78		10,278		0.71
Less: Third-party operating fee reimbursements		(13,386)		(0.57)		(13,419)		(0.92)
Total general and administrative expenses	$	96,261	$	4.09	$	64,275	$	4.41

General and administrative expenses were $96.3 million ($4.09 per Boe) for year ended December 31, 2011, an increase of $32.0 million (50 percent) from $64.3 million ($4.41 per Boe) for the year ended December 31, 2010. The increase in general and administrative expenses was primarily due to (i) additional personnel and related costs associated with the Marbob Acquisition, (ii) an increase in the number of employees and related personnel expenses to handle our increased activities, partially offset by a decrease in the non-recurring bonus due to the Henry Entities employees (discussed in the next paragraph) and (iii) an increase in non-cash stock-based compensation for stock-based compensation awards. The decrease in total general and administrative expenses per Boe was primarily due to increased production associated with additional production from our wells successfully drilled and completed in 2010 and 2011 and 2011 having a full year effect of the production from our Marbob and Settlement Acquisitions.

In connection with the Henry Entities acquisition in July 2008, we agreed to pay certain of the Henry Entities former employees a predetermined bonus amount, in addition to the normal recurring compensation we pay these employees, at each of the first and second anniversaries of the closing of the acquisition. Since these employees earned this bonus over the two years following the acquisition and it is outside of our control, we are reflecting the cost in our general and administrative costs as non-recurring. The final payment of the Henry Entities bonuses occurred in July 2010.

As the operator of certain oil and natural gas properties in which we own an interest, we earn overhead reimbursements during the drilling and production phases of the property. We earned reimbursements of $13.4 million during the years ended December 31, 2011 and 2010. This reimbursement is reflected as a reduction of general and administrative expenses in the consolidated statements of operations. The per Boe rate decreased primarily due to increased production.

Loss on derivatives not designated as hedges. The following table sets forth the cash settlements and the non-cash mark-to-market adjustment for the derivative contracts not designated as hedges for the years ended December 31, 2011 and 2010:

	Years Ended December 31,	
(in thousands)	**2011**	**2010**
Cash payments (receipts):		
Commodity derivatives - oil	$ 103,969	$ 26,281
Commodity derivatives - natural gas	(25,739)	(17,414)
Financial derivatives - interest rate	6,624	4,957
Mark-to-market (gain) loss:		
Commodity derivatives - oil	(75,380)	93,595
Commodity derivatives - natural gas	19,630	(23,347)
Financial derivatives - interest rate	(5,754)	3,253
Loss on derivatives not designated as hedges	$ 23,350	$ 87,325

Our earnings are affected by the changes in value of our derivatives portfolio between periods and the related cash settlements of those derivatives, which can be volatile to our earnings. To the extent the future commodity price outlook declines between measurement periods, we will have mark-to-market gains, while to the extent future commodity price outlook increases between measurement periods, we will have mark-to-market losses.

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Interest expense. The following table sets forth interest expense, weighted average interest rates and weighted average debt balances for the years ended December 31, 2011 and 2010:

	Years Ended December 31,	
(dollars in thousands)	**2011**	**2010**
Interest expense	$ 118,360	$ 60,087
Weighted average interest rate	6.0%	5.1%
Weighted average debt balance	$ 1,812,984	$ 979,093

The increase in weighted average debt balance during the year ended December 31, 2011 was due primarily to borrowings in October 2010 for the Marbob and Settlement Acquisitions. The increase in interest expense was due to (i) the October 2010 borrowings related to the Marbob and Settlement Acquisitions and the issuance of the 8.0% Marbob note, which was repaid in May 2011, (ii) the December 2010 issuance of 7.0% senior notes due 2021, (iii) the May 2011 issuance of 6.5% senior notes due 2022 and (iv) the amortization of capitalized loan costs associated with debt financing and the Marbob note premium. The proceeds from the senior notes were used to pay down our credit facility. The increase in the weighted average cash interest rate is primarily due to the issuance of our senior notes, which bear a higher fixed interest rate than was available under our credit facility.

Income tax provisions. We recorded income tax expense of $285.8 million and $115.3 million for the years ended December 31, 2011 and 2010, respectively. The effective income tax rate for the years ended December 31, 2011 and 2010 was 38.3 percent and 40.3 percent, respectively, between periods.

We recorded an $8.3 million charge to income tax expense in the fourth quarter of 2010 to increase our estimated overall state tax rate utilized to record our net deferred tax liability. This increase in the tax rate is due to an increase in our overall blended state income tax rate, a result of the assets acquired in the Marbob and Settlement Acquisitions being located in New Mexico where the state income tax rate is higher than in Texas. Also, in 2010, we recorded a benefit of approximately $1.5 million associated with revisions to our 2009 income tax provision.

Excluding the effect of these items, our effective income tax rate would have been 38.0 percent in 2010, which would approximate a more normalized effective income tax rate.

Income from discontinued operations, net of tax. In December 2010, we closed the sale of certain of our non-core Permian Basin assets for cash consideration of $103.3 million. In March 2011, we closed our divestiture of our Bakken assets for cash consideration of approximately $195.9 million.

The results of operations of these assets and the related gain on disposition are reported as discontinued operations in the accompanying consolidated statements of operations, described in more detail in Note O of the Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data. We recognized income from discontinued operations of $87.5 million and $33.7 million for the years ended December 31, 2011 and 2010, respectively. For the years ended December 31, 2011 and 2010, income from discontinued operations included a pre-tax gain of $135.9 million on the sale of our Bakken assets and a pre-tax gain of $29.1 million on the sale of our non-core Permian Basin assets.

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

Oil and natural gas revenues. Revenue from oil and natural gas operations was $940.3 million for the year ended December 31, 2010, an increase of $429.5 million (84 percent) from $510.8 million for the year ended December 31, 2009. This increase was primarily due to increased production as a result of (i) the Wolfberry Acquisitions, (ii) the Marbob and Settlement Acquisitions which closed in October 2010 and (iii) the successful drilling efforts during 2009 and 2010, coupled with increases in realized oil and natural gas prices. Specific factors affecting oil and natural gas revenues include the following:

total oil production was 9,621 MBbl for the year ended December 31, 2010, an increase of 2,747 MBbl (40 percent) from 6,874 MBbl for the year ended December 31, 2009;

average realized oil price (excluding the effects of derivative activities) was $76.43 per Bbl during the year ended December 31, 2010, an increase of 32 percent from $58.12 per Bbl during the year ended December 31, 2009;

total natural gas production was 29,687 MMcf for the year ended December 31, 2010, an increase of 9,995 MMcf (51 percent) from 19,692 MMcf for the year ended December 31, 2009; and

average realized natural gas price (excluding the effects of derivative activities) was $6.90 per Mcf during the year ended December 31, 2010, an increase of 22 percent from $5.65 per Mcf during the year ended December 31, 2009. Our natural gas prices have been significantly higher than the related NYMEX prices primarily due to the value of the natural gas liquids in our liquids-rich natural gas stream.

Production expenses. The following table provides the components of our total oil and natural gas production costs for the years ended December 31, 2010 and 2009:

	Years Ended December 31,			
	2010		2009	
(in thousands, except per unit amounts)	**Amount**	**Per Boe**	**Amount**	**Per Boe**
Lease operating expenses	$ 83,709	$ 5.75	$ 55,094	$ 5.42
Taxes:				
Ad valorem	8,708	0.60	4,912	0.48
Production	71,167	4.88	36,707	3.61
Workover costs	2,825	0.19	954	0.09
Total oil and natural gas production expenses	$ 166,409	$ 11.42	$ 97,667	$ 9.60

Among the cost components of production expenses, we have some control over lease operating expenses and workover costs on properties we operate, but production and ad valorem taxes are directly related to commodity price changes.

Lease operating expenses were $83.7 million ($5.75 per Boe) for the year ended December 31, 2010 which was an increase of $28.6 million (52 percent) from $55.1 million ($5.42 per Boe) for the year ended December 31, 2009. The increase in lease operating expenses was primarily due to (i) our wells successfully drilled and completed in 2009 and 2010, (ii) additional interests acquired in the Wolfberry Acquisitions in December

2009 and (iii) the Marbob and Settlement Acquisitions which closed in October 2010. The increase in lease operating expenses per Boe was primarily due to (i) cost increases in services and supplies primarily related to increase in commodity prices and (ii) a reduction in our third-party income from utilization of our salt water disposal systems, in part due to our use of those systems, offset in part by additional production from our wells successfully drilled and completed in 2009 and 2010 where we are receiving benefits from economies of scale.

Ad valorem taxes have increased primarily as a result of increased valuations of our Texas properties and the increase in our number of wells primarily associated with the Wolfberry Acquisitions and 2009 and 2010 drilling activity.

Production taxes per unit of production were $4.88 per Boe during the year ended December 31, 2010, an increase of 35 percent from $3.61 per Boe during the year ended December 31, 2009. The increase was directly related to the increase in commodity prices and our increase in oil and natural gas revenues related to increased volumes coupled with a $2.2 million ($0.15 per Boe) increase in production taxes in 2010 related to prior year s taxes on one of our assets in our New Mexico Shelf area. Over the same period, our per Boe prices (excluding the effects of derivatives) increased 28 percent.

Workover expenses were approximately $2.8 million and $1.0 million for the years ended December 31, 2010 and 2009, respectively. The 2010 amounts related primarily to increased workovers during the first two quarters of 2010 in our New Mexico Shelf area due to work performed to restore production, whereas the 2009 amounts related primarily to workovers in our Texas Permian area.

Exploration and abandonments expense. The following table provides a breakdown of our exploration and abandonments expense for the years ended December 31, 2010 and 2009:

	Years Ended December 31,	
(in thousands)	**2010**	**2009**
Geological and geophysical	$ 2,712	$ 3,635
Exploratory dry holes	37	1,941
Leasehold abandonments and other	7,575	5,056
Total exploration and abandonments	$ 10,324	$ 10,632

Our geological and geophysical expense, which primarily consists of the costs of acquiring and processing seismic data, geophysical data and core analysis, was approximately $2.7 million and $3.6 million, primarily relating to the Texas Permian core area, for the years ended December 31, 2010 and 2009, respectively.

Our exploratory dry hole expense during the year ended December 31, 2009 was primarily attributable to an unsuccessful exploratory well located on our Arkansas acreage and two unsuccessful exploratory wells in our Texas Permian area.

For the year ended December 31, 2010, we recorded approximately $7.6 million of leasehold abandonments, which related to non-core prospects in our Delaware Basin and Texas Permian areas and abandonment costs related to specific wells in our New Mexico Shelf and Texas Permian areas. For the year ended December 31, 2009, we recorded $5.1 million of leasehold abandonments, which related primarily to the write-off of four prospects in our New Mexico Shelf area and three prospects in our Texas Permian area.

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Depreciation, depletion and amortization expense. The following table provides components of our depreciation, depletion and amortization expense for the years ended December 31, 2010 and 2009:

	Years Ended December 31,			
	2010		2009	
(in thousands, except per unit amounts)	Amount	Per Boe	Amount	Per Boe
Depletion of proved oil and natural gas properties	$ 236,989	$ 16.27	$ 187,654	$ 18.48
Depreciation of other property and equipment	3,104	0.21	2,680	0.26
Amortization of intangible asset - operating rights	1,549	0.11	1,555	0.15
Total depletion, depreciation and amortization	$ 241,642	$ 16.59	$ 191,889	$ 18.89
Oil price used to estimate proved oil reserves at period end (per Bbl)	$ 75.96		$ 57.65	
Natural gas price used to estimate proved natural gas reserves at period end (per MMBtu)	$ 4.38		$ 3.87	

Depletion of proved oil and natural gas properties was $237.0 million ($16.27 per Boe) for the year ended December 31, 2010, an increase of $49.3 million (26 percent) from $187.7 million ($18.48 per Boe) for the year ended December 31, 2009. The increase in depletion expense was primarily due to (i) capitalized costs associated with new wells that were successfully drilled and completed in 2009 and 2010, (ii) the Wolfberry Acquisitions and (iii) the Marbob and Settlement Acquisitions, offset in part by the increase in the oil and natural gas prices between the periods utilized to determine proved reserves. The decrease in depletion expense per Boe was primarily due to (i) the increase in the oil and natural gas prices between the periods utilized to determine proved reserves, (ii) the increase in proved reserves from the successful 2009 and 2010 drilling of unproved properties, (iii) the proved finding costs associated with the Marbob and Settlement Acquisitions and (iv) the increase in total proved reserves due to the SEC rules adopted at the end of 2009 related to disclosures of oil and natural gas reserves.

On December 31, 2009, we adopted the SEC rules related to disclosures of oil and natural gas reserves. As a result of these SEC rules we recorded an additional 13.6 MMBoe of proved reserves. We utilized the additional proved reserves beginning in our depletion computation in the fourth quarter of 2009. Our fourth quarter of 2009 depletion expense rate was $16.74 per Boe, which was lower than past quarters in part due to these additional proved reserves. Comparisons between years as it relates to our depletion rate are difficult as a result of these rules.

The amortization of the intangible asset is a result of the value assigned to the operating rights that we acquired in the July 2008 Henry Entities acquisition. The intangible asset is currently being amortized over an estimated life of 25 years.

Impairment of long-lived assets. We periodically review our long-lived assets to be held and used, including proved oil and natural gas properties accounted for under the successful efforts method of accounting. Due primarily to downward adjustments to the economically recoverable proved reserves associated with well performance, we recognized a non-cash charge against earnings of $11.6 million during the year ended December 31, 2010, which was primarily attributable to natural gas related properties in our New Mexico Shelf area and to a lesser extent impairment in value of certain of our inventoried tubular goods. For the year ended December 31, 2009, we recognized a non-cash charge against earnings of $7.9 million, which was comprised primarily of natural gas related properties in our New Mexico Shelf area.

