A TIME OF TRANSITION.
A YEAR OF GROWTH.

Matador
RESOURCES COMPANY

2011 ANNUAL REPORT

MATADOR STAFF: Surrounding Joe Foran, Matador's Chairman, President and CEO (front row, center) are representatives of the Matador team. We had a total of 41 full-time employees at December 31, 2011.

Matador Resources Company is an independent energy company engaged in the exploration, development, production and acquisition of oil and natural gas resources in the United States. Our focus is on unconventional resource plays with a strong emphasis on shale plays.

Our current operations are primarily in the Eagle Ford shale in south Texas and the Haynesville shale and Cotton Valley in northwest Louisiana and east Texas. We also have acreage positions in west Texas, New Mexico, Wyoming, Utah and Idaho.

A TIME OF TRANSITION.

On February 2, 2012, Matador Resources Company began trading on the New York Stock Exchange under the ticker symbol "MTDR."

On the front cover: Joe and Nancy Foran, along with representatives of the founding shareholders, Board of Directors and management, ring the closing bell at the New York Stock Exchange on March 9, 2012, celebrating Matador's initial public offering.

For more information, please visit our website at www.matadorresources.com.

DEAR SHAREHOLDERS & FRIENDS

As we approach our first shareholders' meeting as a public company, I wanted to share with you my thoughts about this annual report and the year ahead and to invite you to attend the shareholders' meeting scheduled for 10:00 a.m. on June 7, 2012 here in Dallas. In February 2012, Matador Resources Company completed its initial public offering, or "IPO," and began trading on the New York Stock Exchange under the ticker symbol "MTDR." The front cover depicts the essential reason for Matador's long record of success — a lot of good people have worked together for many years to contribute their time, talent and treasure to build a company worthy of taking public. As a result, this past year was a time of exciting transition for Matador, not only from a private to a public company, but also from a natural gas focus to an increasing focus on oil and liquids.

The year 2011 was also one of continued growth for Matador as we achieved record total oil and natural gas production, realized revenues and cash flows — up 79%, 89% and 111%, respectively, from 2010 (see back cover). In addition to these achievements, we more than doubled the PV-10 (present value discounted at 10%) of our oil and natural gas reserves and increased oil production by almost five-fold from approximately 33,000 barrels in 2010 to approximately 154,000 barrels in 2011. Details of these achievements and much more information about Matador and our 2011 performance are provided in the attached Form 10-K annual report.

OIL AND LIQUIDS FOCUS FOR 2012

During the first quarter of 2012, oil prices remained close to or above $100 per barrel, while natural gas prices declined to their lowest levels in many years approaching $2.00 per MMBtu. Accordingly, we plan to continue the transition to exploring and developing the oil and liquids opportunities in our portfolio, and in 2012, most of these efforts will be focused on the Eagle Ford shale play in south Texas. In 2011, we added significantly to our oil and liquids prospective position in the Eagle Ford and now have almost 29,000 net acres throughout the play in what we believe to be the "right neighborhoods." We currently have two contracted drilling rigs operating in south Texas — one in the eastern portion and one in the western portion of the Eagle Ford shale play, and, with success, we plan to operate both rigs continuously in south Texas throughout 2012.

We intend to allocate approximately 84% of our estimated capital investments of $313 million in 2012 to the exploration, development and acquisition of additional interests in the Eagle Ford shale play. Including these anticipated investments in the Eagle Ford, we plan to dedicate 94% of our 2012 capital investments to opportunities prospective for oil and liquids production. Through these efforts, we expect our oil production to increase almost ten-fold in 2012 to between 1.4 and 1.5 million barrels, accounting for approximately 75% to 80% of our total oil and natural gas revenues.

We do not plan to drill any operated Haynesville shale or Cotton Valley wells in northwest Louisiana in 2012 and have allocated approximately 5% of our 2012 capital budget to participating in several non-operated Haynesville wells this year. Virtually all of our Haynesville and Cotton Valley acreage is held by existing production. This gives us a significant "gas bank" and a readily available "gas option" for future development when natural gas prices improve.

The Board, the staff and I are very pleased with our recent accomplishments and even more excited about the opportunities that lie ahead. Following the successful completion of our IPO, we expect another year of strong growth fueled by our ongoing drilling activities in the Eagle Ford shale play. We are optimistic that these efforts will increase the value of our assets, our operational flexibility and our share price as more investors get to know us better.

SHAREHOLDER RELATIONSHIPS

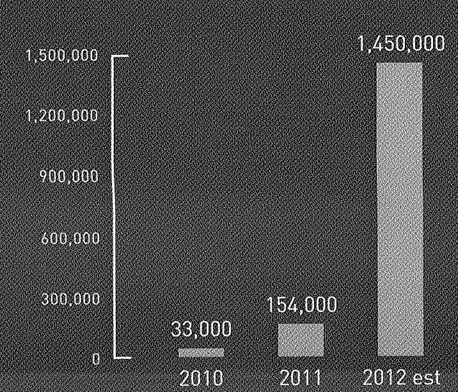
Finally, although the IPO has been a transformational event for Matador, there is one thing that I hope will never change — the special relationships we enjoy with our shareholders. It is still very important to the Board, our staff and to me personally to maintain the close relationships we have enjoyed with our legacy shareholders as a private company and to develop lasting relationships with the new shareholders who have recently invested in Matador. We will continue to work hard to grow our credibility with each of you and to grow the value of your investment in Matador.

Shareholder meetings have always played an important role in our communications, and we usually have more than 100 shareholders present at these meetings. On June 7, we hope to set a new attendance record as we welcome many new shareholders to Dallas and to Matador. Please accept this letter, our annual report and the accompanying proxy materials as your special invitation to attend and to participate in our first annual shareholders' meeting as a public company. We hope it will be an interesting, informational and lively meeting, and we look forward to seeing you there!

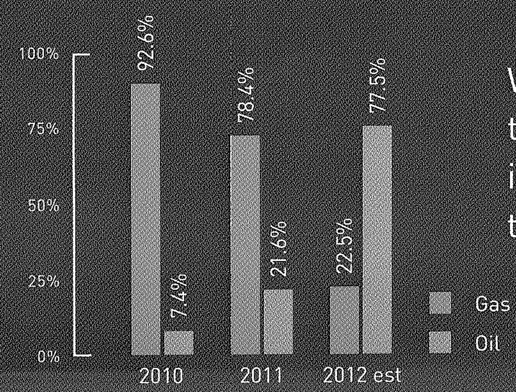
Very truly yours,

JOSEPH WM. FORAN
Chairman, President & CEO

OIL PRODUCTION IN BBLS

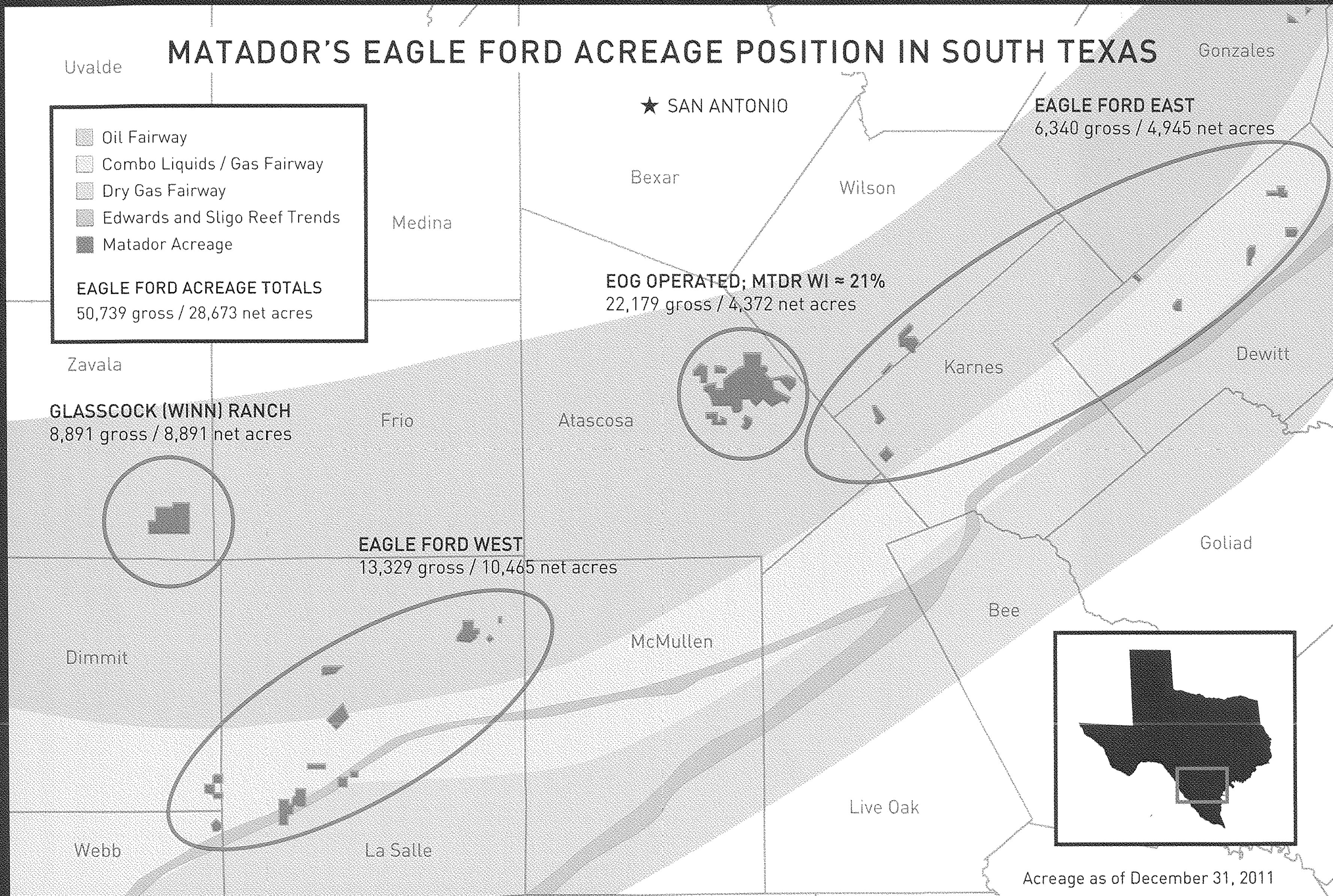


OIL & GAS REVENUE PERCENTAGE



We expect oil production to increase almost ten-fold in 2012, accounting for 75% to 80% of our revenues.

Matador plans to dedicate 94% of its estimated $313 million capital budget in 2012 to opportunities prospective for oil and liquids production, with the majority directed to the Eagle Ford shale in south Texas



Matador's Eagle Ford shale acreage is located primarily in the oil and liquids fairways across the play

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2011

or

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

For the transition period from to

Commission file number 001-34574

Matador Resources Company

(Exact name of registrant as specified in its charter)

Texas	**27-4662601**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
5400 LBJ Freeway, Suite 1500 Dallas, Texas 75240	**75240**
(Address of principal executive offices)	**(Zip Code)**

Registrant's telephone number, including area code: (972) 371-5200

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, par value $0.01 per share	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 ☐ 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 ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☐ No ☒

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K 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 definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

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

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

As of June 30, 2011, the registrant was a privately held company and not publicly traded. Accordingly, the market value of its common stock held by non-affiliates on such date cannot be reasonably determined.

As of March 30, 2012, there were 55,272,860 shares of common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

The information required by Part III of this annual report on Form 10-K, to the extent not set forth herein, is incorporated by reference to the registrant's definitive proxy statement relating to the 2012 Annual Meeting of Shareholders which will be filed with the Securities and Exchange Commission within 120 days after the end of the fiscal year to which this annual report on Form 10-K relates.

MATADOR RESOURCES COMPANY

FORM 10-K

FOR THE FISCAL YEAR ENDED DECEMBER 31, 2011

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Cautionary Note Regarding Forward-Looking Statements

Certain statements in this Annual Report on Form 10-K constitute "forward-looking statements" within the meaning of applicable U.S. securities legislation. Additionally, forward-looking statements may be made orally or in press releases, conferences, reports, on our website or otherwise, in the future, by us or on our behalf. Such statements are generally identifiable by the terminology used such as "anticipate," "believe," "continue," "could," "estimate," "expect," "intend," "may," "might," "potential," "predict," "project," "should" or other similar words.

By their very nature, forward-looking statements require us to make assumptions that may not materialize or that may not be accurate. Forward-looking statements are subject to known and unknown risks and uncertainties and other factors that may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Such factors include, among others: changes in oil or natural gas prices, the timing of planned capital expenditures, availability of acquisitions, uncertainties in estimating proved reserves and forecasting production results, operational factors affecting the commencement or maintenance of producing wells, the condition of the capital markets generally, as well as our ability to access them, the proximity to and capacity of transportation facilities, uncertainties regarding environmental regulations or litigation and other legal or regulatory developments affecting our business, and the other factors discussed below and elsewhere in this report and in other documents that we file with or furnish to the U.S. Securities and Exchange Commission (the "SEC"), all of which are difficult to predict. Forward-looking statements may include statements about:

- our business strategy;
- our reserves;
- our technology;
- our cash flows and liquidity;
- our financial strategy, budget, projections and operating results;
- our oil and natural gas realized prices;
- the timing and amount of future production of oil and natural gas;
- the availability of drilling and production equipment;
- the availability of oil field labor;
- the amount, nature and timing of capital expenditures, including future exploration and development costs;
- the availability and terms of capital;
- our drilling of wells;
- government regulation and taxation of the oil and natural gas industry;
- our marketing of oil and natural gas;
- our exploitation projects or property acquisitions;
- our costs of exploiting and developing our properties and conducting other operations;
- general economic conditions;
- competition in the oil and natural gas industry;

- the effectiveness of our risk management and hedging activities;
- environmental liabilities;
- counterparty credit risk;
- developments in oil-producing and natural gas-producing countries;
- our future operating results;
- estimated future reserves and the present value thereof; and
- our plans, objectives, expectations and intentions contained in this report that are not historical.

Although we believe that the expectations conveyed by the forward-looking statements are reasonable based on information available to us on the date such forward-looking statements were made, no assurances can be given as to future results, levels of activity, achievements or financial condition.

You should not place undue reliance on any forward-looking statement and should recognize that the statements are predictions of future results, which may not occur as anticipated. Actual results could differ materially from those anticipated in the forward-looking statements and from historical results, due to the risks and uncertainties described above, as well as others not now anticipated. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are interdependent upon other factors. The foregoing statements are not exclusive and further information concerning us, including factors that potentially could materially affect our financial results, may emerge from time to time. We do not intend to update forward-looking statements to reflect actual results or changes in factors or assumptions affecting such forward-looking statements.

PART I

Item 1. Business.

In this Annual Report on Form 10-K, references to "we," "our," or "the Company" refer to Matador Resources Company and its subsidiaries before the completion of our corporate reorganization on August 9, 2011 and Matador Holdco, Inc. and its subsidiaries after the completion of our corporate reorganization on August 9, 2011. Prior to August 9, 2011, Matador Holdco, Inc. was a wholly owned subsidiary of Matador Resources Company, now known as MRC Energy Company. Pursuant to the terms of our corporate reorganization, former Matador Resources Company became a wholly owned subsidiary of Matador Holdco, Inc. and changed its corporate name to MRC Energy Company, and Matador Holdco, Inc. changed its corporate name to Matador Resources Company.

Unless the context otherwise requires, the term "common stock" refers to shares of our common stock after the conversion of our Class B common stock into Class A common stock upon the consummation of our initial public offering on February 7, 2012, as the Class A common stock then became the only class of common stock authorized, and the term "Class A common stock" refers to shares of our Class A common stock prior to the automatic conversion of our Class B common stock into Class A common stock upon the consummation of our initial public offering.

For certain oil and natural gas terms used in this report, please see the "Glossary of Oil and Natural Gas Terms" included in this report.

General

We are an independent energy company engaged in the exploration, development, production and acquisition of oil and natural gas resources in the United States, with a particular emphasis on oil and natural gas shale plays and other unconventional resource plays. Our current operations are located primarily in the Eagle Ford shale play in south Texas and the Haynesville shale play in northwest Louisiana and east Texas. We expect the majority of our near-term capital expenditures will focus primarily on increasing our production and reserves from the Eagle Ford shale play. We believe our interests in the Eagle Ford shale play will enable us to create a more balanced commodity portfolio through the drilling of locations that are prospective for oil and liquids. In addition to these primary operating areas, we have acreage positions in southeast New Mexico and west Texas and in southwest Wyoming and adjacent areas in Utah and Idaho where we continue to identify new oil and natural gas prospects.

We are a Texas corporation founded in July 2003 by Joseph Wm. Foran, Chairman, President and CEO, and Scott E. King, Co-Founder and Vice President, Geophysics and New Ventures. Mr. Foran began his career as an oil and natural gas independent in 1983 when he founded Foran Oil Company with $270,000 in contributed capital from 17 friends and family members. Foran Oil Company was later contributed to Matador Petroleum Corporation upon its formation by Mr. Foran in 1988. Mr. Foran served as Chairman and Chief Executive Officer of that company from its inception until it was sold in June 2003 to Tom Brown, Inc., in an all cash transaction for an enterprise value of approximately $388.5 million.

Since our first well in 2004, we have drilled or participated in drilling 236 wells through December 31, 2011, including 106 Haynesville and nine Eagle Ford wells. From December 31, 2008 through December 31, 2011, we grew our estimated proved reserves from 20.0 Bcfe to 193.2 Bcfe. At December 31, 2011, 34% of our estimated proved reserves were proved developed reserves, 12% of our estimated proved reserves were oil and 88% of our estimated proved reserves were natural gas. Our average daily production for the year ended December 31, 2011 was 42.3 MMcfe per day, including 39.8 MMcf of natural gas per day and 422 Bbl of oil per day as compared to an average daily production of 23.6 MMcfe per day, including 23.0 MMcf of natural gas per day and 91 Bbl of oil per day for the year ended December 31, 2010. We have achieved this growth while lowering operating costs (consisting of lease operating expenses and production taxes and marketing expenses) from $1.16 per Mcfe for the year ended December 31, 2009, to $0.88 per Mcfe for the year ended December 31, 2011, or a decrease of approximately 24%.

The following table presents certain summary data for each of our operating areas as of and for the year ended December 31, 2011:

		Producing Wells		Total Identified Drilling Locations(1)		Estimated Net Proved Reserves		Avg. Daily Production (MMcfe)
	Net Acreage	Gross	Net	Gross	Net	Bcfe(2)	% Developed	
South Texas:								
Eagle Ford	28,673	9.0	7.3	193.0	153.1	27.9	37.9	3.3
Austin Chalk	14,849	–	–	16.0	16.0	–	–	–
Area Total(3)	28,673	9.0	7.3	209.0	169.1	27.9	37.9	3.3
NW Louisiana/E Texas:								
Haynesville	14,527	106.0	11.6	524.0	102.9	150.4	26.4	32.3
Cotton Valley(4)	23,054	108.0	71.7	60.0	36.0	14.2	100.0	6.5
Area Total(5)	25,339	214.0	83.3	584.0	138.9	164.6	32.7	38.8
SW Wyoming, NE Utah, SE Idaho	135,862	–	–	–	–	–	–	–
SE New Mexico, West Texas	6,658	13.0	5.7	–	–	0.7	100.0	0.2
Total	196,532	236.0	96.3	793.0	308.0	193.2	33.7	42.3

(1) These locations have been identified for potential future drilling and are not currently producing. In addition, the total net identified drilling locations is calculated by multiplying the gross identified drilling locations in an operating area by our working interest participation in such locations. At December 31, 2011, these identified drilling locations included 8 gross and 8 net locations to which we have assigned proved undeveloped reserves in the Eagle Ford and 102 gross and 17 net locations to which we have assigned proved undeveloped reserves in the Haynesville. We have no proved undeveloped reserves assigned to identified drilling locations in the Austin Chalk or Cotton Valley at December 31, 2011.