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General and administrative expenses. The following table provides components of our general and administrative expenses for the years ended December 31, 2010 and 2009:

	Years Ended December 31,			
	2010		2009	
(in thousands, except per unit amounts)	Amount	Per Boe	Amount	Per Boe
General and administrative expenses - recurring	$ 59,704	$ 4.09	$ 44,475	$ 4.38
Non-recurring bonus paid to Henry Entities employees	5,059	0.35	10,150	1.00
Non-cash stock-based compensation - stock options	2,653	0.18	4,285	0.42
Non-cash stock-based compensation - restricted stock	10,278	0.71	4,755	0.47
Less: Third-party operating fee reimbursements	(13,419)	(0.92)	(10,502)	(1.03)
Total general and administrative expenses	$ 64,275	$ 4.41	$ 53,163	$ 5.24

General and administrative expenses were $64.3 million ($4.41 per Boe) for year ended December 31, 2010, an increase of $11.1 million (21 percent) from $53.2 million ($5.24 per Boe) for the year ended December 31, 2009. The increase in general and administrative expenses was primarily due to (i) an increase in non-cash stock-based compensation for stock-based compensation awards, (ii) additional personnel and related costs associated with the Marbob Acquisition and (iii) an increase in the number of employees and related personnel expenses to handle our increased activities, partially offset by (i) a decrease in the non-recurring bonus due to the Henry Entities employees (discussed in the next paragraph) and (ii) an increase in third-party operating fee reimbursements. The decrease in total general and administrative expenses per Boe was primarily due to increased production associated with (i) additional production from our wells successfully drilled and completed in 2009 and 2010, (ii) additional production from our Wolfberry Acquisitions for which we added no administrative personnel and (iii) the production from our the Marbob and Settlement Acquisitions.

In connection with the Henry Entities acquisition in July 2008, we agreed to pay certain of the Henry Entities former employees a predetermined bonus amount, in addition to the normal recurring compensation we pay these employees, at each of the first and second anniversaries of the closing of the acquisition. Since these employees earned this bonus over the two years following the acquisition and it is outside of our control, we are reflecting the cost in our general and administrative costs as non-recurring. The final payment of the Henry Entities bonuses occurred in July 2010.

We earn reimbursements as operator of certain oil and natural gas properties in which we own interests. As such, we earned reimbursements of $13.4 million and $10.5 million during the years ended December 31, 2010 and 2009, respectively, which increased primarily as a result of additional operated properties from our drilling and acquisitions. This reimbursement is reflected as a reduction of general and administrative expenses in the consolidated statements of operations.

Bad debt expense. In May 2008, we entered into a short-term purchase agreement with an oil purchaser to buy a portion of our oil affected as a result of a New Mexico refinery shut down due to repairs. In July 2008, this purchaser declared bankruptcy. We fully reserved the receivable amount due from this purchaser of approximately $2.9 million as of December 31, 2008, and pursued a claim in the bankruptcy proceedings. In December 2009, we recovered approximately $1.0 million and accordingly reduced our allowance for bad debts and bad debt expense.

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Loss on derivatives not designated as hedges. The following table sets forth the cash settlements and the non-cash mark-to-market adjustment for the derivative contracts not designated as hedges for the years ended December 31, 2010 and 2009:

(in thousands)	Years Ended December 31, 2010	2009
Cash payments (receipts):		
Commodity derivatives - oil	$ 26,281	$ (74,796)
Commodity derivatives - natural gas	(17,414)	(10,955)
Financial derivatives - interest rate	4,957	3,335
Mark-to-market (gain) loss:		
Commodity derivatives - oil	93,595	229,896
Commodity derivatives - natural gas	(23,347)	7,959
Financial derivatives - interest rate	3,253	1,418
Loss on derivatives not designated as hedges	$ 87,325	$ 156,857

Our earnings are affected by the changes in value of our derivatives portfolio between periods and the related cash settlements of those derivatives, which can be volatile to our earnings. To the extent the future commodity price outlook declines between measurement periods we will have mark-to-market gains, while to the extent future commodity price outlook increases between measurement periods we will have mark-to-market losses.

Interest expense. The following table sets forth interest expense, weighted average interest rates and weighted average debt balances for the years ended December 31, 2010 and 2009:

(dollars in thousands)	Years Ended December 31, 2010	2009
Interest expense	$ 60,087	$ 28,292
Weighted average interest rate	5.1%	3.4%
Weighted average debt balance	$ 979,093	$ 667,993

The increase in weighted average debt balance during the year ended December 31, 2010, was due primarily to borrowings in October 2010 for the Marbob and Settlement Acquisitions. The increase in interest expense is due to an increase in the weighted average debt balance. The increase in the weighted average interest rate is primarily due to the issuance of our senior notes.

In September 2009, we issued $300 million of 8.625% senior notes at a discount, resulting in a yield-to-maturity of 8.875 percent. The interest rate associated with the senior notes was higher than the credit facility, which resulted in us having higher absolute interest rates.

Income tax provisions. We recorded income tax expense of $115.3 million and an income tax benefit of $22.6 million for the years ended December 31, 2010 and 2009, respectively. The effective income tax rate for the years ended December 31, 2010 and 2009 was 40.3 percent and 62.9 percent, respectively, between periods.

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We recorded an $8.3 million charge to income tax expense in the fourth quarter of 2010 to increase our estimated overall state tax rate utilized to record our net deferred tax liability. This increase in the tax rate is due to an increase in our overall blended state income tax rate, a result of the assets acquired in the Marbob and Settlement Acquisitions being located in New Mexico where the state income tax rate is higher than in Texas. Also, in 2010, we recorded a benefit of approximately $1.5 million associated with revisions to our 2009 income tax provision.

In 2009, we recorded a tax benefit of approximately $6.6 million associated with a reduction in our estimated overall state tax rate and the related effect on our net deferred tax liability. In 2009, we made the Wolfberry Acquisitions, the assets of which were primarily in the state of Texas. The state income tax rate is lower in Texas compared to New Mexico (the location of our other significant concentration of assets). Accordingly, this has caused a reduction of our overall estimated state income tax rate due to the addition of Texas assets. Also, in 2009, we recorded a benefit of approximately $1.6 million associated with revisions to our 2008 tax provision.

Excluding the effect of these two items our effective income tax rate would have been 38.0 percent and 40.3 percent in 2010 and 2009, respectively, which would approximate a more normalized effective income tax rate.

Income (loss) from discontinued operations, net of tax. In December 2010, we closed the sale of certain of our non-core Permian Basin assets for cash consideration of $103.3 million. In March 2011, we closed our divestiture of our Bakken assets for cash consideration of approximately $195.9 million and recognized a pre-tax gain, in 2011, on this sale of approximately $135.9 million.

The results of operations of these assets and the related gain on disposition are reported as discontinued operations in the accompanying consolidated statements of operations, described in more detail in Note O of the Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data. We recognized income from discontinued operations of $33.7 million and $3.5 million for the years ended December 31, 2010 and 2009, respectively. In 2010, income from discontinued operations included a pre-tax gain of the sale of the non-core Permian Basin assets of $29.1 million.

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Capital Commitments, Capital Resources and Liquidity

Capital commitments. Our primary needs for cash are development, exploration and acquisition of oil and natural gas assets, payment of contractual obligations and working capital obligations. Funding for these cash needs may be provided by any combination of internally-generated cash flow, financing under our credit facility or proceeds from the disposition of assets or alternative financing sources, as discussed in Capital resources below.

Oil and natural gas properties. Our costs incurred on oil and natural gas properties, excluding acquisitions and asset retirement obligations, during the years ended December 31, 2011, 2010 and 2009 totaled $1.3 billion, $679.0 million and $394.0 million, respectively. The primary reason for the differences in the costs incurred and cash flow for these expenditures is the timing of payments. The 2011 expenditures were funded in part from borrowings under our credit facility and proceeds from the sale of assets. In October 2010, we closed the Marbob and Settlement Acquisitions, which was the primary reason for the increase in our costs incurred on oil and natural gas properties in 2010 and the related drilling on those assets in 2011.

In November 2011, we announced our 2012 capital budget of approximately $1.3 billion, which was subsequently revised to $1.37 billion in connection with the PDC Acquisition (exclusive of $175 million PDC Acquisition purchase price). We expect it to be funded within our cash flow, based on current commodity prices and capital costs. Cost inflation has been experienced industry-wide and particularly in the Permian Basin due to the increased activity levels.

Although we cannot provide any assurance, we generally attempt to fund our non-acquisition expenditures with our available cash and cash flow as adjusted from time to time; however, we may also use our credit facility, or other alternative financing sources, to fund such expenditures. The actual amount and timing of our expenditures may differ materially from our estimates as a result of, among other things, actual drilling results, the timing of expenditures by third parties on projects that we do not operate, the availability of drilling rigs and other services and equipment, regulatory, technological and competitive developments and market conditions. In addition, under certain circumstances we would consider increasing or reallocating our capital spending plans.

Other than the customary purchase of leasehold acreage, our 2012 capital budget is exclusive of acquisitions. We do not have a specific acquisition budget, since the timing and size of acquisitions are difficult to forecast. We evaluate opportunities to purchase or sell oil and natural gas properties in the marketplace and could participate as a buyer or seller of properties at various times. We seek to acquire oil and natural gas properties that provide opportunities for the addition of reserves and production through a combination of development, high-potential exploration and control of operations that will allow us to apply our operating expertise.

Acquisitions. Our expenditures for acquisitions of proved and unproved properties during the years ended December 31, 2011, 2010 and 2009 totaled $525.0 million, $1.7 billion and $280.5 million, respectively. In 2011, the $332 million of Delaware Basin Acquisitions were funded by borrowings under our credit facility. Also in 2011, expenditures for customary leasehold acquisitions (which are expenditures we generally provide for in our budget) included in the total were approximately $88.8 million. In 2010, the Marbob Acquisition consideration was comprised of (i) approximately $1.1 billion in cash which was funded with borrowings under our credit facility and with net proceeds of a $292.7 million private placement of 6.6 million shares of our common stock, (ii) issuance of 1.1 million shares of our common stock to the sellers and (iii) issuance of a $150 million 8.0% senior note due 2018 to the sellers. The Settlement Acquisition, also completed in October 2010, was funded with borrowings under our credit facility. The Wolfberry Acquisitions in December 2009 were funded by borrowings under our credit facility.

Divestitures. In December 2010, we sold certain of our non-core Permian Basin assets for cash consideration of approximately $103.3 million and recognized a pre-tax gain on the disposition of assets (included in discontinued operations) of approximately $29.1 million. For 2010, these assets produced an average of 1,393 Boe per day. The proved reserves of these assets were approximately 6.0 MMBoe at closing. We used the net proceeds from this divestiture to repay a portion of the outstanding borrowings under our credit facility.

In March 2011, we sold our Bakken assets for cash consideration of approximately $195.9 million and recognized a pre-tax gain on the disposition of assets (included in discontinued operations) of approximately $135.9 million. For the first quarter of 2011, these assets produced an average of 1,369 Boe per day. The proved reserves of the Bakken assets at closing were approximately 8.4 MMBoe.

Contractual obligations. Our contractual obligations include long-term debt, cash interest expense on debt, operating lease obligations, drilling commitments, employment agreements with executive officers, derivative liabilities and other obligations.

We had the following contractual obligations at December 31, 2011:

		Payments Due by Period			
(in thousands)	Total	Less than 1 year	1 - 3 years	3 - 5 years	More than 5 years
Long-term debt [a]	$ 2,083,500	$ -	$ -	$ 583,500	$ 1,500,000
Cash interest expense on debt [b]	1,027,473	172,137	255,319	213,750	386,267
Operating lease obligations [c]	13,589	3,772	7,938	1,879	-
Drilling commitments [d]	8,179	6,919	1,260	-	-
Employment agreements with officers [e]	3,585	3,585	-	-	-
Derivative liabilities [f]	88,472	56,218	32,254	-	-
Asset retirement obligations [g]	59,685	7,445	2,259	2,139	47,842
Total contractual obligations	$ 3,284,483	$ 250,076	$ 299,030	$ 801,268	$ 1,934,109

(a) See Note J of the Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data for information regarding future interest payment obligations on our senior notes. The amounts included in the table above represent principal maturities only.

(b) Cash interest expense on our senior notes is estimated assuming no principal repayment until their maturity dates. Cash interest expense on our credit facility is estimated assuming (i) a principal balance outstanding equal to the balance at December 31, 2011 of $583.5 million with no principal repayment until the instrument due date of April 25, 2016 and (ii) a fixed interest rate of 2.1 percent, which was our interest rate at December 31, 2011. Also included in the Less than 1 year column is accrued interest at December 31, 2011 for our senior notes and the credit facility of approximately $52.7 million.

(c) See Note K of the Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data.

(d) Consists of daywork drilling contracts related to drilling rigs contracted at December 31, 2011. See Note K of the Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data.

(e) Represents amounts of cash compensation we are obligated to pay to our officers under employment agreements assuming such employees continue to serve the entire term of their employment agreement and their cash compensation is not adjusted.

(f)

Derivative obligations represent commodity derivatives that were valued at December 31, 2011. The ultimate settlement amounts of our derivative obligations are unknown because they are subject to continuing market risk. See Item 7A. Quantitative and Qualitative Disclosures About Market Risk and Note I of the Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data for additional information regarding our derivative obligations.

(g) Amounts represent costs related to expected oil and natural gas property abandonments related to proved reserves by period, net of any future accretion. See Note E of the Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data.

Off-balance sheet arrangements. Currently, we do not have any material off-balance sheet arrangements.

Capital resources. Our primary sources of liquidity have been cash flows generated from operating activities (including the cash settlements received from (paid on) derivatives not designated as hedges presented in our investing activities) and financing provided by our credit facility. We currently believe that our cash flows will substantially meet both our short-term working capital requirements and our current 2012 capital expenditure plans. We believe we have adequate availability under our credit facility to fund any cash flow deficits, though we could reduce our capital spending program to remain substantially within our cash flow.

The following table summarizes our net decrease in cash and cash equivalents for the years ended December 31, 2011, 2010 and 2009:

	Years Ended December 31,		
(in thousands)	**2011**	**2010**	**2009**
Net cash provided by operating activities	$ 1,199,458	$ 651,582	$ 359,546
Net cash used in investing activities	(1,651,418)	(2,043,457)	(586,148)
Net cash provided by financing activities	451,918	1,389,025	212,084
Net decrease in cash and cash equivalents	$ (42)	$ (2,850)	$ (14,518)

Cash flow from operating activities. The increase in operating cash flows during the year ended December 31, 2011 over 2010 was principally due to increases in our oil and natural gas production as a result of our (i) exploration and development program and (ii) 2011 having a full year effect from the Marbob and Settlement Acquisitions and increases in average realized oil and natural gas prices, offset by increases in oil and natural gas production costs. The increase in operating cash flows during the year ended December 31, 2010 over 2009 was principally due to (i) our exploration and development program, (ii) the Wolfberry Acquisitions in December 2009 and (iii) the Marbob and Settlement Acquisitions closed in October 2010, and increases in average realized oil and natural gas prices.

Our net cash provided by operating activities also includes a reduction of $19.6 million, a reduction of $29.2 million and an increase of $5.0 million for the years ended December 31, 2011, 2010 and 2009, respectively, associated with changes in working capital items. Changes in working capital items adjust for the timing of receipts and payments of actual cash.