(2) These estimates were prepared by our engineering staff and audited by independent reservoir engineers, Netherland, Sewell & Associates, Inc.

(3) Some of the same leases cover the net acres shown for the Eagle Ford formation and the Austin Chalk formation, a shallower formation than the Eagle Ford formation. Therefore, the sum of the net acreage for both formations is not equal to the total net acreage for south Texas. This total includes acreage that we are producing from or that we believe to be prospective for these formations.

(4) Includes shallower zones and also includes one well producing from the Frio formation in Orange County, Texas and two wells producing from the San Miguel formation in Zavala County, Texas.

(5) Some of the same leases cover the net acres shown for the Haynesville formation and the Cotton Valley formation, a shallower formation than the Haynesville formation. Therefore, the sum of the net acreage for both formations is not equal to the total net acreage for northwest Louisiana/east Texas. This total includes acreage that we are producing from or that we believe to be prospective for these formations.

At December 31, 2011, our properties included approximately 51,000 gross acres and 29,000 net acres in the Eagle Ford shale play in Atascosa, DeWitt, Dimmit, Karnes, LaSalle, Gonzales, Webb, Wilson and Zavala Counties in south Texas. We believe that approximately 85% of our Eagle Ford acreage is prospective predominantly for oil or liquids production. In addition, portions of the acreage are also prospective for other targets, such as the Austin Chalk, Olmos and Buda, from which we expect to produce predominantly oil and liquids. Approximately 80% of our Eagle Ford acreage is either held by production or not burdened by lease expirations before 2013. We have begun to explore and develop our Eagle Ford position and from November 2010 through December 2011, we completed our first seven operated wells in this area.

At December 31, 2011, we have identified 193 gross locations and 153 net locations for potential future drilling on our Eagle Ford acreage. These locations have been identified on a property-by-property basis and take into account criteria such as anticipated geologic conditions and reservoir properties, estimated recoveries from nearby wells based on available public data, drilling densities observed from other operators, estimated drilling and completion costs, spacing and other rules established by regulatory authorities and surface considerations, among others. At December 31, 2011, we have identified potential drilling locations on approximately 75% of our net Eagle Ford acreage. As we explore and develop our Eagle Ford acreage further, we believe it is possible that we may identify additional locations for drilling. At December 31, 2011, these identified potential future drilling locations in the Eagle Ford shale play included 8 gross and 8 net locations to which we have assigned proved undeveloped reserves.

In addition, at December 31, 2011, we had approximately 23,000 gross acres and 15,000 net acres in the Haynesville shale play in northwest Louisiana and east Texas. Based on our analysis of geologic and petrophysical information (including total organic carbon content and maturity, resistivity, porosity and permeability, among other information), well performance data and information available to us related to drilling activity and results from wells drilled across the Haynesville shale play, approximately 5,500 of our net acres are located in what we believe is the core area of the play. We believe the core area of the play includes that area in which the most Haynesville wells have been drilled by operators and from which we anticipate natural gas recoveries would likely exceed 6 Bcf per well. Over 90% of our Haynesville acreage is held by production from the Haynesville or other formations, and we believe much of it is also prospective for the Cotton Valley, Hosston (Travis Peak) and other shallower formations. In addition, we believe approximately 1,700 of these net acres are prospective for the Middle Bossier shale play.

At December 31, 2011, we have identified 524 gross locations and 103 net locations for potential future drilling in our Haynesville acreage. These locations have been identified on a property-by-property basis and take into account criteria such as anticipated geologic conditions and reservoir properties, estimated recoveries from our producing Haynesville wells and other nearby wells based on available public data, drilling densities observed from other operators including on some of our non-operated properties, estimated drilling and completion costs, spacing and other rules established by regulatory authorities and surface conditions, among others. Of the 524 gross locations identified for future drilling, 449 of these locations (52 net locations) have been identified within the 5,500 net acres that we believe are located in the core area of the Haynesville play. As we explore and develop our Haynesville acreage further, we believe it is possible that we may identify additional locations for future drilling. At December 31, 2011, these identified potential future drilling locations included 102 gross and 17 net locations in the Haynesville shale play to which we have assigned proved undeveloped reserves.

We also have a large unevaluated acreage position in southwest Wyoming and adjacent areas in Utah and Idaho where we began drilling our initial well in February 2011 to test the Meade Peak natural gas shale. We reached a depth of 8,200 feet, approximately 300 feet above the top of the Meade Peak shale, before having operations suspended for several months due to wildlife restrictions. We resumed operations on this initial test well in September 2011 and completed drilling and coring operations on this well in November 2011. At December 31, 2011, this well had not been completed, as we were still evaluating the well logs and awaiting results from various core analysis tests. In addition, we have leasehold interests in the Delaware and Midland Basins in southeast New Mexico and west Texas where we are developing new oil and natural gas prospects.

We are active both as an operator and as a co-working interest owner with larger industry participants including affiliates of Chesapeake Energy Corporation, EOG Resources, Inc., Royal Dutch Shell plc and others. Of the 236 gross wells we have drilled or participated in drilling, we drilled approximately 40% of these wells as the operator, although our working interest is small in many of the non-operated wells, particularly in the Haynesville shale. At December 31, 2011, we were the operator for approximately 85% of our Eagle Ford and 70% of our Haynesville acreage, including approximately 22% of our acreage in what we believe is the core area of the Haynesville play. A large portion of our acreage in that core area is operated by a subsidiary of Chesapeake Energy Corporation. We also operate all of our acreage in southwest Wyoming and the adjacent areas of Utah and Idaho, as well as the vast majority of our acreage in southeast New Mexico and west Texas.

We are a non-operating working interest participant with affiliates of Chesapeake Energy Corporation, Royal Dutch Shell plc and several other companies in the Haynesville shale and with EOG Resources, Inc. in the Eagle Ford shale. We have entered into a joint operating agreement with an affiliate of Chesapeake Energy Corporation governing the Haynesville operations underlying our Elm Grove/Caspiana properties in southern Caddo Parish, Louisiana and a joint operating agreement with EOG Resources, Inc. governing all operations on our joint acreage in Atascosa County, Texas. We have not entered into a joint operating agreement with Royal Dutch Shell plc or certain other operators of wells in the Haynesville area in which we have a minority working interest. Particularly when our working interest is small, we do not always enter into formal operating agreements with the operators, and in such cases, we rely on applicable legal and statutory authority to govern our arrangement in accordance with industry standard practices.

Where we do have joint operating agreements with affiliates of Chesapeake Energy Corporation and EOG Resources, Inc., these agreements call for significant penalties should we elect not to participate in the drilling and completion of a well proposed by the operator, or a non-consent well. These non-consent penalties typically allow the operator to recover up to 400% of its costs to drill, complete and equip the non-consent well from the well's future net revenue prior to us being allowed to participate in the non-consent well for our original working interest. Ultimately, the amount of these penalties may result in us having no participation at all in the non-consent well. We also have the right to propose wells under these joint operating agreements, and the same non-consent penalties apply to the operator should it elect not to consent to a well that we propose.

While we do not have direct access to our operating partners' drilling plans with respect to future well locations, we do attempt to maintain ongoing communications with the technical staff of these operators in an effort to understand their drilling plans for purposes of our capital expenditure budget and our booking of any related proved undeveloped well locations. We review these locations with Netherland, Sewell & Associates, Inc., our independent reservoir engineers, on a periodic basis to ensure their concurrence with our estimates of these drilling plans and our approach to booking these reserves.

The following table presents our 2012 anticipated capital expenditure budget of approximately $313.0 million segregated by target formation and by whether the wells are expected to be exploration or development wells.

	2012 Anticipated Drilling						2012 Anticipated Capital Expenditure Budget		
	Gross Wells(1)			Net Wells(1)			(in millions)(2)		
	Exploration	Development	Total	Exploration	Development	Total	Exploration	Development	Total
South Texas									
Eagle Ford	13.0	15.0	28.0	11.8	13.8	25.6	$122.3	$134.9	$257.2
Austin Chalk	2.0	–	2.0	2.0	–	2.0	11.3	–	11.3
Area Total	15.0	15.0	30.0	13.8	13.8	27.6	133.6	134.9	268.5
NW Louisiana / E Texas									
Haynesville	6.0	19.0	25.0	0.2	1.3	1.5	1.9	11.6	13.5
Cotton Valley	–	–	–	–	–	–	–	–	–
Area Total	6.0	19.0	25.0	0.2	1.3	1.5	1.9	11.6	13.5
SW Wyoming, NE Utah, SE Idaho	1.0	–	1.0	0.4	–	0.4	2.5	–	2.5(3)
SE New Mexico, West Texas	–	–	–	–	–	–	–	–	–
Other	N/A	N/A	N/A	N/A	N/A	N/A	25.0	3.5	28.5(4)
Total	22.0	34.0	56.0	14.4	15.1	29.5	$163.0	$150.0	$313.0

(1) Includes wells we currently expect to drill and complete as operator, plus those wells in which we currently plan to participate as a non-operator in 2012.

(2) Our capital expenditure budget is based on our net working interests in the properties.

(3) We have a carried interest for $5.0 million of the cost of this well presuming the election of our joint venture partner to participate in the drilling of this well.

(4) Includes $20.0 million to acquire additional leasehold interests primarily prospective for oil and liquids production in southeast New Mexico and west Texas.

Although we intend to allocate a portion of our 2012 capital expenditure budget to financing exploration, development and acquisition of additional interests in the Haynesville shale play, we currently intend to allocate approximately 84% of our 2012 capital expenditure budget to the exploration, development and acquisition of additional interests in the Eagle Ford shale play. Including these anticipated capital expenditures in the Eagle Ford shale play, we plan to dedicate about 94% of our 2012 anticipated capital expenditure budget to opportunities prospective for oil and liquids production. While we have budgeted $313.0 million for 2012, the aggregate amount of capital we will expend may fluctuate materially based on market conditions and our drilling results. Since at December 31, 2011, over 90% of our Haynesville acreage was held by production and approximately 80% of our Eagle Ford acreage was either held by production or not burdened by lease expirations before 2013, we possess the financial flexibility to allocate our capital when we believe it is economical and justified.

Recent Developments

At March 30, 2012, we had drilled an aggregate of 15 Eagle Ford horizontal wells in south Texas as operator, including 10 wells in LaSalle County, one well in Dimmit County, three wells in Karnes County and one well in DeWitt County. Thirteen of these wells have been completed and are producing and two of these wells are awaiting completion. At March 30, 2012, we had two contracted drilling rigs operating in the Eagle Ford play in south Texas: one in LaSalle County and one in Karnes County.

On February 7, 2012, we completed our initial public offering of 14,883,334 shares of common stock at $12.00 per share. We sold 12,209,167 shares of common stock in this offering and certain selling shareholders sold 2,674,167 shares of common stock, including shares sold by us and the selling shareholders pursuant to the partial exercise of the underwriters' over-allotment option on March 7, 2012.

Between November 2011 and February 2012, we entered into various costless collars to mitigate our exposure to oil price volatility and enhance predictability of our cash flows. As of March 30, 2012, we had hedged a total of 1,180,000 Bbls of oil for 2012, 1,260,000 Bbls of oil for 2013 and 120,000 Bbls of oil for 2014. For 2012, these collars have a weighted average price floor of $90.51 per Bbl and a weighted average price ceiling of $109.84 per Bbl. For 2013, these collars have a weighted average price floor of $87.14 per Bbl and a weighted average price ceiling of $110.26 per Bbl. For 2014, these collars have a weighted average price floor of $90.00 per Bbl and a weighted average price ceiling of $114.90 per Bbl.

In December 2011, we amended and restated our senior secured revolving credit agreement. This amendment increased the maximum facility amount from $150.0 million to $400.0 million. Borrowings are limited to the lesser of $400.0 million or the borrowing base, which was $125.0 million as of March 30, 2012.

In November and December 2011, we completed three operated Eagle Ford horizontal wells, the Martin Ranch #2H, #3H and #5H in northeastern LaSalle County, Texas. During initial flow tests on these wells, the Martin Ranch #2H tested at approximately 1,310 Bbls of oil and 1.8 MMcf of natural gas per day, the Martin Ranch #3H tested at approximately 620 Bbls of oil and 0.5 MMcf of natural gas per day, and the Martin Ranch #5H tested at approximately 810 Bbls of oil and 0.6 MMcf of natural gas per day. All three wells were turned to sales in late December 2011. We are the operator and have a 100% working interest in these three wells.

Between March and July 2011, we acquired leasehold interests in approximately 6,300 gross and 4,800 net acres in DeWitt, Karnes, Wilson and Gonzales Counties, Texas in the Eagle Ford shale play from Orca ICI Development, JV. We believe that all of this acreage is in an oil and liquids prone area of the Eagle Ford play. We believe that the acreage in Wilson and Gonzales Counties and a portion of DeWitt County will be prospective for oil and liquids from the Austin Chalk formation in addition to the Eagle Ford. We paid approximately $31.5 million to acquire this acreage. We currently own a 50% working interest in the acreage (approximately 2,800 gross and 1,400 net acres) in DeWitt County and are the operator. We currently own a 100% working interest in the acreage (approximately 3,500 gross and 3,400 net acres) in Karnes, Wilson and Gonzales Counties and are the operator.

Principal Areas of Interest

Our focus since inception has been the exploration for oil and natural gas in unconventional resource plays with a particular focus over the last few years in the Haynesville shale play and more recently in the Eagle Ford shale play. Our exploration efforts have concentrated primarily on known hydrocarbon-producing basins with well-established production histories offering the potential for multiple-zone completions. We have also sought to balance the risk profile of our prospects, as well as to explore for more conventional targets in addition to the unconventional resource plays.

At December 2011, our principal areas of interest consisted of (1) the Eagle Ford shale play in south Texas, (2) the Haynesville shale play, including the Middle Bossier shale play, as well as the traditional Cotton Valley and Hosston (Travis Peak) formations in northwest Louisiana and east Texas, (3) the Meade Peak shale play in southwest Wyoming and the adjacent areas of Utah and Idaho and (4) southeast New Mexico and west Texas, including the Delaware and Midland Basins.

South Texas

Eagle Ford Shale and Other Formations

About 8% of our daily production, or 3.3 MMcfe per day, including 331 Bbls of oil per day and 1.3 MMcf of natural gas per day, was produced from the Eagle Ford shale in south Texas for the year ended December 31, 2011. The Eagle Ford contributed approximately 78% of our daily oil production and about 3% of our daily natural gas production for 2011. For the month of December 2011, about 13% of our daily production, or 5.6 MMcfe per day, including 706 Bbls of oil per day and 1.3 MMcf per day, was produced from the Eagle Ford. During December 2011, the Eagle Ford contributed 91% of our daily oil production and about 4% of our daily natural gas production. At December 31, 2011, approximately 14% of our proved reserves, or 27.9 Bcfe, was attributable to the Eagle Ford, including approximately 3.6 million Bbls of oil and 6.1 Bcf of natural gas. Our Eagle Ford proved reserves at December 31, 2011 comprised approximately 96% of our proved oil reserves and approximately 4% of our proved natural gas reserves. The present value discounted at 10% for our proved reserves in the Eagle Ford at December 31, 2011 was $130.2 million, or about 52% of the PV-10 for our total proved reserves of $248.7 million. We anticipate that the percentage of our daily production and reserves attributable to the Eagle Ford shale will grow in 2012 as we intend to allocate approximately 84% of our 2012 capital expenditure budget to the exploration, development and acquisition of additional interests in the Eagle Ford play in an effort to grow the oil and liquids component of our production and reserves.

The Eagle Ford shale extends across portions of south Texas from the Mexican border into east Texas forming a band roughly 50 to 100 miles wide and 400 miles long. The Eagle Ford is an organically rich calcareous shale, in places transitioning to an organic, argillaceous lime-mudstone. It lies between the deeper Buda limestone and the shallower Austin Chalk formation. Most, if not all, of the oil found in the Austin Chalk and Buda formations is generally believed to be sourced from the Eagle Ford shale. In the prospective areas for the Eagle Ford shale, the interval averages 200 feet thick, is found at depths ranging from as shallow as 4,000 feet to as deep as 13,000 feet, and in much of the deeper portions of the play is overpressured. The Eagle Ford shale has a total organic carbon content of 1% to 7% that is comparable to the Haynesville shale, and is generally porous, with core-measured porosities ranging between 4% and 14%.

Along the entire length of the Eagle Ford trend the structural dip of the formation is consistently down to the south with relatively few, modestly sized structural perturbations. As a result, depth of burial increases consistently southwards along with the thermal maturity of the formation. Where the formation is shallow, it is less thermally mature and therefore more oil prone, and as it gets deeper and becomes more thermally mature, the Eagle Ford shale is more natural gas prone. The transition between being more oil prone and more natural gas prone includes an interval that typically produces wet gas with condensate. We believe that approximately 85% of our Eagle Ford acreage lies within those portions of the Eagle Ford shale that are prone to produce oil or wet gas with condensate.

Most of the current Eagle Ford shale activity is concentrated in Atascosa, Bee, DeWitt, Dimmit, Frio, Gonzales, Karnes, LaSalle, Lavaca, Live Oak, Maverick, McMullen, Webb, Wilson and Zavala Counties in south Texas. The first horizontal wells drilled specifically for the Eagle Ford shale were drilled in 2008, leading to a discovery in LaSalle County. Since then, the play has expanded significantly across a large portion of south Texas.

Publicly available information indicates that operators are typically drilling 3,500 to 7,000 feet horizontal laterals and applying hydraulic fracture stimulation in multiple stages along the full length of the horizontal laterals to complete the wells and establish production. Although production rates vary across the different areas of the play, initial production rates in the oil areas have been reported as high as 1,000 to 1,500 Bbls of oil per day with varying amounts of associated natural gas. In the natural gas areas of the Eagle Ford play, initial production rates as high as 5.0 to 15.0 MMcfe per day have been reported with varying amounts of associated oil and liquids.

At December 31, 2011, our aggregate leasehold interests consisted of approximately 51,000 gross acres and 29,000 net acres in the Eagle Ford shale play in Atascosa, DeWitt, Dimmit, Karnes, LaSalle, Gonzales, Webb, Wilson and Zavala Counties in south Texas. We believe portions of this acreage are also prospective for the Austin Chalk, Buda, Olmos and other formations, from which we expect to produce predominantly oil and liquids. In particular, the Austin Chalk formation, which is a naturally fractured carbonate ranging in thickness from 200 to 400 feet, has produced from several fields on or nearby portions of our acreage. Our Zavala County acreage, for example, is located within the historic Pearsall (Austin Chalk) field.