Cash flow used in investing activities. During the years ended December 31, 2011, 2010 and 2009, we invested $1.7 billion, $2.1 billion and $0.7 billion, respectively, for capital expenditures on oil and natural gas properties. Cash flows used in investing activities were higher during the year ended December 31, 2010 over 2011, primarily due to the size of the Marbob and Settlement Acquisitions in 2010 compared to acquisitions in 2011, offset by the significant increase in drilling activity in 2011. Cash flows used in investing activities were substantially higher during the year ended December 31, 2010 over 2009 primarily due to the Marbob and Settlement Acquisitions in 2010 compared to the acquisitions in 2009 and increased drilling activity in 2010.

Cash flow from financing activities. Below is a description of our financing activities. During 2011, 2010 and 2009 we completed the following significant capital markets activities:

in May 2011, we issued $600 million in principal amount of 6.5% senior notes due 2022 at par, and we received net proceeds of approximately $587.1 million. We used the net proceeds to repay a portion of the borrowings under our credit facility;

in December 2010, we issued, in a secondary public offering, 2.9 million shares of our common stock at $82.50 per share, and we received net proceeds of approximately $227.4 million. We used the net proceeds from this offering to repay a portion of the borrowings under our credit facility;

in December 2010, we issued $600 million in principal amount of 7.0% senior notes due 2021 at par, and we received net proceeds of approximately $587.4 million. We used the net proceeds from this offering to repay a portion of the borrowings under our credit facility;

in October 2010, we closed the private placement of our common stock, simultaneously with the closing of the Marbob Acquisition, on 6.6 million shares of our common stock at a price of $45.30 per share for net proceeds of approximately $292.7 million;

in February 2010, we issued approximately 5.3 million shares of our common stock at $42.75 per share in a secondary public offering, and we received net proceeds of approximately $219.3 million. The net proceeds from this offering were used to repay a portion of the borrowings under our credit facility; and

in September 2009, we issued $300 million of 8.625% senior notes at a discount, resulting in a yield-to-maturity of 8.875 percent. The net proceeds from this offering were used to repay a portion of the borrowings under our credit facility.

In 2011, we amended our credit facility to increase the borrowing base from $2.0 billion to $2.5 billion and maintained our commitments from our bank group at $2.0 billion. The next scheduled borrowing base redetermination will be in April 2012. Between scheduled borrowing base redeterminations, we and, if requested by 66 2/3 percent of the lenders, the lenders, may each request one special redetermination. Our credit facility has a maturity date of April 25, 2016. At December 31, 2011, our availability to borrow additional funds was approximately $1.4 billion based on the bank commitments of $2.0 billion.

Advances on our credit facility bear interest, at our option, based on (i) the prime rate of JPMorgan Chase Bank (JPM Prime Rate) (3.25 percent at December 31, 2011) or (ii) a Eurodollar rate (substantially equal to the London Interbank Offered Rate). The credit facility s interest rates of Eurodollar rate advances and JPM Prime Rate advances varied, with interest margins ranging from 150 to 250 basis points and 50 to 150 basis points, respectively, per annum depending on the debt balance outstanding. We pay commitment fees on the unused portion of the available commitment ranging from 37.5 to 50 basis points per annum, depending on utilization of the commitments.

In conducting our business, we may utilize various financing sources, including the issuance of (i) fixed and floating rate debt, (ii) convertible securities, (iii) preferred stock, (iv) common stock and (v) other securities. Over the last three years, we have demonstrated our use of the capital markets by issuing common stock in public offerings and private placements and issuing senior unsecured debt. However, there are no assurances that we can access the capital markets to obtain additional funding, if needed, and at what cost and terms. We may also sell assets and issue securities in exchange for oil and natural gas assets or interests in oil and natural gas companies. Additional securities may be of a class senior to common stock with respect to such matters as dividends and liquidation rights and may also have other rights and preferences as determined from time to time by our board of directors. Utilization of some of these financing sources may require approval from the lenders under our credit facility.

Liquidity. Our principal sources of short-term liquidity are cash on hand and available borrowing capacity under our credit facility. At December 31, 2011, we had $0.3 million of cash on hand.

At December 31, 2011, the commitments under our credit facility were $2.0 billion, which provided us with approximately $1.4 billion of available borrowing capacity. In 2011, we amended our credit facility, which primarily (i) increased our borrowing base $500 million to $2.5 billion (leaving our $2.0 billion in commitments from our bank group in place) until the next borrowing base redetermination in April 2012, (ii) extended maturity approximately three years to April 2016, (iii) improved our pricing grid and (iv) allowed us to issue up to an additional $1.0 billion in senior notes.

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Upon a redetermination, our borrowing base could be substantially reduced. There is no assurance that our borrowing base will not be reduced, which could affect our liquidity.

Debt ratings. We receive debt credit ratings from Standard & Poor s Ratings Group, Inc. (S&P) and Moody s Investors Service, Inc. (Moody s) which are subject to regular reviews. S&P s corporate rating for us is BB+ with a stable outlook. Moody s corporate rating for us is B1 with a stable outlook. S&P and Moody s consider many factors in determining our ratings including: production growth opportunities, liquidity, debt levels and asset and reserve mix. A reduction in our debt ratings could negatively affect our ability to obtain additional financing or the interest rate, fees and other terms associated with such additional financing.

Book capitalization and current ratio. Our book capitalization at December 31, 2011 was $5.1 billion, consisting of debt of $2.1 billion and stockholders equity of $3.0 billion. Our debt to book capitalization was 41 percent at December 31, 2011 and 2010. Our ratio of current assets to current liabilities was 0.59 to 1.00 at December 31, 2011 as compared to 0.65 to 1.00 at December 31, 2010.

Inflation and changes in prices. Our revenues, the value of our assets, and our ability to obtain bank financing or additional capital on attractive terms have been and will continue to be affected by changes in commodity prices and the costs to produce our reserves. Commodity prices are subject to significant fluctuations that are beyond our ability to control or predict. During the year ended December 31, 2011, we received, from continuing operations, an average of $91.29 per barrel of oil and $7.63 per Mcf of natural gas before consideration of commodity derivative contracts compared to $76.43 per barrel of oil and $6.90 per Mcf of natural gas in the year ended December 31, 2010. Although certain of our costs are affected by general inflation, inflation does not normally have a significant effect on our business. In a trend that began in 2004, and that has continued, oil prices have increased significantly. The higher oil price led to increased activity in the industry and, consequently, rising costs. These cost trends have put pressure not only on our operating costs, but also on capital costs.

Critical Accounting Policies and Practices

Our historical consolidated financial statements and related notes to consolidated financial statements contain information that is pertinent to our management s discussion and analysis of financial condition and results of operations. Preparation of financial statements in conformity with accounting principles generally accepted in the United States requires that our management make estimates, judgments and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and the disclosure of contingent assets and liabilities. However, the accounting principles used by us generally do not change our reported cash flows or liquidity. Interpretation of the existing rules must be done and judgments made on how the specifics of a given rule apply to us.

In management s opinion, the more significant reporting areas impacted by management s judgments and estimates are revenue recognition, the choice of accounting method for oil and natural gas activities, oil and natural gas reserve estimation, asset retirement obligations, impairment of long-lived assets, valuation of stock-based compensation, valuation of business combinations and valuation of financial derivative instruments. Management s judgments and estimates in these areas are based on information available from both internal and external sources, including engineers, geologists and historical experience in similar matters. Actual results could differ from the estimates, as additional information becomes known.

Successful Efforts Method of Accounting

We utilize the successful efforts method of accounting for our oil and natural gas exploration and development activities. Under this method, exploration expenses, including geological and geophysical costs, lease rentals and exploratory dry holes, are charged against income as incurred. Costs of successful wells and related production equipment, undeveloped leases and developmental dry holes are capitalized. Exploratory drilling costs are initially capitalized, but are charged to expense if and when the well is determined not to have found proved reserves. Generally, a gain or loss is recognized when producing properties are sold. This accounting method may yield significantly different results than the full cost method of accounting.

The application of the successful efforts method of accounting requires management s judgment to determine the proper designation of wells as either developmental or exploratory, which will ultimately determine the proper accounting treatment of costs of dry holes. Once a well is drilled, the determination that proved reserves have been discovered may take considerable time, and requires both judgment and application of industry experience. The evaluation of oil and natural gas leasehold acquisition costs included in unproved properties requires management s judgment to estimate the fair value of such properties. Drilling activities in an area by other companies may also effectively condemn our leasehold positions.

Non-producing properties consist of undeveloped leasehold costs and costs associated with the purchase of certain proved undeveloped reserves. Individually significant non-producing properties or projects are periodically assessed for impairment of value by considering future drilling plans, the results of exploration activities, commodity price outlooks, planned future sales or expiration of all or a portion of such projects.

Depletion of capitalized drilling and development costs of oil and natural gas properties is computed using the unit-of-production method on a field basis based on total estimated proved developed oil and natural gas reserves. Depletion of producing leaseholds is based on the unit-of-production method using our total estimated proved reserves. In arriving at rates under the unit-of-production method, the quantities of recoverable oil and natural gas are established based on estimates made by our geologists and engineers and independent engineers. Service properties, equipment and other assets are depreciated using the straight-line method over estimated useful lives of 1 to 50 years. Upon sale or retirement of depreciable or depletable property, the cost and related accumulated depreciation and depletion are eliminated from the accounts and the resulting gain or loss is recognized.

Oil and Natural Gas Reserves and Standardized Measure of Discounted Net Future Cash Flows

This report presents estimates of our proved reserves as of December 31, 2011, which have been prepared and presented under the SEC rules which became effective December 31, 2009. These rules are effective for fiscal years ending on or after December 31, 2009, and require SEC reporting companies to prepare their reserves estimates using revised reserve definitions and revised pricing based on a 12-month unweighted average of the first-day-of-the-month pricing. The previous rules required that reserve estimates be calculated using last-day-of-the-year pricing. The pricing that was used for estimates of our reserves as of December 31, 2011 was based on an unweighted average twelve month West Texas Intermediate posted price of $92.71 per Bbl for oil and a Henry Hub spot natural gas price of $4.12 per MMBtu for natural gas. As a result of this change in pricing methodology, direct comparisons to our reported reserves amounts prior to 2009 may be more difficult.

Another impact of the SEC rules is a general requirement that, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking. This rule has limited and may continue to limit our potential to book additional proved undeveloped reserves as we pursue our drilling program, particularly as we develop our significant acreage in the Permian Basin of Southeast New Mexico and West Texas. Moreover, we may be required to write down our proved undeveloped reserves if we do not drill on those reserves within the required five-year time-frame.

Our independent engineers and technical staff prepare the estimates of our oil and natural gas reserves and associated future net cash flows. Even though our independent engineers and technical staff are knowledgeable and follow authoritative guidelines for estimating reserves, they must make a number of subjective assumptions based on professional judgments in developing the reserve estimates. Reserve estimates are updated at least annually and consider recent production levels and other technical information about each field. Periodic revisions to the estimated reserves and future net cash flows may be necessary as a result of a number of factors, including reservoir performance, new drilling, oil and natural gas prices, cost changes, technological advances, new geological or geophysical data, or other economic factors. We cannot predict the amounts or timing of future reserve revisions. If such revisions are significant, they could significantly alter future depletion and result in impairment of long-lived assets that may be material.

Asset Retirement Obligations

There are legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and the normal operation of a long-lived asset. The primary impact of this relates to oil and natural gas wells on which we have a legal obligation to plug and abandon. We record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and, generally, a corresponding increase in the carrying amount of the related long-lived asset. The determination of the fair value of the liability requires us to make numerous judgments and estimates, including judgments and estimates related to future costs to plug and abandon wells, future inflation rates and estimated lives of the related assets.

Impairment of Long-Lived Assets

All of our long-lived assets are monitored for potential impairment when circumstances indicate that the carrying value of an asset may be greater than its future net cash flows, including cash flows from risk adjusted proved reserves. The evaluations involve a significant amount of judgment since the results are based on estimated future events, such as future sales prices for oil and natural gas, future costs to produce these products, estimates of future oil and natural gas reserves to be recovered and the timing thereof, the economic and regulatory climates and other factors. The need to test an asset for impairment may result from significant declines in sales prices or downward revisions in estimated quantities of oil and natural gas reserves. Any assets held for sale are reviewed for impairment when we approve the plan to sell. Estimates of anticipated sales prices are highly judgmental and subject to material revision in future periods. Because of the uncertainty inherent in these factors, we cannot predict when or if future impairment charges will be recorded.

Valuation of Stock-Based Compensation

Under the modified prospective accounting approach, we are required to expense all options and other stock-based compensation that vested during the year of adoption based on the fair value of the award on the grant date. The calculation of the fair value of stock-based compensation requires the use of estimates to derive the inputs necessary for using the various valuation methods utilized by us. We utilize (i) the Black-Scholes option pricing model to measure the fair value of stock options and (ii) the average of the high and low stock price on the date of grant for the fair value of restricted stock awards.

Valuation of Business Combinations

In connection with a purchase business combination, the acquiring company must record assets acquired and liabilities assumed based on fair values as of the acquisition date. Deferred taxes must be recorded for any differences between the assigned values and tax bases of assets and liabilities. Any excess of purchase price over amounts assigned to assets and liabilities is recorded as goodwill. The amount of goodwill recorded in any particular business combination can vary significantly depending upon the value attributed to assets acquired and liabilities assumed.

In estimating the fair values of assets acquired and liabilities assumed, we make various assumptions. The most significant assumptions related to the estimated fair values assigned to proved and unproved oil and natural gas properties. To estimate the fair values of these properties, we utilize estimates of oil and natural gas reserves. We make future price assumption to apply to the estimated reserves quantities acquired and estimate future operating and development costs to arrive at estimates of future net cash flows. For estimated proved reserves, the future net cash flows were discounted using a market-based weighted average cost of capital rates determined appropriate at the time of the acquisition. The market-based weighted average cost of capital rates are subject to additional project-specific risking factors. To compensate for the inherent risk of estimating and valuing unproved reserves, the discounted future net cash flows of the unproved reserves were reduced by additional risk-weighting factors.

Estimated fair values assigned to assets acquired can have a significant effect on results of operations in the future. A higher fair value assigned to a property results in a higher depletion expense, which results in lower net earnings. Fair values are based on estimates of future commodity prices, reserves quantities, operating expenses and development costs. This increases the likelihood of impairment if future commodity prices or reserves quantities are lower than those originally used to determine fair value, or if future operating expenses or development costs are higher than those originally used to determine fair value. Impairment would have no effect on cash flows but would result in a decrease in net income for the period in which the impairment is recorded.

Valuation of Financial Derivative Instruments

In order to reduce commodity price uncertainty and increase cash flow predictability relating to the marketing of our oil and natural gas, we enter into oil and natural gas price hedging arrangements with respect to a portion of our expected production. In addition, we have used derivative instruments in connection with acquisitions and certain price-sensitive projects. Management exercises significant judgment in determining the types of instruments to be used, production volumes to be hedged, prices at which to hedge and the counterparties creditworthiness. All derivative instruments are reflected at fair value in our consolidated balance sheets.

Our open commodity derivative instruments were in a net liability position with a fair value of $78.8 million at December 31, 2011. In order to determine the fair value at the end of each reporting period, we compute discounted cash flows for the duration of each commodity derivative instrument using the terms of the related contract. Inputs consist of published forward commodity price curves as of the date of the estimate. We compare these prices to the price parameters contained in our hedge contracts to determine estimated future cash inflows or outflows. We then discount the cash inflows or outflows using a combination of published LIBOR rates, Eurodollar futures rates and interest swap rates. The fair values of our commodity derivative assets and liabilities include a measure of credit risk based on current published credit default swap rates. In addition, for collars, we estimate the option value of the contract floors and ceilings using an option pricing model which takes into account market volatility, market prices and contract parameters.

Changes in the fair values of our commodity derivative instruments have a significant impact on our net income because we follow mark-to-market accounting and recognize all gains and losses on such instruments in earnings in the period in which they occur. For the year ended December 31, 2011, we reported a $55.8 million non-cash mark-to-market loss on commodity derivative instruments.

We compare our estimates of the fair values of our commodity and interest rate derivative instruments with those provided by our counterparties. There have been no significant differences.

Recent Accounting Pronouncements

In December 2011, the FASB issued amendments to enhance disclosures required by GAAP by requiring improved information about financial instruments and derivative instruments that are either (i) offset in accordance with the current definition of right of setoff or the current balance sheet netting for derivative instruments allowed under current GAAP or (ii) subject to an enforceable master netting arrangement or similar agreement, irrespective of whether they are offset in accordance with either the definition of right of setoff or the current balance sheet netting for derivative instruments. This information will enable users of an entity s financial statements to evaluate the effect or potential effect of netting arrangements on an entity s financial position, including the effect or potential effect of rights of setoff associated with certain financial instruments and derivative instruments in the scope of the update.

An entity is required to apply the amendments for annual reporting periods beginning on or after January 1, 2013, and interim periods within those annual periods. An entity should provide the disclosures required by those amendments retrospectively for all comparative periods presented. We plan to adopt on January 1, 2013 and do not expect this update to have a significant impact on our consolidated financial statements.

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Item 7A. Quantitative and Qualitative Disclosure About Market Risk

We are exposed to a variety of market risks including credit risk, commodity price risk and interest rate risk. We address these risks through a program of risk management which includes the use of derivative instruments. The following quantitative and qualitative information is provided about financial instruments to which we are a party at December 31, 2011, and from which we may incur future gains or losses from changes in market interest rates or commodity prices and losses from extension of credit. We do not enter into derivative or other financial instruments for speculative or trading purposes.

Hypothetical changes in interest rates and commodity prices chosen for the following estimated sensitivity analysis are considered to be reasonably possible near-term changes generally based on consideration of past fluctuations for each risk category. However, since it is not possible to accurately predict future changes in interest rates and commodity prices, these hypothetical changes may not necessarily be an indicator of probable future fluctuations.

Credit risk. We monitor our risk of loss due to non-performance by counterparties of their contractual obligations. Our principal exposure to credit risk is through the sale of our oil and natural gas production, which we market to energy marketing companies and refineries and to a lesser extent our derivative counterparties. We monitor our exposure to these counterparties primarily by reviewing credit ratings, financial statements and payment history. We extend credit terms based on our evaluation of each counterparty s creditworthiness. Although we have not generally required our counterparties to provide collateral to support their obligation to us, we may, if circumstances dictate, require collateral in the future. In this manner, we reduce credit risk.

We have entered into International Swap Dealers Association Master Agreements (ISDA Agreements) with each of our derivative counterparties. The terms of the ISDA Agreements provide us and the counterparties with rights of set off upon the occurrence of defined acts of default by either us or a counterparty to a derivative, whereby the party not in default may set off all derivative liabilities owed to the defaulting party against all derivative asset receivables from the defaulting party. See Note I of the Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data for additional information regarding our derivative activities.

We are closely monitoring the European debt crisis which could negatively impact the U.S. debt markets. If further deterioration occurs it could impair our ability to raise debt, access our credit facility and collect hedging proceeds from our derivative counterparties.

Commodity price risk. We are exposed to market risk as the prices of oil and natural gas are subject to fluctuations resulting from changes in supply and demand. To reduce our exposure to changes in the prices of oil and natural gas we have entered into, and may in the future enter into additional commodity price risk management arrangements for a portion of our oil and natural gas production. The agreements that we have entered into generally have the effect of providing us with a fixed price for a portion of our expected future oil and natural gas production over a fixed period of time. Our commodity price risk management activities could have the effect of reducing net income and the value of our securities. An average increase in the commodity price of $10.00 per barrel of oil and $1.00 per MMBtu for natural gas from the commodity prices at December 31, 2011, would have increased the net unrealized loss on our commodity price risk management contracts by approximately $210.6 million.

At December 31, 2011, we had (i) oil price swaps that settle on a monthly basis covering future oil production from January 1, 2012 through December 31, 2016 and (ii) natural gas price swaps, natural gas price collars and natural gas basis swaps covering future natural gas production from January 1, 2012 to December 31, 2012, see Note I of the Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data for additional information on the commodity derivative instruments. The average NYMEX oil price and average NYMEX natural gas prices for the year ended December 31, 2011, was $95.07 per Bbl and

$4.03 per MMBtu, respectively. At February 21, 2012, the NYMEX oil price and NYMEX natural gas price were $105.84 per Bbl and $2.63 per MMBtu, respectively. A decrease in the average NYMEX oil and natural gas prices below those at December 31, 2011, would decrease the fair value liability of our commodity derivative contracts from their recorded balance at December 31, 2011. Changes in the recorded fair value of the undesignated commodity derivative contracts are marked to market through earnings as unrealized gains or losses. The potential decrease in our fair value liability would be recorded in earnings as an unrealized gain. However, an increase in the average NYMEX oil and natural gas prices above those at December 31, 2011, would increase the fair value liability of our commodity derivative contracts from their recorded balance at December 31, 2011. The potential increase in our fair value liability would be recorded in earnings as an unrealized loss. We are currently unable to estimate the effects on the earnings of future periods resulting from changes in the market value of our commodity derivative contracts.

Interest rate risk. Our exposure to changes in interest rates relates primarily to debt obligations. We manage our interest rate exposure by limiting our variable-rate debt to a certain percentage of total capitalization and by monitoring the effects of market changes in interest rates. To reduce our exposure to changes in interest rates we have entered into, and may in the future enter into additional interest rate risk management arrangements for a portion of our outstanding debt. The agreements that we have entered into generally have the effect of providing us with a fixed interest rate for a portion of our variable rate debt. We may utilize interest rate derivatives to alter interest rate exposure in an attempt to reduce interest rate expense related to existing debt issues. Interest rate derivatives are used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio. We are exposed to changes in interest rates as a result of our credit facility, and the terms of our credit facility require us to pay higher interest rate margins as we utilize a larger percentage of our available commitments.

We had total indebtedness of $583.5 million outstanding under our credit facility at December 31, 2011. The impact of a 1 percent increase in interest rates on this amount of debt would result in increased annual interest expense of approximately $5.8 million.

The fair value of our derivative instruments is determined based on our valuation models. We did not change our valuation method during 2011. During 2011, we were party to commodity and interest rate derivative instruments. See Note I of the Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data for additional information regarding our derivative instruments. The following table reconciles the changes that occurred in the fair values of our derivative instruments during the year ended December 31, 2011:

	Derivative Instruments Net Assets (Liabilities) [a]		
(in thousands)	**Commodities**	**Interest Rate** [b]	**Total**
Fair value of contracts outstanding at December 31, 2010	$ (134,580)	$ (5,754)	$ (140,334)
Changes in fair values [c]	(22,480)	(870)	(23,350)
Contract maturities	78,230	6,624	84,854
Fair value of contracts outstanding at December 31, 2011	$ (78,830)	$ -	$ (78,830)

(a) Represents the fair values of open derivative contracts subject to market risk.
(b) We terminated our interest rate swaps in May 2011.
(c) New derivative contracts entered into by us have no intrinsic value at inception.

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Item 8. Financial Statements and Supplementary Data

Our consolidated financial statements and supplementary financial data are included in this report beginning on page F-1.

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

We had no changes in, and no disagreements with, our accountants on accounting and financial disclosure.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures. As required by Rule 13a-15(b) of the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this report. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon the evaluation, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures were effective at December 31, 2011 at the reasonable assurance level.

Changes in Internal Control over Financial Reporting. There have been no changes in our internal controls over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that occurred during our last fiscal quarter that have materially affected or are reasonably likely to materially affect our internal controls over financial reporting.

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MANAGEMENT S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting. The Company s internal control over financial reporting is a process designed under the supervision of the Company s Chief Executive Officer and Chief Financial Officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company s financial statements for external purposes in accordance with generally accepted accounting principles.

As of December 31, 2011, management assessed the effectiveness of the Company s internal control over financial reporting based on the criteria for effective internal control over financial reporting established in Internal Control - Integrated Framework, issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our assessment and those criteria, management determined that the Company maintained effective internal control over financial reporting at December 31, 2011.

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.

Grant Thornton LLP, the independent registered public accounting firm that audited the consolidated financial statements of the Company included in this annual report on Form 10-K, has issued their report on the effectiveness of the Company s internal control over financial reporting at December 31, 2011. The report, which expresses an unqualified opinion on the effectiveness of the Company s internal control over financial reporting at December 31, 2011, is included in this Item under the heading Report of Independent Registered Public Accounting Firm.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders

Concho Resources Inc.

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

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

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

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

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

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Concho Resources Inc. and subsidiaries as of December 31, 2011 and 2010 and the related consolidated statements of operations, stockholders equity and cash flows for each of the three years in the period ended December 31, 2011, and our report dated February 24, 2012 expressed an unqualified opinion thereon.

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma

February 24, 2012

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Item 9B. Other Information

None.

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PART III

Item 10. Directors, Executive Officers and Corporate Governance

Item 10 will be incorporated by reference pursuant to Regulation 14A under the Exchange Act. We expect to file a definitive proxy statement with the SEC within 120 days after the close of the year ended December 31, 2011.

Item 11. Executive Compensation

Item 11 will be incorporated by reference pursuant to Regulation 14A under the Exchange Act. We expect to file a definitive proxy statement with the SEC within 120 days after the close of the year ended December 31, 2011.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Equity Compensation Plans

At December 31, 2011, a total of 5,850,000 shares of common stock were authorized for issuance under our equity compensation plan. In the table below, we describe certain information about these shares and the equity compensation plan which provides for their authorization and issuance. You can find descriptions of our stock incentive plan under Note G of the Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data.

Plan category	(1) Number of securities to be issued upon exercise of outstanding options	(2) Weighted average exercise price of outstanding options	(3) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (1))
Equity compensation plan approved by security holders[(a)]	930,178	$ 18.10	872,014
Equity compensation plan not approved by security holders[(b)]	-	$ -	-
Total	930,178		872,014

(a) 2006 Stock Incentive Plan. See Note G of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data."

(b) None.

The remaining information required by Item 12 will be incorporated by reference pursuant to Regulation 14A under the Exchange Act. We expect to file a definitive proxy statement with the SEC within 120 days after the close of the year ended December 31, 2011.

Item 13. Certain Relationships and Related Transactions, and Director Independence

Item 13 will be incorporated by reference pursuant to Regulation 14A under the Exchange Act. We expect to file a definitive proxy statement with the SEC within 120 days after the close of the year ended December 31, 2011.

Item 14. Principal Accounting Fees and Services

Item 14 will be incorporated by reference pursuant to Regulation 14A under the Exchange Act. We expect to file a definitive proxy statement with the SEC within 120 days after the close of the year ended December 31, 2011.

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PART IV

Item 15. Exhibits, Financial Statement Schedules, and Reports on Form 8-K

(a) Listing of Financial Statements

Financial Statements

The following consolidated financial statements of ours are included in Financial Statements and Supplementary Data:

Report of Independent Registered Public Accounting Firm

Consolidated Balance Sheets as of December 31, 2011 and 2010

Consolidated Statements of Operations for the Years Ended December 31, 2011, 2010 and 2009

Consolidated Statements of Stockholders Equity for the Years Ended December 31, 2011, 2010 and 2009

Consolidated Statements of Cash Flows for the Years Ended December 31, 2011, 2010 and 2009

Notes to Consolidated Financial Statements

Unaudited Supplementary Information

(b) Exhibits

The exhibits to this report required to be filed pursuant to Item 15(b) are listed below and in the Index to Exhibits attached hereto.

(c) Financial Statement Schedules

No financial statement schedules are required to be filed as part of this report or they are inapplicable.

Exhibits

Exhibit Number	Exhibit
2.1	Asset Purchase Agreement, dated July 19, 2010, by and among Concho Resources Inc., Marbob Energy Corporation, Pitch Energy Corporation, Costaplenty Energy Corporation and John R. Gray, LLC (filed as Exhibit 2.1 to the Company s Current Report on Form 8-K on July 20, 2010, and incorporated herein by reference).
3.1	Restated Certificate of Incorporation (filed as Exhibit 3.1 to the Company s Current Report on Form 8-K on August 6, 2007, and incorporated herein by reference).
3.2	Amended and Restated Bylaws of Concho Resources Inc., as amended March 25, 2008 (filed as Exhibit 3.1 to the Company s Current Report on Form 8-K on March 26, 2008, and incorporated herein by reference).
4.1	Specimen Common Stock Certificate (filed as Exhibit 4.1 to the Company s Registration Statement on Form S-1/A on July 5, 2007, and incorporated herein by reference).
4.2	Indenture, dated September 18, 2009, between Concho Resources Inc., the subsidiary guarantors named therein, and Wells Fargo Bank, National Association, as trustee (filed as Exhibit 4.1 to the Company s Current Report on Form 8-K on September 22, 2009, and incorporated herein by reference).