We believe that approximately 85% of our Eagle Ford acreage is prospective predominantly for oil and liquids. At December 31, 2011, we owned a 100% working interest in approximately 26,000 gross acres and 23,000 net acres in Dimmit, Gonzales, Karnes, LaSalle, Webb, Wilson and Zavala Counties and a 50% working interest in approximately 2,800 gross and 1,400 net acres in DeWitt County and are the operator of this acreage. We also owned an approximate 21% working interest in approximately 22,000 gross acres in Atascosa County operated by EOG Resources, Inc. At December 31, 2011, approximately 80% of our Eagle Ford acreage was either held by production or not burdened by lease expirations before 2013.

At December 31, 2011, we had drilled and completed seven Eagle Ford wells on our operated properties. All of these wells were producing to sales, although four of these wells were initially placed on production in late December. At December 31, 2011, we had also participated in two Eagle Ford wells with EOG Resources, Inc. as operator, on the Atascosa County acreage. Our first operated Eagle Ford horizontal well, the JCM Jr. Minerals #1H in southern LaSalle County along the Edwards Reef, was completed in November 2010. First sales of oil and natural gas began from this well in late January 2011, and during December 2011, the well produced at an average daily rate of approximately 0.5 MMcf of natural gas and 9 Bbls of condensate per day, and through December 31, 2011, had produced a total of approximately 430 MMcf of natural gas and 11,200 Bbls of condensate. Our second operated Eagle Ford horizontal well, the Martin Ranch #1H in northeastern LaSalle County, was completed in January 2011 and tested approximately 1,200 Bbls of oil per day during an initial flow test. First sales of oil and natural gas from this well began in late March at approximately 700 Bbls of oil and 350 Mcf of natural gas per day. During December 2011, the well produced at an average daily rate of approximately 330 Bbls of oil and 0.6 MMcf of natural gas per day, and through December 31, 2011, had produced a total of 117,000 Bbls of oil and 144 MMcf of natural gas.

Our third operated Eagle Ford horizontal well, the Affleck #1H, was completed in February 2011 in eastern Dimmit County, Texas, and tested at approximately 415 Bbls of oil and 5.4 MMcf of natural gas per day during an initial flow test. During December 2011, the well produced at an average daily rate of 0.8 MMcf of natural gas and 38 Bbls of oil per day. In August 2011, we completed our fourth operated Eagle Ford horizontal well, the Lewton #1H in DeWitt County, Texas. This well tested at approximately 2.7 MMcf of natural gas and 1,040 Bbls of condensate per day during an initial flow test. The Lewton well began producing to sales in late December 2011.

In November and December 2011, we completed three additional operated Eagle Ford horizontal wells, the Martin Ranch #2H, #3H and #5H, in northeastern LaSalle County, Texas. During initial flow tests on these wells, the Martin Ranch #2H tested at approximately 1,310 Bbls of oil and 1.8 MMcf of natural gas per day, the Martin Ranch #3H tested at approximately 620 Bbls of oil and 0.5 MMcf of natural gas per day, and the Martin Ranch #5H tested at approximately 810 Bbls of oil and 0.6 MMcf of natural gas per day. All three wells were turned to sales in late December 2011.

Between March and July 2011, we acquired leasehold interests in approximately 6,300 gross and 4,800 net acres in DeWitt, Karnes, Wilson and Gonzales Counties, Texas in the Eagle Ford shale play from Orca ICI Development, JV. We paid approximately $31.5 million to acquire this acreage. We currently own a 50% working interest in the acreage (approximately 2,800 gross and 1,400 net acres) in DeWitt County and are the operator. We currently own a 100% working interest in the acreage (approximately 3,500 gross and 3,400 net acres) in Karnes, Wilson and Gonzales Counties and are the operator. At December 31, 2011, we had drilled and completed only one well on this acreage, the Lewton #1H in DeWitt County.

We will pay 100% of the costs to drill and complete the first six wells drilled on the acreage in DeWitt County. We will have an 85% working interest in these six wells until we have recovered all of our acquisition, drilling and completion costs from each well, at which time Orca's working interest will increase to 50%. When the cumulative production from each of the first six wells reaches 500,000 BOE, on a well-by-well basis, then Orca's working interest in that well increases to 55%. If the cumulative production from each of the first six wells reaches 750,000 BOE, on a well-by-well basis, then Orca's working interest in that well will increase to 70%. Both we and Orca will own a 50% working interest in all subsequent wells drilled after the first six wells on the acreage in DeWitt County.

We will have a 100% working interest in the first five wells drilled on the acreage in Karnes, Wilson and Gonzales Counties. When we have recovered all of our acquisition, drilling and completion costs from each of these five wells, Orca may elect, on a well-by-well basis, to back-in for a 25% working interest in these wells. In addition, Orca retains a one-time election for a short period of time after we complete these first five wells to participate for a 25% working interest in all subsequent wells drilled on this acreage by paying a purchase price equal to 25% of our costs to acquire the acreage in Karnes, Wilson and Gonzales Counties.

At March 30, 2012, we had drilled an aggregate of 15 Eagle Ford horizontal wells in south Texas as operator, including 10 wells in LaSalle County, one well in Dimmit County, three wells in Karnes County and one well in DeWitt County. Thirteen of these wells have been completed and are producing and two of these wells are awaiting completion. At March 30, 2012 we had two contracted drilling rigs operating in the Eagle Ford play in south Texas: one in LaSalle County and one in Karnes County. We are not currently experiencing difficulties in securing completion, and particularly hydraulic fracturing services, for our newly drilled wells, although we experienced these problems at various times during 2011 in south Texas and may have such difficulties again in the future. We believe that maintaining reliable and timely drilling and completion services and reducing drilling and completion costs will be essential to the successful development and profitability of the Eagle Ford shale play. See "Risk Factors – The Unavailability or High Cost of Drilling Rigs, Completion Equipment and Services, Supplies and Personnel, Including Hydraulic Fracturing Equipment and Personnel, Could Adversely Affect Our Ability to Establish and Execute Exploration and Development Plans within Budget and on a Timely Basis, Which Could Have a Material Adverse Effect on Our Financial Condition, Results of Operations and Cash Flows."

We experienced temporary pipeline interruptions from time to time during 2011 associated with natural gas production from our Eagle Ford wells and have been required to either shut in wells for brief periods or to flare some of the natural gas we produce. At March 30, 2012, we were experiencing pipeline capacity limitations at our Martin Ranch lease in LaSalle County and are currently flaring a portion of the natural gas we are producing there as a result. We believe that these pipeline interruptions and capacity constraints are temporary and that additional oil and natural gas pipeline infrastructure currently being built throughout south Texas will help to alleviate these problems within 60 to 90 days. If we were required to shut in our production for long periods of time due to these pipeline interruptions, it could have a material adverse effect on our business, financial condition, results of operations and cash flows. See "Risk Factors – The Marketability of Our Production Is Dependent Upon Oil and Natural Gas Gathering and Transportation Facilities Owned and Operated by Third Parties, and the Unavailability of Satisfactory Oil and Natural Gas Transportation Agreements Would Have a Material Adverse Effect on Our Revenue."

In addition to the Eagle Ford potential on our acreage, we believe that approximately 24,000 gross acres and 15,000 net acres in south Texas are prospective primarily for the Austin Chalk formation, which has historically been targeted by operators in south Texas. We have not yet drilled an Austin Chalk well, and although we believe that other prospective well locations exist on this acreage, we have only included 16 gross and net well locations in our total identified drilling locations at December 31, 2011.

Northwest Louisiana and East Texas

At December 31, 2011, most of our production and proved reserves was attributable to our acreage in northwest Louisiana and east Texas. For the year ended December 31, 2011, about 76% of our daily production, or 32.3 MMcfe per day, was produced from the Haynesville shale, with another 15%, or 6.5 MMcfe per day, produced from the Cotton Valley and other shallower formations in this area. At December 31, 2011, approximately 78% of our proved reserves, or 150.4 Bcfe, were attributable to the Haynesville shale underlying this acreage with another 7% of our proved reserves, or 14.2 Bcfe, associated with the Cotton Valley and shallower formations. In addition, we are evaluating the Bossier shale play which is generally encountered above the Haynesville shale and below the Cotton Valley formation.

We operate all of our Cotton Valley and shallower production under this acreage, as well as all of our Haynesville production on the acreage outside of what we believe to be the core area of the Haynesville play. Of the approximately 5,500 net acres that we consider to be in the core area of the Haynesville play, we operate about 22% of that acreage.

In recent months, natural gas prices have declined to their lowest levels in many years, and at March 30, 2012, the NYMEX Henry Hub natural gas futures contract for the earliest delivery date closed at $2.13 per MMBtu. We would not expect to drill any operated natural gas wells in either our Haynesville or Cotton Valley properties until natural gas prices improved substantially from these levels or unless the costs to drill and complete these wells were also to decline substantially from their recent levels. See "Risk Factors – Our Identified Drilling Locations Are Scheduled Out Over Several Years, Making Them Susceptible to Uncertainties That Could Materially Alter the Occurrence or Timing of Their Drilling."

Haynesville and Middle Bossier Shales

The Haynesville shale is an organically rich, overpressured marine shale found below the Cotton Valley and Bossier formations and above the Smackover formation at depths ranging from 10,500 to 13,500 feet across a broad region throughout northwest Louisiana and east Texas, including principally Bossier, Caddo, DeSoto and Red River Parishes in Louisiana and Harrison, Rusk, Panola and Shelby Counties in Texas. The Haynesville shale has a typical thickness ranging from 100 to 300 feet. Total organic carbon ranges from 0.5% to 5.0%, with core-measured porosities from 3% to 15%. The Haynesville shale produces primarily dry natural gas with almost no associated liquids.

The oil and natural gas industry has focused significant attention on the Haynesville shale play over the last several years. Operators are typically drilling 4,500 to 5,000 feet horizontal laterals and applying hydraulic fracture stimulation in multiple stages along the entire length of the horizontal laterals to complete the wells and establish production. Although initial production rates vary widely across the play, initial production rates as high as 20.0 to 25.0 MMcf per day of natural gas have been reported by operators from horizontal wells drilled and completed in the Haynesville shale.

The Bossier shale is overpressured and is often divided into lower, middle and upper units. The Middle Bossier shale appears to be productive for natural gas under large portions of DeSoto, Red River and Sabine Parishes in Louisiana and Shelby and Nacogdoches Counties in Texas, where it shares many similar productive characteristics to the deeper Haynesville shale. Typically, the Middle Bossier shale is found at depths ranging from 500 to 800 feet shallower than the Haynesville shale, has a typical thickness ranging from 150 to 300 feet, has core-measured porosities ranging between 5% and 14%, and total organic carbon values between 0.5% and 4%. Although there is some overlap between the Bossier and Haynesville shale plays, the two plays appear quite distinct and a separate horizontal wellbore is typically needed for each formation.

At December 31, 2011, we had leasehold and mineral interests in approximately 23,000 gross and 15,000 net acres prospective for the Haynesville shale. Portions of our acreage are located in Caddo, DeSoto, Bossier and Red River Parishes, Louisiana and in Harrison County, Texas. This acreage includes approximately 5,500 net acres in what we believe is the core area of the play. Over 90% of our Haynesville acreage is held by production and portions of it are also producing from and, we believe, prospective for the Cotton Valley, Hosston (Travis Peak) and other shallower formations. In addition, we believe that approximately 1,700 net acres are prospective for the Middle Bossier play as well. We have not yet drilled a Middle Bossier shale well, and, although we believe that prospective well locations exist on this acreage, we have not yet included any Middle Bossier locations in our identified drilling locations at December 31, 2011.

Within the 5,500 net acres that we believe to be in the core area of the Haynesville shale play, we are the operator in two sections where we have working interests of 95% and 100% in all wells to be drilled. In October 2010, as operator, we drilled and completed our L.A. Wildlife H #1 horizontal Haynesville well in the section in which we have a 95% working interest and on December 31, 2010 first sales of natural gas began from this well. During December 2011, the well produced at an average daily rate of approximately 8.7 MMcf of natural gas per day, and through December 31, 2011, had produced a total of approximately 3.4 Bcf of natural gas. In March 2011, we completed our operated Williams 17 H #1 horizontal Haynesville well on the second section where we have a 100% working interest. During December 2011, this well produced at an average daily rate of 3.9 MMcf of natural gas per day and, through December 31, 2011, had produced approximately 1.8 Bcf of natural gas. We began producing both of these wells at a constrained rate of about 10.0 MMcf of natural gas per day. We have identified 12 gross and approximately 12 net potential additional Haynesville locations that we may drill and operate in the future in these two sections.

The remainder of our acreage in the core area of the Haynesville shale play, about 4,300 net acres, is operated by other companies. Just over half of our non-operated Haynesville acreage in this area of the play results from a transaction with a subsidiary of Chesapeake in July 2008. The remainder of our non-operated Haynesville acreage is attributable to leasehold interests that we hold in approximately 87 sections in Caddo, DeSoto, Bossier and Red River Parishes. Our working interests in the Haynesville wells in these sections range from less than 1% to more than 30%. At December 31, 2011, our production from these non-operated Haynesville wells averaged approximately 22 MMcfe per day.

We do not plan to drill any operated Haynesville wells in 2012, but we have budgeted capital expenditures of approximately $13 million for our anticipated participation in approximately 25 gross (1.5 net) non-operated wells that may be drilled in order to hold expiring acreage or that may be proposed in multi-well development programs to evaluate optimal well spacing.

Cotton Valley, Hosston (Travis Peak) and Other Shallower Formations

Prior to initiating natural gas production from the Haynesville shale in 2009, almost all of our production and reserves in northwest Louisiana and east Texas were attributable to wells producing from the Cotton Valley formation. We own almost all of the shallow rights from the base of the Cotton Valley formation to the surface under our acreage in northwest Louisiana and east Texas.

All of the shallow rights underlying our acreage in our Elm Grove/Caspiana properties in northwest Louisiana, approximately 10,000 gross and net acres at December 31, 2011, is held by existing production from the Cotton Valley formation or the Haynesville shale. The Cotton Valley formation was the primary producing zone in the Elm Grove field prior to discovery of the Haynesville shale. The Cotton Valley formation is a low permeability gas sand that ranges in thickness from 200 to 300 feet and has porosities ranging from 6% to 10%.

In January 2011, we completed our first horizontal Cotton Valley well, the Tigner Walker H #1-Alt. in our Elm Grove/Caspiana properties, in DeSoto Parish and commenced sales of natural gas from this well. Prior to this time, we had only drilled and completed vertical Cotton Valley and Hosston wells on these properties. During December 2011, this well produced at an average daily rate of approximately 1.6 MMcf of natural gas per day and through December 31, 2011, had produced a total of approximately 950 MMcf of natural gas. We are the operator and have a 100% working interest in this well. We have identified 60 gross and 36 net additional drilling locations for future Cotton Valley horizontal wells in our Elm Grove/Caspiana properties. We do not plan to drill any of these locations in 2012. As all of this acreage is held by existing production, we expect to allocate the majority of our near-term capital expenditures primarily to exploration and development of our Eagle Ford shale acreage in south Texas.

We also continue to hold the shallow rights by existing production or by leases that are still in their primary terms in our central and southwest Pine Island, Longwood, Woodlawn and other prospect areas in northwest Louisiana and east Texas. At December 31, 2011, we held an estimated 11,500 net leasehold and mineral acres by existing production in these areas.

Southwest Wyoming, Northeast Utah and Southeast Idaho — Meade Peak Shale

The Meade Peak shale is an organic-rich source rock that has sourced much of the oil and natural gas in conventional reservoirs in the western Wyoming and eastern Utah area. The Meade Peak shale has an observed shale thickness of 70 to 350 feet, total organic carbon of 3% to 7% and vitrinite reflectance values ranging from 1.8% to 2.7%. The Meade Peak shale is encountered at drill depths of 3,000 to 14,000 feet, with the majority of our acreage in the depth range of 3,000 to 10,000 feet. The shale has been penetrated by over 100 wells in the area, most of which have natural gas shows. Seismic and subsurface data show distinct, stacked thrust plates with areas of sediment prospective for natural gas.

At December 31, 2011, we had assembled approximately 144,000 gross, or approximately 136,000 net, acres in southwest Wyoming and adjacent areas in Utah and Idaho as part of a natural gas shale exploratory prospect targeting the Meade Peak shale. The majority of this acreage, with lease terms of five to ten years, has been acquired by us within the past four to five years, and we are the operator of this prospect.

We believe there have been no previous attempts to drill horizontally or to hydraulically fracture the Meade Peak shale in this area. Our focus to date has been to confirm the structure of the Meade Peak shale, understand its characteristics and evaluate its potential. We have gathered well log data in the area and studied the petrophysical characteristics. In addition, we have purchased 2-D seismic data and have worked with a structural geologist that has experience in the immediate area to better understand the area's tectonic history.

We have entered into a participation and joint operating agreement with other parties covering the initial exploration efforts and, if successful, the future development of this acreage. We began drilling the initial test well on this prospect, the Crawford Federal #1 well in Lincoln County, Wyoming, in February 2011. We reached a depth of 8,200 feet, approximately 300 feet above the top of the Meade Peak shale, before having operations suspended for several months due to wildlife restrictions. We resumed operations on this initial test well in September 2011 and completed drilling and coring operations on this well in November 2011. At December 31, 2011, this well had not been completed, as we were still evaluating the well logs and awaiting results from various core analysis tests.

Approximately 102,000 gross, or approximately 93,000 net, acres in this prospect are scheduled to expire at various times during 2012. Although we plan to seek extensions on some of this acreage, certain leases, particularly those taken on state lands, do not offer the opportunity for automatic extension, and we will be required to obtain new leases on these lands should we desire and be able to do so. We expect that a significant portion of the 93,000 net acres will be allowed to expire during 2012, while we and our partners continue to evaluate the results from our initial test well and plan for its completion and further testing. We have no production and no proved reserves attributable to this acreage at December 31, 2011.

Southeast New Mexico and West Texas — Delaware and Midland Basins

The Delaware and Midland Basins are mature exploration and production provinces with extensive developments in a wide variety of petroleum systems resulting in stacked target horizons in many areas. Historically, the majority of development in these basins has focused on relatively conventional reservoir targets, but we believe the combination of advanced formation evaluation, 3-D seismic technology, horizontal drilling and hydraulic fracturing technology is enhancing the development potential of these basins.

One example of such an opportunity appears to be the so-called "Wolf-Bone" play of the Delaware Basin. Together, the Lower Permian age Bone Spring (also called Leonardian) and Wolfcamp formations span several thousand feet of stacked shales, sandstones, limestones and dolomites representing complex and dynamic submarine depositional systems that include several organic rich source rocks. Throughout these intervals, oil and natural gas have been produced primarily from conventional sandstone and carbonate reservoirs even though hydrocarbons are trapped in the tight sands, limestones and dolomites interbedded within organic rich shale. Recently, these hydrocarbon-bearing zones have been recognized by a number of operators as targets for horizontal drilling and multi-stage hydraulic fracturing techniques. As a result, several large industry players are expanding positions and conducting drilling programs throughout Lea and Eddy Counties in southeast New Mexico and Loving, Reeves and Ward Counties in west Texas.