4.3	First Supplemental Indenture, dated September 18, 2009, between Concho Resources Inc., the subsidiary guarantors named therein, and Wells Fargo Bank, National Association, as trustee (filed as Exhibit 4.2 to the Company s Current Report on Form 8-K on September 22, 2009, and incorporated herein by reference).

Exhibit Number		Exhibit
4.4		Second Supplemental Indenture, dated November 3, 2010, between Concho Resources Inc., the subsidiary guarantors named therein, and Wells Fargo Bank, National Association, as trustee (filed as Exhibit 4.4 to the Post-Effective Amendment to the Company s Registration Statement on Form S-3 on December 7, 2010, and incorporated herein by reference).
4.5		Third Supplemental Indenture, dated December 14, 2010, between Concho Resources Inc., the subsidiary guarantors named therein, and Wells Fargo Bank, National Association, as trustee (filed as Exhibit 4.1 to the Company s Current Report on Form 8-K on December 14, 2010, and incorporated herein by reference).
4.6		Fourth Supplemental Indenture, dated May 23, 2011, between Concho Resources Inc., the subsidiary guarantors named therein, and Wells Fargo Bank, National Association, as trustee (filed as Exhibit 4.1 to the Company s Current Report on Form 8-K on May 23, 2011, and incorporated herein by reference).
4.7	(a)	Fifth Supplemental Indenture, dated December 12, 2011, between Concho Resources Inc., the subsidiary guarantors named therein, and Wells Fargo Bank, National Association, as trustee.
4.8		Form of 8.625% Senior Notes due 2017 (included in Exhibit 4.2 to the Company s Current Report on Form 8-K on September 22, 2009, and incorporated herein by reference).
4.9		Form of 7.0% Senior Notes due 2021 (included in Exhibit 4.1 to the Company s Current Report on Form 8-K on December 14, 2010, and incorporated herein by reference).
4.10		Form of 6.5% Senior Notes due 2022 (included in Exhibit 4.1 to the Company s Current Report on Form 8-K on May 23, 2011, and incorporated herein by reference).
10.1		Registration Rights Agreement dated February 27, 2006, among Concho Resources Inc. and the other signatories thereto (filed as Exhibit 10.12 to the Company s Registration Statement on Form S-1 on April 24, 2007, and incorporated herein by reference).
10.2	**	Concho Resources Inc. 2006 Stock Incentive Plan (filed as Exhibit 10.13 to the Company s Registration Statement on Form S-1 on April 24, 2007, and incorporated herein by reference).
10.3	**	Form of Nonstatutory Stock Option Agreement (filed as Exhibit 10.16 to the Company s Annual Report on Form 10-K on March 28, 2008, and incorporated herein by reference).
10.4	**	Form of Restricted Stock Agreement (for employees) (filed as Exhibit 10.16 to the Company s Registration Statement on Form S-1 on April 24, 2007, and incorporated herein by reference).
10.5	**	Form of Restricted Stock Agreement (for non-employee directors) (filed as Exhibit 10.18 to the Company s Annual Report on Form 10-K on March 28, 2008, and incorporated herein by reference).
10.6	**	Employment Agreement dated December 19, 2008, between Concho Resources Inc. and Timothy A. Leach (filed as Exhibit 10.1 to the Company s Current Report on Form 8-K on December 19, 2008, and incorporated herein by reference).
10.7	**	Employment Agreement dated December 19, 2008, between Concho Resources Inc. and E. Joseph Wright (filed as Exhibit 10.3 to the Company s Current Report on Form 8-K on December 19, 2008, and incorporated herein by reference).
10.8	**	Employment Agreement dated December 19, 2008, between Concho Resources Inc. and Darin G. Holderness (filed as Exhibit 10.4 to the Company s Current Report on Form 8-K on December 19, 2008, and incorporated herein by reference).
10.9	**	Employment Agreement dated December 19, 2008, between Concho Resources Inc. and Matthew G. Hyde (filed as Exhibit 10.6 to the Company s Current Report on Form 8-K on December 19, 2008, and incorporated herein by reference).

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Exhibit Number		Exhibit
10.10	**	Employment Agreement dated December 19, 2008, between Concho Resources Inc. and Jack F. Harper (filed as Exhibit 10.7 to the Company s Current Report on Form 8-K on December 19, 2008, and incorporated herein by reference).
10.11	**	Employment Agreement dated November 5, 2009, between Concho Resources Inc. and C. William Giraud (filed as Exhibit 10.18 to the Company s Annual Report on From 10-K on February 26, 2010, and incorporated herein by reference).
10.12	**	Form of First Amendment to Employment Agreement between Concho Resources Inc. and each of Messrs. Leach, Giraud, Harper, Holderness, Hyde and Wright (filed as Exhibit 10.1 to the Company s Quarterly Report on Form 10-Q on May 6, 2011, and incorporated herein by reference).
10.13	**	Form of Indemnification Agreement between Concho Resources Inc. and each of the officers and directors thereof (filed as Exhibit 10.23 to the Company s Registration Statement on Form S-1 on April 24, 2007, and incorporated herein by reference).
10.14	**	Indemnification Agreement, dated February 27, 2008, by and between Concho Resources, Inc. and William H. Easter III (filed as Exhibit 10.1 to the Company s Current Report on Form 8-K on March 4, 2008, and incorporated herein by reference).
10.15	**	Indemnification Agreement, dated May 21, 2008, by and between Concho Resources, Inc. and Matthew G. Hyde (filed as Exhibit 10.1 to the Company s Current Report on Form 8-K on May 28, 2008, and incorporated herein by reference).
10.16	**	Indemnification Agreement, dated August 25, 2008, by and between Concho Resources, Inc. and Darin G. Holderness (filed as Exhibit 10.1 to the Company s Current Report on Form 8-K on August 29, 2008, and incorporated herein by reference).
10.17	**	Indemnification Agreement, dated November 5, 2009, by and between Concho Resources, Inc. and Mark B. Puckett (filed as Exhibit 10.1 to the Company s Current Report on Form 8-K on November 12, 2009, and incorporated herein by reference).
10.18	**	Indemnification Agreement, dated November 5, 2009, by and between Concho Resources, Inc. and C. William Giraud (filed as Exhibit 10.2 to the Company s Current Report on Form 8-K on November 12, 2009, and incorporated herein by reference).
10.19	**	Indemnification Agreement, dated September 24, 2010, between Concho Resources Inc. and Don McCormack (filed as Exhibit 10.1 to the Company s Current Report on Form 8-K on September 29, 2010, and incorporated herein by reference).
10.20	**	Indemnification Agreement, dated January 10, 2012, between Concho Resources Inc. and Gary A. Merriman (filed as exhibit 10.1 to the Company s Current Report on Form 8-K on January 12, 2012, and incorporated herein by reference).
10.21	**	Consulting Agreement dated June 9, 2009, by and between Concho Resources Inc. and Steven L. Beal (filed as Exhibit 10.1 to the Company s Current Report on Form 8-K on June 12, 2009, and incorporated herein by reference).
10.22		Amended and Restated Credit Agreement, dated July 31, 2008, by and among Concho Resources Inc., JP Morgan Chase Bank, N.A., Bank of America, N.A., Calyon New York Branch, ING Capital LLC and BNP Paribas and certain other lenders party thereto (filed as Exhibit 10.2 to the Company s Current Report on Form 8-K on August 6, 2008, and incorporated herein by reference).

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Exhibit Number		Exhibit
10.23		First Amendment to Amended and Restated Credit Agreement dated as of April 7, 2009, to the Amended and Restated Credit Agreement, dated July 31, 2008, by and among Concho Resources Inc., JP Morgan Chase Bank, N.A., Bank of America, N.A., Calyon New York Branch, ING Capital LLC and BNP Paribas and certain other lenders party thereto (filed as Exhibit 4.1 to the Company s Current Report on Form 8-K on April 9, 2009, and incorporated herein by reference).
10.24		Limited Consent and Waiver, dated September 4, 2009, to the Amended and Restated Credit Agreement dated July 31, 2008, by and among Concho Resources Inc., JP Morgan Chase Bank, N.A., Bank of America, N.A., Calyon New York Branch, ING Capital LLC and BNP Paribas and certain other lenders party thereto (filed as Exhibit 10.1 to the Company s Current Report on Form 8-K on September 22, 2009, and incorporated herein by reference).
10.25		Second Amendment to Amended and Restated Credit Agreement, dated April 26, 2010, by and among Concho Resources Inc., JP Morgan Chase Bank, N.A., as Administrative Agent (filed as Exhibit 4.1 to the Company s Current Report on Form 8-K on April 29, 2010, and incorporated herein by reference).
10.26		Third Amendment to Amended and Restated Credit Agreement and Limited Waiver, dated June 16, 2010, among Concho Resources Inc. and the lenders party thereto and JPMorgan Chase Bank, N.A., as Administrative Agent (filed as Exhibit 10.1 to the Company s Current Report on Form 8-K on June 18, 2010, and incorporated herein by reference).
10.27		Fourth Amendment to Amended and Restated Credit Agreement, dated October 7, 2010, among Concho Resources Inc. and the lenders party thereto and JP Morgan Chase Bank, N.A., as Administrative Agent (filed as Exhibit 10.2 to the Company s Current Report on Form 8-K on October 13, 2010, and incorporated herein by reference).
10.28		Fifth Amendment to Amended and Restated Credit Agreement and Limited Waiver, dated as of December 7, 2010, among Concho Resources Inc. and the lenders party thereto and JPMorgan Chase Bank, N.A., as administrative agent (filed as Exhibit 10.1 to the Company s Current Report on Form 8-K on December 10, 2010, and incorporated herein by reference).
10.29		Sixth Amendment to Amended and Restated Credit Agreement, dated as of April 25, 2011, among Concho Resources Inc. and the lenders party thereto and JPMorgan Chase Bank, N.A., as administrative agent (filed as Exhibit 10.1 to the Company s Current Report on Form 8-K on April 27, 2011, and incorporated herein by reference).
10.30		Seventh Amendment to Amended and Restated Credit Agreement, dated as of October 12, 2011, among Concho Resources Inc., the lenders party thereto and JPMorgan Chase Bank, N.A., as administrative agent (filed as Exhibit 10.1 to the Company s Current Report on Form 8-K on October 14, 2011, and incorporated herein by reference).
10.31		Common Stock Purchase Agreement, dated July 19, 2010, by and among Concho Resources Inc. and the purchasers named therein (filed as Exhibit 10.1 to the Company s Current Report on Form 8-K on July 20, 2010, and incorporated herein by reference).
10.32		Promissory Note in the principal amount of $150,000,000 between Concho Resources Inc. and Pitch Energy Corporation, dated October 7, 2010 (filed as Exhibit 10.5 to the Company s Quarterly Report on Form 10-Q on November 4, 2010, and incorporated herein by reference).
10.33		Registration Rights Agreement, dated October 7, 2010, by and between Concho Resources Inc. and the purchasers named therein (filed as Exhibit 10.1 to the Company s Current Report on Form 8-K on October 13, 2010, and incorporated herein by reference).
10.34	**	Form of Restricted Stock Agreement (for officers) (filed as Exhibit 10.35 to the Company s Annual Report on Form 10-K on February 25, 2011, and incorporated herein by reference).

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Exhibit Number		Exhibit
10.35	**	Form of Restricted Stock Agreement (for non-officer employees) (filed as Exhibit 10.36 to the Company s Annual Report on Form 10-K on February 25, 2011, and incorporated herein by reference).
12.1	(a)	Ratio of Earnings to Fixed Charges and Ratio of Earnings to Fixed Charges and Preferred Stock Dividends.
21.1	(a)	Subsidiaries of Concho Resources Inc.
23.1	(a)	Consent of Grant Thornton LLP.
23.2	(a)	Consent of Netherland, Sewell & Associates, Inc.
23.3	(a)	Netherland, Sewell & Associates, Inc. Reserve Report.
23.4	(a)	Consent of Cawley, Gillespie & Associates, Inc.
23.5	(a)	Cawley, Gillespie & Associates, Inc. Reserve Report.
31.1	(a)	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	(a)	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	(b)	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	(b)	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS	(a)	XBRL Instance Document.
101.SCH	(a)	XBRL Schema Document.
101.CAL	(a)	XBRL Calculation Linkbase Document.
101.DEF	(a)	XBRL Definition Linkbase Document.
101.LAB	(a)	XBRL Labels Linkbase Document.
101.PRE	(a)	XBRL Presentation Linkbase Document.

(a) Filed herewith.
(b) Furnished herewith.
** Management contract or compensatory plan or arrangement.

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GLOSSARY OF TERMS

The following terms are used throughout this report:

Bbl	One stock tank barrel, of 42 United States gallons liquid volume, used herein in reference to oil, condensate or natural gas liquids.
Boe	One barrel of oil equivalent, a standard convention used to express oil and natural gas volumes on a comparable oil equivalent basis. Natural gas equivalents are determined under the relative energy content method by using the ratio of 6.0 Mcf of natural gas to 1.0 Bbl of oil or condensate.
Basin	A large natural depression on the earth s surface in which sediments accumulate.
Development wells	Wells drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.
Dry hole	A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production would exceed production expenses, taxes and the royalty burden.
Exploratory wells	Wells drilled to find and produce oil or natural gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir, or to extend a known reservoir.
Field	An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.
GAAP	Generally accepted accounting principles in the United States of America.
Gross wells	The number of wells in which a working interest is owned.
Horizontal drilling	A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a high angle to vertical (which can be greater than 90 degrees) in order to stay within a specified interval.
Infill drilling	Drilling into the same pool as known producing wells so that oil or natural gas does not have to travel as far through the formation.

LIBOR	London Interbank Offered Rate, which is a market rate of interest.
MBbl	One thousand barrels of oil, condensate or natural gas liquids.
MBoe	One thousand Boe.
Mcf	One thousand cubic feet of natural gas.
MMBoe	One million Boe.

GLOSSARY OF TERMS continued

MMBtu	One million British thermal units.
MMcf	One million cubic feet of natural gas.
NYMEX	The New York Mercantile Exchange.
NYSE	The New York Stock Exchange.
Net acres	The percentage of total acres an owner owns out of a particular number of acres within a specified tract. For example, an owner who has a 50 percent interest in 100 acres owns 50 net acres.
Net wells	The total of fractional working interests owned in gross wells.
PV-10	When used with respect to oil and natural gas reserves, PV-10 means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development and abandonment costs, using prices and costs in effect at the determination date, before income taxes, and without giving effect to non-property-related expenses except for specific general and administrative expenses incurred to operate the properties, discounted to a present value using an annual discount rate of 10 percent. PV-10 is a non-GAAP financial measure.
Productive wells	Wells that produce commercial quantities of hydrocarbons, exclusive of their capacity to produce at a reasonable rate of return.
Proved developed reserves	Has the meaning given to such term in SEC Release No. 33-8995: *Modernization of Oil and Gas Reporting*, which defines proved reserves as:

Proved developed reserves are reserves of any category that can be expected to be recovered:

(i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) through installed extraction equipment and infrastructure operational at the time of the reserve estimate if the extraction is by means not involving a well.

Supplemental definitions from the 2007 Petroleum Resources Management System:

Proved Developed Producing Reserves Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.

GLOSSARY OF TERMS continued

Proved Developed Non-Producing Reserves Developed Non-Producing Reserves include shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future recompletion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

Proved reserves Has the meaning given to such term in SEC Release No. 33-8995: *Modernization of Oil and Gas Reporting*, which defines proved reserves as:

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

(i) The area of the reservoir considered as proved includes:

(A) the area identified by drilling and limited by fluid contacts, if any, and

(B) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or natural gas on the basis of available geoscience and engineering data.

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

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

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GLOSSARY OF TERMS continued

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) the project has been approved for development by all necessary parties and entities, including governmental entities.

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

Proved undeveloped reserves

Has the meaning given to such term in SEC Release No. 33-8995: *Modernization of Oil and Gas Reporting*, which defines proved reserves as:

Proved undeveloped oil and natural gas reserves are reserves of any category 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.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

Recompletion

The addition of production from another interval or formation in an existing wellbore.

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GLOSSARY OF TERMS continued

Reservoir	A formation beneath the surface of the earth from which hydrocarbons may be present. Its make-up is sufficiently homogenous to differentiate it from other formations.
Spacing	The distance between wells producing from the same reservoir. Spacing is expressed in terms of acres, e.g., 40-acre spacing, and is established by regulatory agencies.
Standardized measure	The present value (discounted at an annual rate of 10 percent) of estimated future net revenues to be generated from the production of proved reserves net of estimated income taxes associated with such net revenues, as determined in accordance with FASB guidelines, without giving effect to non-property related expenses such as indirect general and administrative expenses, and debt service or to depreciation, depletion and amortization. Standardized measure does not give effect to derivative transactions.
Undeveloped acreage	Acreage owned or leased on which wells can be 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.
Wellbore	The hole drilled by the bit that is equipped for oil or natural gas production on a completed well. Also called a well or borehole.
Working interest	The right granted to the lessee of a property to explore for and to produce and own oil, natural gas, or other minerals. The working interest owners bear the exploration, development, and operating costs on either a cash, penalty, or carried basis.
Workover	Operations on a producing well to restore or increase production.

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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.

CONCHO RESOURCES INC.

Date: February 24, 2012

By /s/ Timothy A. Leach

Timothy A. Leach
Director, Chairman of the Board of Directors, Chief Executive Officer and President (Principal Executive Officer)

Pursuant to the requirements 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.

Signature	Title	Date
/s/ TIMOTHY A. LEACH Timothy A. Leach	Director, Chairman of the Board of Directors, Chief Executive Officer and President (Principal Executive Officer)	February 24, 2012
/s/ DARIN G. HOLDERNESS Darin G. Holderness	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)	February 24, 2012
/s/ DON O. McCORMACK Don O. McCormack	Vice President and Chief Accounting Officer (Principal Accounting Officer)	February 24, 2012
/s/ STEVEN L. BEAL Steven L. Beal	Director	February 24, 2012
/s/ TUCKER S. BRIDWELL Tucker S. Bridwell	Director	February 24, 2012
/s/ WILLIAM H. EASTER III William H. Easter III	Director	February 24, 2012
/s/ W. HOWARD KEENAN, JR. W. Howard Keenan, Jr.	Director	February 24, 2012
/s/ GARY A. MERRIMAN Gary A. Merriman	Director	February 24, 2012
/s/ RAY M. POAGE Ray M. Poage	Director	February 24, 2012
/s/ MARK B. PUCKETT Mark B. Puckett	Director	February 24, 2012
/s/ A. WELLFORD TABOR A. Wellford Tabor	Director	February 24, 2012

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders

Concho Resources Inc.

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

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

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

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company s internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) and our report dated February 24, 2012, expressed an unqualified opinion thereon.

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma

February 24, 2012

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Concho Resources Inc.

Consolidated Balance Sheets

(in thousands, except share and per share amounts)	December 31, 2011	2010
Assets		
Current assets:		
Cash and cash equivalents	$ 342	$ 384
Accounts receivable, net of allowance for doubtful accounts:		
Oil and natural gas	213,921	136,471
Joint operations and other	153,746	131,966
Related parties	-	115
Derivative instruments	1,698	6,855
Deferred income taxes	28,793	42,716
Prepaid costs and other	12,523	12,126
Total current assets	411,023	330,633
Property and equipment:		
Oil and natural gas properties, successful efforts method	7,347,460	5,616,249
Accumulated depletion and depreciation	(1,116,545)	(730,509)
Total oil and natural gas properties, net	6,230,915	4,885,740
Other property and equipment, net	59,203	28,047
Total property and equipment, net	6,290,118	4,913,787
Funds held in escrow	17,394	-
Deferred loan costs, net	65,641	52,828
Intangible asset - operating rights, net	33,425	34,973
Inventory	19,419	28,342
Noncurrent derivative instruments	7,944	2,233
Other assets	4,612	5,698
Total assets	$ 6,849,576	$ 5,368,494
Liabilities and Stockholders Equity		
Current liabilities:		
Accounts payable:		
Trade	$ 23,198	$ 39,951
Related parties	154	1,189
Bank overdrafts	39,241	12,314
Revenue payable	146,061	57,406
Accrued and prepaid drilling costs	293,919	215,079
Derivative instruments	56,218	97,775
Other current liabilities	142,686	83,275
Total current liabilities	701,477	506,989

Long-term debt	2,080,141	1,668,521
Deferred income taxes	1,002,295	720,889
Noncurrent derivative instruments	32,254	51,647
Asset retirement obligations and other long-term liabilities	52,670	36,574
Commitments and contingencies (Note K)		
Stockholders equity:		
Common stock, $0.001 par value; 300,000,000 authorized; 103,756,222 and 102,842,082 shares issued at December 31, 2011 and 2010, respectively	104	103
Additional paid-in capital	1,925,757	1,874,649
Retained earnings	1,058,874	510,737
Treasury stock, at cost; 55,990 and 31,963 shares at December 31, 2011 and 2010, respectively	(3,996)	(1,615)
Total stockholders equity	2,980,739	2,383,874
Total liabilities and stockholders equity	$ 6,849,576	$ 5,368,494

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

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Concho Resources Inc.

Consolidated Statements of Operations

	Years Ended December 31,		
(in thousands, except per share amounts)	**2011**	**2010**	**2009**
Operating revenues:			
Oil sales	$ 1,330,601	$ 735,333	$ 399,491
Natural gas sales	409,366	204,934	111,276
Total operating revenues	1,739,967	940,267	510,767
Operating costs and expenses:			
Oil and natural gas production	308,011	166,409	97,667
Exploration and abandonments	11,779	10,324	10,632
Depreciation, depletion and amortization	428,377	241,642	191,889
Accretion of discount on asset retirement obligations	2,965	1,482	909
Impairments of long-lived assets	439	11,614	7,880
General and administrative (including non-cash stock-based compensation of $19,271, $12,931 and $9,040 for the years ended December 31, 2011, 2010 and 2009, respectively)	96,261	64,275	53,163
Bad debt expense	-	870	(1,035)
Loss on derivatives not designated as hedges	23,350	87,325	156,857
Total operating costs and expenses	871,182	583,941	517,962
Income (loss) from operations	868,785	356,326	(7,195)
Other income (expense):			
Interest expense	(118,360)	(60,087)	(28,292)
Other, net	(3,974)	(10,313)	(414)
Total other expense	(122,334)	(70,400)	(28,706)
Income (loss) from continuing operations before income taxes	746,451	285,926	(35,901)
Income tax benefit (expense)	(285,848)	(115,278)	22,589
Income (loss) from continuing operations	460,603	170,648	(13,312)
Income from discontinued operations, net of tax	87,534	33,722	3,510
Net income (loss)	$ 548,137	$ 204,370	$ (9,802)
Basic earnings per share:			
Income (loss) from continuing operations	$ 4.49	$ 1.84	$ (0.16)
Income from discontinued operations, net of tax	0.85	0.37	0.04

Net income (loss)	$ 5.34	$ 2.21	$ (0.12)
Weighted average shares used in basic earnings per share	102,581	92,542	84,912
Diluted earnings per share:			
Income (loss) from continuing operations	$ 4.44	$ 1.82	$ (0.16)
Income from discontinued operations, net of tax	0.84	0.36	0.04
Net income (loss)	$ 5.28	$ 2.18	$ (0.12)
Weighted average shares used in diluted earnings per share	103,653	93,837	84,912

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

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Concho Resources Inc.

Consolidated Statements of Stockholders Equity

	Common Stock				Treasury Stock		
(in thousands)	Shares	Amount	Additional Paid-in Capital	Retained Earnings	Shares	Amount	Total Stockholders Equity
BALANCE AT DECEMBER 31, 2008	84,829	$ 85	$ 1,009,025	$ 316,169	3	$ (125)	$ 1,325,154
Net loss	-	-	-	(9,802)	-	-	(9,802)
Stock options exercised	695	1	6,115	-	-	-	6,116
Grants of restricted stock	300	-	-	-	-	-	-
Stock-based compensation	-	-	9,040	-	-	-	9,040
Cancellation of restricted stock	(8)	-	-	-	-	-	-
Excess tax benefits related to stock-based compensation	-	-	5,212	-	-	-	5,212
Purchase of treasury stock	-	-	-	-	9	(292)	(292)
BALANCE AT DECEMBER 31, 2009	85,816	86	1,029,392	306,367	12	(417)	1,335,428
Net income	-	-	-	204,370	-	-	204,370
Issuance of common stock	14,845	15	739,431	-	-	-	739,446
Common stock issued in acquisition	1,104	1	75,772	-	-	-	75,773
Stock options exercised	560	1	5,777	-	-	-	5,778
Grants of restricted stock	537	-	-	-	-	-	-
Stock-based compensation	-	-	12,931	-	-	-	12,931
Cancellation of restricted stock	(20)	-	-	-	-	-	-
Excess tax benefits related to stock-based compensation	-	-	11,346	-	-	-	11,346
Purchase of treasury stock	-	-	-	-	20	(1,198)	(1,198)
BALANCE AT DECEMBER 31, 2010	102,842	103	1,874,649	510,737	32	(1,615)	2,383,874
Net income	-	-	-	548,137	-	-	548,137
Stock options exercised	667	1	7,800	-	-	-	7,801
Grants of restricted stock	307	-	-	-	-	-	-
Stock-based compensation	-	-	19,271	-	-	-	19,271
Cancellation of restricted stock	(60)	-	-	-	-	-	-
Excess tax benefits related to stock-based compensation	-	-	24,037	-	-	-	24,037
Purchase of treasury stock	-	-	-	-	24	(2,381)	(2,381)
BALANCE AT DECEMBER 31, 2011	103,756	$ 104	$ 1,925,757	$ 1,058,874	56	$ (3,996)	$ 2,980,739

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

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Concho Resources Inc.

Consolidated Statements of Cash Flows

	Years Ended December 31,		
(in thousands)	2011	2010	2009
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ 548,137	$ 204,370	$ (9,802)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	428,377	241,642	191,889
Accretion of discount on asset retirement obligations	2,965	1,482	909
Impairments of long-lived assets	439	11,614	7,880
Exploration and abandonments, including dry holes	6,802	7,612	6,997
Non-cash compensation expense	19,271	12,931	9,040
Bad debt expense	-	870	(1,035)
Deferred income taxes	261,686	100,337	(34,448)
Loss on sale of assets, net	1,139	58	114
Loss on derivatives not designated as hedges	23,350	87,325	156,857
Discontinued operations	(76,148)	5,665	22,249
Other non-cash items	3,075	6,837	3,870
Changes in operating assets and liabilities, net of acquisitions:			
Accounts receivable	(117,561)	(92,957)	(26,217)
Prepaid costs and other	(1,730)	3,255	(7,952)
Inventory	7,749	(2,321)	4,117
Accounts payable	(25,381)	24,373	7,960
Revenue payable	84,850	26,337	8,118
Other current liabilities	32,438	12,152	19,000
Net cash provided by operating activities	1,199,458	651,582	359,546
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures on oil and natural gas properties	(1,707,939)	(2,127,047)	(669,267)
Additions to other property and equipment	(37,651)	(6,935)	(4,396)
Proceeds from the sale of assets	196,420	104,349	5,099
Funds held in escrow	(17,394)	-	-
Settlements received from (paid on) derivatives not designated as hedges	(84,854)	(13,824)	82,416
Net cash used in investing activities	(1,651,418)	(2,043,457)	(586,148)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from issuance of debt	2,809,300	2,946,748	1,158,650
Payments of debt	(2,389,300)	(2,283,248)	(942,916)
Exercise of stock options	7,801	5,778	6,116
Excess tax benefit from stock-based compensation	24,037	11,346	5,212
Net proceeds from issuance of common stock	-	739,446	-
Payments for loan costs	(24,466)	(38,746)	(8,667)
Purchase of treasury stock	(2,381)	(1,198)	(292)
Bank overdrafts	26,927	8,899	(6,019)
Net cash provided by financing activities	451,918	1,389,025	212,084
Net decrease in cash and cash equivalents	(42)	(2,850)	(14,518)

Cash and cash equivalents at beginning of period		384		3,234		17,752
Cash and cash equivalents at end of period	$	342	$	384	$	3,234
SUPPLEMENTAL CASH FLOWS:						
Cash paid for interest and fees, net of $73, $184 and $66 capitalized interest	$	77,921	$	48,052	$	14,862
Cash paid for income taxes	$	22,768	$	19,885	$	7,299
NON-CASH INVESTING AND FINANCING ACTIVITIES:						
Issuance of common stock for a business combination	$	-	$	75,773	$	-
Issuance of debt for a business combination	$	-	$	159,000	$	-
Deferred tax effect of a business combination	$	-	$	-	$	(835)

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

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2011, 2010 and 2009

Note A. ***Organization and nature of operations***

Concho Resources Inc. (the Company) is a Delaware corporation formed on February 22, 2006. The Company s principal business is the acquisition, development and exploration of oil and natural gas properties primarily located in the Permian Basin region of Southeast New Mexico and West Texas.