Although the Delaware and Midland Basins have not been a primary focus of our recent operations or exploration efforts, we were developing new oil and natural gas prospects in these basins at December 31, 2011. Most notably, we have identified potential drilling opportunities on our acreage, particularly in southeast New Mexico, near old vertical wells, some of which have produced up to 1,000,000 BOE from the Wolfcamp formation and up to 500,000 BOE from the Bone Spring formation. These wells suggest a hydrocarbon-rich environment in the area of our acreage, and after completing our internal geologic studies, we may determine to drill a Wolfcamp or Bone Spring vertical well or to drill a horizontal well to test these formations on our acreage.

At December 31, 2011, we had not included any potential drilling locations on our acreage in our total identified drilling locations, and we had not budgeted any capital expenditures to drill wells in southeast New Mexico or west Texas during 2012. We have budgeted $20.0 million of our anticipated 2012 capital expenditures to acquire additional leasehold interests primarily prospective for oil and liquids production in areas of southeast New Mexico and west Texas where we are developing new prospects. Although we do have existing leasehold interests in this area of approximately 11,000 gross and approximately 7,000 net acres at December 31, 2011, we believe approximately 8,000 gross and 4,000 net acres are no longer prospective, and we plan to let them expire without drilling.

Operating Summary

The following table sets forth certain unaudited production data for the years ended December 31, 2011, 2010 and 2009:

	Year Ended December 31, 2011	2010	2009
Unaudited Production Data			
Net Production Volumes:			
Oil (MBbls)	154	33	30
Natural gas (Bcf)	14.5	8.4	4.8
Total natural gas equivalents (Bcfe)(1)	15.4	8.6	5.0
Average daily production (MMcfe/d)(1)	42.3	23.6	13.7
Average Sales Prices:			
Oil (per Bbl)	$93.80	$76.39	$57.72
Natural gas, with realized derivatives (per Mcf)	$ 4.11	$ 4.38	$ 5.17
Natural gas, without realized derivatives (per Mcf)	$ 3.62	$ 3.75	$ 3.59
Operating Expenses (per Mcfe):			
Production taxes and marketing	$ 0.41	$ 0.23	$ 0.22
Lease operating	$ 0.47	$ 0.61	$ 0.94
Depletion, depreciation and amortization	$ 2.06	$ 1.81	$ 2.15
General and administrative	$ 0.87	$ 1.13	$ 1.42

(1) Estimated using a conversion ratio of one Bbl per six Mcf.

The following table sets forth information regarding our average net daily production and total production for the year ended December 31, 2010 from our primary operating areas:

	Average Net Daily Production: Gas (Mcf/d)	Oil (Bbls/d)	Gas Equivalent (Mcfe/d)	Total Net Production (MMcfe)	Percentage of Total Net Production
South Texas:					
Eagle Ford	4	19	119	43	0.5%
Austin Chalk(1)	–	–	–	–	–
Area Total	4	19	119	43	0.5
NW Louisiana/E Texas:					
Haynesville	17,127	1	17,132	6,253	72.7
Cotton Valley(2)	5,840	40	6,074	2,218	25.8
Area Total	22,967	41	23,206	8,471	98.5
SW Wyoming, NE Utah, SE Idaho(1)	–	–	–	–	–
SE New Mexico, West Texas	43	31	228	83	1.0
Total	23,014	91	23,553	8,597	100.0%

(1) We currently have no production from our acreage in southwest Wyoming and adjacent areas of Utah and Idaho and insignificant production from the Austin Chalk formation in south Texas.

(2) Includes the Cotton Valley formation and shallower zones and also includes one well producing from the Frio formation in Orange County, Texas and two wells producing from the San Miguel formation in Zavala County, Texas.

The following table sets forth information regarding our average net daily production and total production for the year ended December 31, 2011 from our primary operating areas:

	Average Net Daily Production			Total Net Production (MMcfe)	Percentage of Total Net Production
	Gas (Mcf/d)	Oil (Bbls/d)	Gas Equivalent (Mcfe/d)		
South Texas:					
Eagle Ford	1,298	331	3,286	1,200	7.8%
Austin Chalk(1)	–	–	–	–	–
Area Total	1,298	331	3,286	1,200	7.8
NW Louisiana/E Texas:					
Haynesville	32,319	–	32,319	11,797	76.4
Cotton Valley(2)	6,084	64	6,465	2,360	15.3
Area Total	38,403	64	38,784	14,157	91.7
SW Wyoming, NE Utah, SE Idaho(1)	–	–	–	–	–
SE New Mexico, West Texas	59	27	221	81	0.5
Total	39,760	422	42,291	15,438	100.0%

(1) We currently have no production from our acreage in southwest Wyoming and adjacent areas of Utah and Idaho and insignificant production from the Austin Chalk formation in south Texas.

(2) Includes the Cotton Valley formation and shallower zones and also includes one well producing from the Frio formation in Orange County, Texas and two wells producing from the San Miguel formation in Zavala County, Texas.

Our total production of 15.4 Bcfe for the year ended December 31, 2011 was an increase of 79% over our total production of 8.6 Bcfe for the year ended December 31, 2010. This increased production was primarily due to drilling operations in the Haynesville shale, but a portion of the increase also reflects production due to our initial drilling operations in the Eagle Ford shale. Our total production of 8.6 Bcfe for the year ended December 31, 2010 was an increase of 72% over our total production of 5.0 Bcfe for the year ended December 31, 2009. Most of this increase was attributable to our drilling operations in the Haynesville shale play. In addition, as a result of production from new wells that were completed in 2011, our daily production for the year ended December 31, 2011 averaged approximately 42.3 MMcfe per day, as compared to 23.6 MMcfe per day for the year ended December 31, 2010. Our daily oil production for the year ended December 31, 2011 averaged 422 Bbls per day, an approximate five-fold increase from 91 Bbls per day for the year ended December 31, 2010.

Producing Wells

The following table sets forth information relating to producing wells at December 31, 2011. Wells are classified as oil or natural gas according to their predominant production stream. We do not have any currently active dual completions. We have an approximate average working interest of 92% in all wells that we operate. For wells where we are not the operator, our working interests range from less than 1% to as much as 44%, and average approximately 9%. In the table below, gross wells are the total number of producing wells in which we own a working interest, and net wells represent the total of our fractional working interests owned in the gross wells.

	Natural Gas Wells		Oil Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
South Texas:						
Eagle Ford	2.0	2.0	7.0	5.3	9.0	7.3
Austin Chalk(1)	–	–	–	–	–	–
Area Total	2.0	2.0	7.0	5.3	9.0	7.3
NW Louisiana/E Texas:						
Haynesville	106.0	11.6	–	–	106.0	11.6
Cotton Valley(2)	106.0	69.7	2.0	2.0	108.0	71.7
Area Total	212.0	81.3	2.0	2.0	214.0	83.3
SW Wyoming, NE Utah, SE Idaho(1)	–	–	–	–	–	–
SE New Mexico, West Texas	1.0	0.6	12.0	5.1	13.0	5.7
Total	215.0	83.9	21.0	12.4	236.0	96.3

(1) We currently have no producing wells on our acreage in southwest Wyoming and adjacent areas of Utah and Idaho and insignificant production from the Austin Chalk formation in south Texas.

(2) Includes shallower zones and also includes one well producing from the Frio formation in Orange County, Texas and two wells producing from the San Miguel formation in Zavala County, Texas.

Estimated Proved Reserves

The following table sets forth our estimated proved oil and natural gas reserves at December 31, 2011, 2010 and 2009. The reserves estimates were based on evaluations prepared by our engineering staff and have been audited for their reasonableness by Netherland, Sewell & Associates, Inc., independent reservoir engineers. These reserves estimates were prepared in accordance with the SEC's rules for oil and natural gas reserves reporting. The estimated reserves shown are for proved reserves only and do not include any unproved reserves classified as probable or possible reserves that might exist for our properties, nor do they include any consideration that could be attributable to interests in unproved and unevaluated acreage beyond those tracts for which proved reserves have been estimated. Proved oil and natural gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Our total estimated proved reserves are estimated using a conversion ratio of one Bbl per six Mcf.

	At December 31,(1)		
	2011	2010	2009
Estimated Proved Reserves Data:(2)			
Estimated proved reserves:			
Oil (MBbls)	3,794	152	103
Natural Gas (Bcf)	170.4	127.4	63.9
Total (Bcfe)	193.2	128.3	64.5
Estimated proved developed reserves:			
Oil (MBbls)	1,419	152	103
Natural Gas (Bcf)	56.5	43.1	25.4
Total (Bcfe)	65.1	44.1	26.0
Percent developed	33.7%	34.3%	40.3%
Estimated proved undeveloped reserves:			
Oil (MBbls)	2,375	–	–
Natural Gas (Bcf)	113.9	84.3	38.6
Total (Bcfe)	128.1	84.3	38.6
PV-10(3) (in millions)	$248.7	$119.9	$70.4
Standardized Measure(4) (in millions)	$215.5	$111.1	$65.1

(1) Numbers in table may not total due to rounding.

(2) Our estimated proved reserves, PV-10 and Standardized Measure were determined using index prices for oil and natural gas, without giving effect to derivative transactions, and were held constant throughout the life of the properties. The unweighted arithmetic averages of the first-day-of-the-month prices for the 12 months ended December 31, 2009 were $57.65 per Bbl for oil and $3.866 per MMBtu for natural gas, for the 12 months ended December 31, 2010 were $75.96 per Bbl for oil and $4.376 per MMBtu for natural gas, and for the 12 months ended December 31, 2011 were $92.71 per Bbl for oil and $4.118 per MMBtu for natural gas. These prices were adjusted by lease for quality, energy content, regional price differentials, transportation fees, marketing deductions and other factors affecting the price received at the wellhead.