Note B. ***Summary of significant accounting policies***

Principles of consolidation. The consolidated financial statements of the Company include the accounts of the Company and its wholly-owned subsidiaries. In addition, a third-party had previously formed an entity to effectuate a tax-free exchange of assets for the Company. The Company had 100 percent control over the decisions of the entity, but had no direct ownership. The third-party conveyed ownership to the Company upon completion of the tax-free exchange process in April 2011, and the entity was subsequently merged into a wholly-owned subsidiary of the Company. It has been consolidated in the Company s financial statements since its formation. All material intercompany balances and transactions have been eliminated.

Discontinued operations. The Company made the following divestitures of assets during the periods covered by these consolidated financial statements:

	Asset Group			
	Permian Basin		Bakken	
(dollars in millions)	Assets		Assets	
Date divested	December 2010		March 2011	
Net proceeds	$	103.3	$	195.9
Gain on sale of assets	$	29.1	$	135.9

As a result, the Company has reflected the results of operations of these divested assets as discontinued operations, rather than as a component of continuing operations. See Note O for additional information regarding these divestitures and their discontinued operations.

Use of estimates in the preparation of financial statements. Preparation of financial statements in conformity with generally accepted accounting principles in the United States of America (U.S. GAAP) requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, 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 periods. Actual results could differ from these estimates. Depletion of oil and natural gas properties are determined using estimates of proved oil and natural gas reserves. There are numerous uncertainties inherent in the estimation of quantities of proved reserves and in the projection of future rates of production and the timing of development expenditures. Similarly, evaluations for impairment of proved and unproved oil and natural gas properties are subject to numerous uncertainties including, among others, estimates of future recoverable reserves and commodity price outlooks. Other significant estimates include, but are not limited to, the asset retirement obligations, fair value of derivative financial instruments, purchase price allocations for business combinations and fair value of stock-based compensation.

Cash equivalents. The Company considers all cash on hand, depository accounts held by banks, money market accounts and investments with an original maturity of three months or less to be cash equivalents. The

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Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2011, 2010 and 2009

Company s cash and cash equivalents are held in a few financial institutions in amounts that exceed the insurance limits of the Federal Deposit Insurance Corporation. However, management believes that the Company s counterparty risks are minimal based on the reputation and history of the institutions selected.

Accounts receivable. The Company sells oil and natural gas to various customers and participates with other parties in the drilling, completion and operation of oil and natural gas wells. Joint interest and oil and natural gas sales receivables related to these operations are generally unsecured. The Company determines joint interest operations accounts receivable allowances based on management s assessment of the creditworthiness of the joint interest owners and the Company s ability to realize the receivables through netting of anticipated future production revenues. Receivables are considered past due if full payment is not received by the contractual due date. Past due accounts are generally written off against the allowance for doubtful accounts only after all collection attempts have been exhausted. The Company had an allowance for doubtful accounts of approximately $0.7 million and $1.3 million at December 31, 2011 and 2010, respectively.

Inventory. Inventory consists primarily of tubular goods and other oilfield goods that the Company plans to utilize in its ongoing exploration and development activities and is carried at the lower of cost or market value, on a weighted average cost basis.

Deferred loan costs. Deferred loan costs are stated at cost, net of amortization, which is computed using the effective interest and straight-line methods. The Company had deferred loan costs of $65.6 million and $52.8 million, net of accumulated amortization of $26.8 million and $15.2 million, at December 31, 2011 and December 31, 2010, respectively.

Future amortization expense of deferred loan costs at December 31, 2011 is as follows:

(in thousands)	**Total**
2012	$ 10,758
2013	10,986
2014	11,232
2015	11,499
2016	6,482
Thereafter	14,684
Total	$ 65,641

Oil and natural gas properties. The Company utilizes the successful efforts method of accounting for its oil and natural gas properties. Under this method all costs associated with productive wells and nonproductive development wells are capitalized, while nonproductive exploration costs are expensed. Capitalized acquisition costs relating to proved properties are depleted using the unit-of-production method based on proved reserves. The depletion of capitalized exploratory drilling and development costs is based on the unit-of-production method using proved developed reserves. During the years ended December 31, 2011, 2010 and 2009, the Company recognized depletion expense from continuing and discontinued operations of $423.2 million, $252.7 million and $201.9 million, respectively.

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The Company generally does not carry the costs of drilling an exploratory well as an asset in its consolidated balance sheets for more than one year following the completion of drilling unless the exploratory well finds oil and natural gas reserves in an area requiring a major capital expenditure and both of the following conditions are met:

(i) the well has found a sufficient quantity of reserves to justify its completion as a producing well; and

(ii) the Company is making sufficient progress assessing the reserves and the economic and operating viability of the project.

Due to the capital intensive nature and the geographical location of certain projects, it may take the Company longer than one year to evaluate the future potential of the exploration well and economics associated with making a determination on its commercial viability. In these instances, the project s feasibility is not contingent upon price improvements or advances in technology, but rather the Company s ongoing efforts and expenditures related to accurately predicting the hydrocarbon recoverability based on well information, gaining access to other companies production, transportation or processing facilities and/or getting partner approval to drill additional appraisal wells. These activities are ongoing and being pursued constantly. Consequently, the Company s assessment of suspended exploratory well costs is continuous until a decision can be made that the well has found proved reserves or is noncommercial and is charged to exploration and abandonments expense. See Note C for additional information regarding the Company s suspended exploratory well costs.

Proceeds from the sales of individual properties and the capitalized costs of individual properties sold or abandoned are credited and charged, respectively, to accumulated depletion. Generally, no gain or loss is recognized until the entire amortization base is sold. However, gain or loss is recognized from the sale of less than an entire amortization base if the disposition is significant enough to materially impact the depletion rate of the remaining properties in the amortization base. Ordinary maintenance and repair costs are expensed as incurred.

Costs of significant nonproducing properties, wells in the process of being drilled and completed and development projects are excluded from depletion until such time as the related project is developed and proved reserves are established or impairment is determined. The Company capitalizes interest, if debt is outstanding, on expenditures for significant development projects until such projects are ready for their intended use. At December 31, 2011 and 2010, the Company had excluded $168.1 million and $127.4 million, respectively, of capitalized costs from depletion, and the Company had capitalized interest of $0.1 million, $0.2 million and $0.1 million, during 2011, 2010 and 2009, respectively.

The Company reviews its long-lived assets to be held and used, including proved oil and natural gas properties, whenever events or circumstances indicate that the carrying value of those assets may not be recoverable. An impairment loss is indicated if the sum of the expected future cash flows is less than the carrying amount of the assets. In this circumstance, the Company recognizes an impairment loss for the amount by which the carrying amount of the asset exceeds the estimated fair value of the asset. The Company reviews its oil and natural gas properties by amortization base or by individual well for those wells not constituting part of an amortization base. For each property determined to be impaired, an impairment loss equal to the difference between the carrying value of the properties and the estimated fair value (discounted future cash flows) of the properties would be recognized at that time. Estimating future cash flows involves the use of judgments, including estimation of the proved and unproved oil and natural gas reserve quantities, timing of development

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and production, expected future commodity prices, capital expenditures and production costs. The Company recognized impairment expense from continuing and discontinued operations of $0.4 million, $15.2 million and $12.2 million during the years ended December 31, 2011, 2010 and 2009, respectively, primarily related to its proved oil and natural gas properties.

Unproved oil and natural gas properties are each periodically assessed for impairment by considering future drilling plans, the results of exploration activities, commodity price outlooks, planned future sales or expiration of all or a portion of such projects. During the years ended December 31, 2011, 2010 and 2009, the Company recognized expense from continuing operations of $5.7 million, $7.6 million and $5.1 million, respectively, related to abandoned prospects, which is included in exploration and abandonments expense in the accompanying consolidated statements of operations.

Other property and equipment. Other capital assets include buildings, vehicles, computer equipment and software, telecommunications equipment, leasehold improvements and furniture and fixtures. These items are recorded at cost, or fair value if acquired, and are depreciated using the straight-line method based on expected lives of the individual assets or group of assets ranging from two to 31 years. During the years ended December 31, 2011, 2010 and 2009, the Company recognized depreciation expense of $5.7 million, $3.1 million and $2.7 million, respectively.

Intangible assets. The Company has capitalized certain operating rights acquired in an acquisition. The gross operating rights of approximately $38.7 million and related accumulated amortization of $5.3 million at December 31, 2011, which have no residual value, are amortized over the estimated economic life of approximately 25 years. Impairment will be assessed if indicators of potential impairment exist or when there is a material change in the remaining useful economic life. Amortization expense for the years ended December 31, 2011, 2010 and 2009 was approximately $1.5 million, $1.5 million and $1.6 million, respectively. The following table reflects the estimated future aggregate amortization expense for each of the periods presented below at December 31, 2011:

(in thousands)		
2012	$	1,549
2013		1,549
2014		1,549
2015		1,549
2016		1,549
Thereafter		25,680
Total	$	33,425

Environmental. The Company is subject to extensive federal, state and local environmental laws and regulations. These laws, which are often changing, regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites. Environmental expenditures are expensed. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefits are expensed. Liabilities for expenditures of a noncapital nature are recorded when environmental assessment and/or remediation is

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probable and the costs can be reasonably estimated. Such liabilities are generally undiscounted unless the timing of cash payments is fixed and readily determinable. At December 31, 2011 and 2010, the Company has accrued approximately $3.5 million and $1.4 million, respectively, related to environmental liabilities. During the years ended December 31, 2011, 2010 and 2009, the Company recognized environmental charges of $9.6 million, $3.0 million and $2.3 million, respectively.

Oil and natural gas sales and imbalances. Oil and natural gas revenues are recorded at the time of delivery of such products to pipelines for the account of the purchaser or at the time of physical transfer of such products to the purchaser. The Company follows the sales method of accounting for oil and natural gas sales, recognizing revenues based on the Company s share of actual proceeds from the oil and natural gas sold to purchasers. Oil and natural gas imbalances are generated on properties for which two or more owners have the right to take production in-kind and, in doing so, take more or less than their respective entitled percentage. Imbalances are tracked by well, but the Company does not record any receivable from or payable to the other owners unless the imbalance has reached a level at which it exceeds the remaining reserves in the respective well. If reserves are insufficient to offset the imbalance and the Company is in an overtake position, a liability is recorded for the amount of shortfall in reserves valued at a contract price or the market price in effect at the time the imbalance is generated. If the Company is in an undertake position, a receivable is recorded for an amount that is reasonably expected to be received, not to exceed the current market value of such imbalance.

The following table reflects the Company s natural gas imbalance positions at December 31, 2011 and 2010 as well as amounts reflected in oil and natural gas production expense for the years ended December 31, 2011, 2010 and 2009:

(dollars in thousands)	December 31, 2011	December 31, 2010
Natural gas imbalance liability (included in asset retirement obligations and other long-term liabilities)	$ 430	$ 403
Overtake position (Mcf)	77,493	71,153
Natural gas imbalance receivable (included in other assets)	$ 100	$ 100
Undertake position (Mcf)	22,210	22,240

	Years Ended December 31, 2011	2010	2009
Value of net overtake (undertake) arising during the year increasing (decreasing) oil and natural gas production expense	$ 27	$ (38)	$ 23
Net overtake (undertake) position arising during the year (Mcf)	6,370	(8,695)	7,317
Value of net (undertake) related to divested assets .	$	$ (252)	$
Net (undertake) position related to divested assets (Mcf)		(54,914)	

Derivative instruments. The Company recognizes all derivative instruments as either assets or liabilities measured at fair value. The Company netted the fair value of derivative instruments by counterparty in the accompanying consolidated balance sheets where the right of offset exists.

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Changes in the fair value of derivative instruments that are fair value hedges are offset against changes in the fair value of the hedged assets, liabilities or firm commitments, through earnings. Effective changes in the fair value of derivative instruments that are cash flow hedges are recognized in accumulated other comprehensive income and reclassified into earnings in the period in which the hedged item affects earnings. Ineffective portions of a derivative instrument s change in fair value are immediately recognized in earnings. Derivative instruments that do not qualify, or cease to qualify, as hedges must be adjusted to fair value, and the adjustments are recorded through earnings. The Company did not have any derivatives designated as fair value or cash flow hedges during the years ended December 31, 2011, 2010, or 2009.

Asset retirement obligations. The Company records the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. Subsequently, the asset retirement cost included in the carrying amount of the related asset is allocated to expense through depletion of the asset. Changes in the liability due to passage of time are generally recognized as an increase in the carrying amount of the liability and as corresponding accretion expense.

Treasury stock. Treasury stock purchases are recorded at cost. Upon reissuance, the cost of treasury shares held is reduced by the average purchase price per share of the aggregate treasury shares held.

General and administrative expense. The Company receives fees for the operation of jointly owned oil and natural gas properties and records such reimbursements as reductions of general and administrative expense. Such fees from continuing and discontinued operations totaled approximately $13.4 million, $14.4 million and $11.4 million for the years ended December 31, 2011, 2010 and 2009, respectively.

Stock-based compensation. From time to time, the Company exchanges its equity instruments for services provided by employees and directors that are based on the fair value of the Company s equity instruments or that may be settled by the issuance of those equity instruments in exchange for the services. The cost of the services received in exchange for equity instruments, including stock options, is measured based on the grant-date fair value of those instruments. That cost is recognized as compensation expense over the requisite service period (generally the vesting period). Generally, no compensation cost is recognized for equity instruments that do not vest.

Income taxes. The Company recognizes deferred tax assets and liabilities for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rate is recognized in income in the period that includes the enactment date. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized.

The Company evaluates uncertain tax positions for recognition and measurement in the consolidated financial statements. To recognize a tax position, the Company determines whether it is more likely than not that the tax positions will be sustained upon examination, including resolution of any related appeals or litigation, based on the technical merits of the position. A tax position that meets the more likely than not threshold is measured to determine the amount of benefit to be recognized in the consolidated financial statements. The amount of tax benefit recognized with respect to any tax position is measured as the largest amount of benefit that is greater than 50 percent likely of being realized upon settlement. The Company had no uncertain tax positions that required recognition in the consolidated financial statements at December 31, 2011 and 2010. Any interest or penalties would be recognized as a component of income tax expense.

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Reclassifications. Certain prior period amounts have been reclassified to conform to the 2011 presentation. These reclassifications had no impact on net income (loss), total stockholders equity or cash flows.

Recent accounting pronouncements. In December 2011, the Financial Accounting Standards Board (the FASB) issued amendments to enhance disclosures required by U.S. GAAP by requiring improved information about financial instruments and derivative instruments that are either (i) offset in accordance with the current definition of right of setoff or the current balance sheet netting for derivative instruments allowed under current U.S. GAAP or (ii) subject to an enforceable master netting arrangement or similar agreement, irrespective of whether they are offset in accordance with either the definition of right of setoff or the current balance sheet netting for derivative instruments. This information will enable users of an entity s financial statements to evaluate the effect or potential effect of netting arrangements on an entity s financial position, including the effect or potential effect of rights of setoff associated with certain financial instruments and derivative instruments in the scope of the update.

An entity is required to apply the amendments for annual reporting periods beginning on or after January 1, 2013, and interim periods within those annual periods. An entity should provide the disclosures required by those amendments retrospectively for all comparative periods presented. The Company plans to adopt on January 1, 2013 and does not expect this update to have a significant impact on the consolidated financial statements.

Note C. *Exploratory well costs*

The Company capitalizes exploratory well costs until a determination is made that the well has either found proved reserves or that it is impaired. The capitalized exploratory well costs are presented in unproved properties in the consolidated balance sheets. If the exploratory well is determined to be impaired, the well costs are charged to expense.

The following table reflects the Company s capitalized exploratory well activity during each of the years ended December 31, 2011, 2010, and 2009:

	Years Ended December 31,		
(in thousands)	**2011**	**2010**	**2009**
Beginning capitalized exploratory well costs	$ 46,826	$ 8,668	$ 25,553
Additions to exploratory well costs pending the determination of proved reserves	515,916	175,343	135,656
Reclassifications due to determination of proved reserves	(454,975)	(137,185)	(152,200)
Exploratory well costs charged to expense			(341)
Ending capitalized exploratory well costs	$ 107,767	$ 46,826	$ 8,668

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The following table provides an aging at December 31, 2011 and 2010 of capitalized exploratory well costs based on the date the drilling was completed:

(in thousands)	December 31, 2011	December 31, 2010
Wells in drilling progress	$ 24,963	$ 19,190
Capitalized exploratory well costs that have been capitalized for a period of one year or less	82,804	27,636
Capitalized exploratory well costs that have been capitalized for a period greater than one year		
Total capitalized exploratory well costs	$ 107,767	$ 46,826

At December 31, 2011, the Company had 60 gross exploratory wells either drilling or waiting on results from completion. There were 15 wells in the New Mexico Shelf area, 32 wells in Delaware Basin area, 12 wells in the Texas Permian area and 1 well in a non-core area.

Note D. ***Business combinations***

OGX Acquisition. In November 2011, the Company acquired three entities affiliated with OGX Holdings II, LLC (collectively the OGX Acquisition) for cash consideration of approximately $252.4 million, subject to customary post-closing adjustments. The OGX Acquisition was primarily funded with borrowings under the Company s Credit Facility. The results of operations prior to December 2011 do not include results from the OGX Acquisition.

The following table reflects the estimated fair value of the acquired assets and liabilities associated with the OGX Acquisition:

(in thousands)	
Fair value of net assets:	
Current assets, net of cash acquired of $205	$ 9,691
Proved oil and natural gas properties	94,262

Unproved oil and natural gas properties		164,798
Inventory		23
Total assets acquired		268,774
Current liabilities		(16,033)
Asset retirement obligations		(321)
Total liabilities assumed		(16,354)
Net assets acquired	$	252,420
Fair value of consideration paid for net assets:		
Cash consideration, net of cash acquired of $205	$	252,420

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Marbob and Settlement Acquisitions. In July 2010, the Company entered into an asset purchase agreement to acquire certain of the oil and natural gas leases, interests, properties and related assets owned by Marbob Energy Corporation and its affiliates (collectively, Marbob) for aggregate consideration of (i) cash in the amount of $1.45 billion, (ii) the issuance to Marbob of $150 million 8.0% senior note due 2018 and (iii) the issuance to Marbob of approximately 1.1 million shares of the Company s common stock, subject to purchase price adjustments, which included downward purchase price adjustments based on the exercise of third parties of contractual preferential purchase rights in properties to be acquired from Marbob (Marbob Acquisition).

On October 7, 2010, the Company closed the Marbob Acquisition. At closing, the Company paid approximately $1.1 billion in cash plus the senior note and common stock described above for a total purchase price of approximately $1.4 billion. The total purchase price as originally announced was reduced due to third party contractual preferential purchase rights in the Marbob properties. Certain of the third parties contractual preferential purchase rights became subject to litigation, as discussed below.

The Company funded the cash consideration in the Marbob Acquisition with (a) borrowings under its Credit Facility and (b) net proceeds of $292.7 million from a private placement of approximately 6.6 million shares of the Company s common stock at a price of $45.30 per share that closed on October 7, 2010.

Certain of the Marbob interests in properties contained contractual preferential purchase rights by third parties if Marbob were to sell them. Marbob informed the Company of its receipt of a notice from BP America Production Company (BP) electing to exercise its contractual preferential purchase rights in certain of Marbob s properties as a result of the Marbob Acquisition.

On July 20, 2010, BP announced it was selling all its assets in the Permian Basin to a subsidiary of Apache Corporation (Apache). Marbob and BP owned common interests in certain properties subject to contractual preferential purchase rights. BP and Apache contested Marbob s ability to exercise its contractual preferential purchase rights in this situation. As a result, Marbob and the Company filed suit against BP and Apache seeking declaratory judgment and injunctive relief to protect Marbob s contractual right to have the option to purchase these interests in these common properties.

On October 15, 2010, the Company and Marbob resolved the litigation with BP and Apache related to the disputed contractual preferential purchase rights. As a result of the settlement, the Company acquired a non-operated interest in substantially all of the oil and natural gas assets subject to the litigation for approximately $286 million in cash (the Settlement Acquisition). The Company funded the Settlement Acquisition with borrowings under its Credit Facility.

The results of operations of the Marbob and Settlement Acquisitions are included in the Company s results of operations since their respective closing dates in October 2010.

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The following table reflects the estimated fair value of the acquired assets and liabilities associated with the Marbob and Settlement Acquisitions:

(in thousands)	Marbob Acquisition	Settlement Acquisition
Fair value of net assets:		
Proved oil and natural gas properties	$ 1,014,734	$ 185,337
Unproved oil and natural gas properties	334,866	101,582
Other long-term assets	20,771	
Total assets acquired	1,370,371	286,919
Asset retirement obligations and other liabilities assumed	(7,851)	(689)
Net assets acquired	$ 1,362,520	$ 286,230
Fair value of consideration paid for net assets:		
Cash consideration	$ 1,127,747	$ 286,230
Marbob $150 million senior unsecured 8% note, due 2018	159,000 [(a)]	
Common stock, $0.001 par value; 1,103,752 shares issued	75,773 [(b)]	
Total purchase price	$ 1,362,520	$ 286,230

(a) The fair value of the $150 million 8.0% senior unsecured note due 2018 issued to Marbob, was calculated by reference to the traded market yield of Concho's 8.625% senior unsecured notes due 2017, at September 30, 2010.

(b) The fair value of the Concho common stock issued to Marbob was valued at the average of the high and low price on the closing date (October 7, 2010), of $68.65 per share.

Wolfberry acquisitions. In December 2009, together with the acquisition of related additional interests that closed in 2010, the Company closed two acquisitions (the Wolfberry Acquisitions) of interests in producing and non-producing assets in the Wolfberry play in the Permian Basin for approximately $270.7 million. The Wolfberry Acquisitions were funded with borrowings under the Company s Credit Facility. The Company s 2009 results of operations do not include results from the Wolfberry Acquisitions.

The following table reflects the estimated fair value of the acquired assets and liabilities associated with the Wolfberry Acquisitions:

(in thousands)	**Wolfberry Acquisitions**
Fair value of net assets:	
Proved oil and natural gas properties	$ 212,987
Unproved oil and natural gas properties	58,222
Total assets acquired	271,209
Asset retirement obligations	(464)
Net assets acquired	$ 270,745

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Pro forma data. The following unaudited pro forma combined condensed financial data for the year ended December 31, 2010 was derived from the historical financial statements of the Company giving effect to the Marbob and Settlement Acquisitions as if they had occurred on January 1, 2010. The pro forma financial data does not include the results of operations for the OGX Acquisition or Wolfberry Acquisitions as they are not deemed material. The unaudited pro forma combined condensed financial data has been included for comparative purposes only and is not necessarily indicative of the results that might have occurred had these acquisitions taken place as of the date indicated and is not intended to be a projection of future results.

(in thousands, except per share amounts)		Year Ended December 31, 2010 (unaudited)
Operating revenues	$	1,178,138
Net income	$	216,984
Earnings per common share:		
Basic .	$	2.16
Diluted	$	2.14

Note E. ***Asset retirement obligations***

The Company s asset retirement obligations represent the estimated present value of the estimated cash flows the Company will incur to plug, abandon and remediate its producing properties at the end of their productive lives, in accordance with applicable state laws. The Company does not provide for a market risk premium associated with asset retirement obligations because a reliable estimate cannot be determined. The Company has no assets that are legally restricted for purposes of settling asset retirement obligations.

The Company s asset retirement obligation transactions during the years ended December 31, 2011, 2010 and 2009 are summarized in the table below:

	Years Ended December 31,					
(in thousands)		2011		2010		2009
Asset retirement obligations, beginning of period	$	43,326	$	22,754	$	16,809
Liabilities incurred from new wells		7,178		3,037		1,526
Liabilities assumed in acquisitions		527		8,290		488
Accretion expense on continuing operations		2,965		1,482		909

Accretion expense on discontinued operations	8	232	149
Disposition of wells	(463)	(3,236)	(223)
Liabilities settled upon plugging and abandoning wells	(686)	(591)	(1,255)
Revision of estimates	6,830	11,358	4,351
Asset retirement obligations, end of period	$ 59,685	$ 43,326	$ 22,754

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Note F. ***Stockholders equity and treasury stock***

Public common stock offerings. In December 2010, the Company issued in a public offering 2.9 million shares of its common stock at $82.50 per share and received net proceeds of approximately $227.4 million. The Company used the net proceeds from this offering to repay a portion of the borrowings under its Credit Facility.

In February 2010, the Company issued in a public offering 5.3 million shares of its common stock at $42.75 per share and received net proceeds of approximately $219.3 million. The Company used the net proceeds from this offering to repay a portion of the borrowings under its Credit Facility.

Private placement of common stock. In October 2010, the Company closed the private placement of its common stock, simultaneously with the closing of the Marbob Acquisition, on 6.6 million shares of its common stock at a price of $45.30 per share for net proceeds of approximately $292.7 million.

Treasury stock. The restrictions on certain restricted stock awards issued to certain of the Company s officers and key employees lapsed during the years ended December 31, 2011 and 2010. Immediately upon the lapse of restrictions, these officers and key employees became liable for income taxes on the value of such shares. In accordance with the Company s 2006 Stock Incentive Plan (the Plan) and the applicable restricted stock award agreements, some of such officers and key employees elected to deliver shares of the Company s common stock to the Company in exchange for cash used to satisfy such tax liability. In total, the Company had acquired 55,990 and 31,963 shares of the Company s common stock that are held as treasury stock at December 31, 2011 and 2010, respectively.

Note G. ***Incentive plans***

Defined contribution plan. The Company sponsors a 401(k) defined contribution plan for the benefit of substantially all employees. The Company matches 100 percent of employee contributions, not to exceed 6 percent of the employee s annual salary. Effective January 1, 2012, the Company increased the 6 percent to 10 percent. The Company contributions to the plan for the years ended December 31, 2011, 2010 and 2009 were approximately $1.8 million, $0.7 million, and $1.0 million, respectively.

Stock incentive plan. The Plan provides for granting stock options and restricted stock awards to employees and individuals associated with the Company. The following table shows the number of awards available under the Plan at December 31, 2011:

	Number of Common Shares
Approved and authorized awards	5,850,000
Stock option grants, net of forfeitures	(3,463,720)
Restricted stock grants, net of forfeitures	(1,570,256)
Treasury shares	55,990
Awards available for future grant	872,014

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Restricted stock awards. All restricted shares are treated as issued and outstanding in the accompanying consolidated balance sheets. If an employee terminates employment prior the restriction lapse date, the awarded shares are forfeited and cancelled and are no longer considered issued and outstanding. A summary of the Company s restricted stock awards for the years ended December 31, 2011, 2010 and 2009 is presented below:

	Number of Restricted Shares	Grant Date Fair Value Per Share
Restricted stock:		
Outstanding at January 1, 2009	407,351	
Shares granted	300,119	$ 27.10
Shares cancelled / forfeited	(7,874)	
Lapse of restrictions	(202,339)	
Outstanding at December 31, 2009	497,257	
Shares granted	537,415	$ 59.57
Shares cancelled / forfeited	(19,528)	
Lapse of restrictions	(194,260)	
Outstanding at December 31, 2010	820,884	
Shares granted	306,891	$ 95.41
Shares cancelled / forfeited	(59,576)	
Lapse of restrictions	(156,186)	
Outstanding at December 31, 2011	912,013	

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The following table summarizes information about stock-based compensation for the Company s restricted stock awards for the years ended December 31, 2011, 2010 and 2009:

(in thousands)	Years Ended December 31, 2011	2010	2009
***Grant date fair value for awards during the period:* [(a)]**			
Employee grants	$ 19,754	$ 11,823	$ 5,187
Officer and director grants	9,525	20,290	3,256
Total	$ 29,279	$ 32,113	$ 8,443
Stock-based compensation expense from restricted stock:			
Employee grants	$ 7,939	$ 5,207	$ 3,003
Officer and director grants [(a)]	10,452	5,071	1,752
Total	$ 18,391	$ 10,278	$ 4,755
Income taxes and other information:			
Income tax benefit related to restricted stock	$ 7,030	$ 3,931	$ 1,790
Deductions in current taxable income related to restricted stock	$ 15,273	$ 11,289	$ 5,458

(a) The years ended December 31, 2010 and 2009 include effects of modifications to certain stock-based awards, see discussion below.

Stock option awards. A summary of the Company s stock option activity under the Plan for the years ended December 31, 2011, 2010 and 2009 is presented below:

	Years Ended December 31, 2011		2010		2009	
	Number of Options	Weighted Average Exercise Price	Number of Options	Weighted Average Exercise Price	Number of Options	Weighted Average Exercise Price
Stock options:						
Outstanding at beginning of period	1,597,003	$ 15.43	2,156,503	$ 14.11	2,731,324	$ 12.46
Options granted	-	$ -	-	$ -		