(3) PV-10 is a non-GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. PV-10 is not an estimate of the fair market value of our properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies and of the potential return on investment related to the companies' properties without regard to the specific tax characteristics of such entities. Our PV-10 at December 31, 2009, 2010 and 2011 may be reconciled to our Standardized Measure of discounted future net cash flows at such dates by reducing our PV-10 by the discounted future income taxes associated with such reserves. The discounted future income taxes at December 31, 2009, 2010 and 2011 were, in millions, $5.3, $8.8 and $33.2, respectively.

(4) Standardized Measure represents the present value of estimated future net cash flows from proved reserves, less estimated future development, production, plugging and abandonment costs and income tax expenses, discounted at 10% per annum to reflect the timing of future cash flows. Standardized Measure is not an estimate of the fair market value of our properties.

Our total proved oil and natural gas reserves increased from 128.3 Bcfe at December 31, 2010 to 193.2 Bcfe at December 31, 2011. Most of this increase is attributable to proved reserves added due to our drilling operations in both the Eagle Ford and Haynesville shale plays. The increase in proved oil reserves specifically from 152 MBbls at December 31, 2010 to 3,794 MBbls at December 31, 2011 is attributable to proved oil reserves added due to our drilling operations in the Eagle Ford shale play. Our proved reserves at December 31, 2011 were made up of approximately 88% natural gas and 12% oil. Our proved developed reserves increased from 44.1 Bcfe at December 31, 2010 to 65.1 Bcfe at December 31, 2011 due primarily to proved developed reserves added as a result of drilling operations in both the Eagle Ford and Haynesville shale plays. The increase in proved developed oil reserves specifically from 152 MBbls at December 31, 2010 to 1,419 MBbls at December 31, 2011 is attributable to proved developed oil reserves added due to our drilling operations in the Eagle Ford shale play. Our proved undeveloped reserves increased from 84.3 Bcfe at December 31, 2010 to 128.1 Bcfe at December 31, 2011 due primarily to our drilling operations in the Eagle Ford and Haynesville shale plays. The increase in our proved undeveloped oil reserves specifically from zero to 2,375 MBbls at December 31, 2011 is attributable to our drilling operations in the Eagle Ford shale play. The net increase of 43.8 Bcfe in our proved undeveloped reserves from December 31, 2010 to December 31, 2011 is composed of (1) additions of 49.0 Bcfe to proved undeveloped reserves identified through drilling operations, less (2) the conversion of 3.4 Bcfe of proved undeveloped reserves to proved developed reserves, less (3) the downward revisions of proved undeveloped reserves by 1.8 Bcfe in the period. During this period, we recorded no changes to proved undeveloped reserves as a result of the acquisition or divestment of reserves. At December 31, 2011, we had no proved reserves in our estimates that remained undeveloped for five years or more following their initial booking.

The following table sets forth additional summary information by operating area with respect to our estimated proved reserves at December 31, 2011:

	Net Proved Reserves[(1)]				
	Oil	**Gas**	**Gas Equivalent**	**PV-10[(2)]**	**Standardized Measure[(3)]**
	(MBbls)	**(Bcf)**	**(Bcfe)**	**(in millions)**	**(in millions)**
South Texas:					
Eagle Ford	3,636	6.1	27.9	$130.2	$112.8
Austin Chalk[(4)]	–	–	–	–	–
Area Total	3,636	6.1	27.9	130.2	112.8
NW Louisiana/E Texas:					
Haynesville	–	150.4	150.4	96.6	83.7
Cotton Valley[(5)]	61	13.8	14.2	19.5	16.9
Area Total	61	164.2	164.6	116.1	100.6
SW Wyoming, NE Utah, SE Idaho[(4)]	–	–	–	–	–
SE New Mexico, West Texas	97	0.1	0.7	2.4	2.1
Total	3,794	170.4	193.2	$248.7	$215.5

(1) Numbers in table may not total due to rounding.

(2) PV-10 is a non-GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. PV-10 is not an estimate of the fair market value of our properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies and of the potential return on investment related to the companies' properties without regard to the specific tax characteristics of such entities. Our PV-10 at December 31, 2011 may be reconciled to our Standardized Measure of discounted future net cash flows at such date by reducing our PV-10 by the discounted future income taxes associated with such reserves. The discounted future income taxes at December 31, 2011 were approximately $33.2 million.

(3) Standardized Measure represents the present value of estimated future net cash flows from proved reserves, less estimated future development, production, plugging and abandonment costs and income tax expenses, discounted at 10% per annum to reflect the timing of future cash flows. Standardized Measure is not an estimate of the fair market value of our properties.

(4) At December 31, 2011, we had no proved reserves attributable to the Austin Chalk formation in south Texas or to our acreage in southwest Wyoming and adjacent areas of Utah and Idaho.

(5) Includes Cotton Valley and shallower zones and also includes one well producing from the Frio formation in Orange County, Texas and two wells producing from the San Miguel formation in Zavala County, Texas.

Technology Used to Establish Reserves

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

In order to establish reasonable certainty with respect to our estimated proved reserves, we used technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and technical data used in the estimation of our proved reserves include, but are not limited to, electric logs, radioactivity logs, core analyses, geologic maps and available downhole and production data, seismic data and well test data. Reserves for proved developed producing wells were estimated using production performance and material balance methods. Certain new producing properties with little production history were forecast using a combination of production performance and analogy to offset production. Non-producing reserves estimates for both developed and undeveloped properties were forecast using either volumetric and/or analogy methods.

Internal Control Over Reserves Estimation Process

We maintain an internal staff of petroleum engineers and geoscience professionals to ensure the integrity, accuracy and timeliness of the data used in our reserves estimation process. Our Reserves Manager is primarily responsible for overseeing the preparation of our reserves estimates and has over 15 years of industry experience. Our Reserves Manager received his Ph.D. degree in Petroleum Engineering from Texas A&M University, is a Licensed Professional Engineer in the State of Texas and received a certificate of completion in a prescribed course of study in Reserves and Evaluation from Texas A&M University in May 2009. Our Vice President – Reservoir Engineering is responsible for reviewing and approving our reserves estimates and has over 30 years of industry experience. Following the preparation of our reserves estimates, we had our reserves estimates audited for their reasonableness by Netherland, Sewell & Associates, Inc., our independent petroleum engineers. The Engineering Committee of our board of directors reviews the reserves report and our reserves estimation process, and the results of the reserves report and the independent audit of our reserves are reviewed by members of our board of directors, including members of our Audit Committee.

Acreage Summary

The following table sets forth the approximate acreage in which we held a leasehold, mineral or other interest at December 31, 2011. At that date, only about 12% of our total acreage had been developed, although these percentages are much higher in northwest Louisiana and east Texas.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
South Texas:						
Eagle Ford	2,514	2,130	48,225	26,543	50,739	28,673
Austin Chalk	–	–	24,473	14,849	24,473	14,849
Area Total(1)	2,514	2,130	48,225	26,543	50,739	28,673
NW Louisiana/E Texas:						
Haynesville	18,713	10,599	4,158	3,928	22,871	14,527
Cotton Valley(2)	20,942	17,846	5,327	5,208	26,269	23,054
Area Total(3)	23,033	19,691	5,866	5,648	28,899	25,339
SW Wyoming, NE Utah, SE Idaho	–	–	144,368	135,862	144,368	135,862
SE New Mexico, West Texas	1,160	1,038	9,554	5,620	10,714	6,658
Total	26,707	22,859	208,013	173,673	234,720	196,532

(1) Some of the same leases cover the net acres shown for the Eagle Ford shale and the Austin Chalk formation, a shallower formation than the Eagle Ford shale. Consequently, the total acreage will not equal the sum of the acreage by operating area.

(2) Includes shallower zones and also includes acreage surrounding one well producing from the Frio formation in Orange County, Texas.

(3) Some of the same leases cover the net acres shown for the Haynesville formation and the Cotton Valley formation, a shallower formation than the Haynesville shale. Consequently, the total acreage will not equal the sum of the acreage by operating area.

Undeveloped Acreage Expiration

The following table sets forth the approximate number of gross and net undeveloped acres at December 31, 2011 that will expire prior to December 31, 2013 by operating area unless production is established within the spacing units covering the acreage prior to the expiration dates or unless the existing leases are renewed prior to expiration:

	Acres Expiring 2012		Acres Expiring 2013	
	Gross	Net	Gross	Net
South Texas:				
Eagle Ford	15,044	4,349	12,165	7,149
Austin Chalk	5,731	1,133	3,851	2,646
Area Total(1)	15,044	4,349	12,165	7,149
NW Louisiana/E Texas				
Haynesville	644	395	40	5
Cotton Valley	750	401	40	5
Area Total(2)	750	401	40	5
SW Wyoming, NE Utah, SE Idaho	101,905	93,356	8,461	8,301
SE New Mexico, West Texas	1,712	79	8,454	2,715
Total	119,411	98,185	29,120	18,170

(1) Some of the same leases cover the net acres shown for the Eagle Ford shale and the Austin Chalk formation, a shallower formation than the Eagle Ford shale. Consequently, the total acreage will not equal the sum of the acreage by operating area.

(2) Some of the same leases cover the net acres shown for the Haynesville shale and the Cotton Valley formation, a shallower formation than the Haynesville shale. Consequently, the total acreage will not equal the sum of the acreage by operating area.

Many of the leases comprising the acreage set forth in the table above will expire at the end of their respective primary terms unless production from the acreage has been established prior to such date, in which event the lease will remain in effect until the cessation of production in commercial quantities. We also have options to extend some of our leases through payment of additional lease bonus payments prior to the expiration of the primary term of the leases. In addition, we may attempt to secure a new lease upon the expiration of certain of our acreage; however, there may be third party leases that become effective immediately if our leases expire at the end of their respective terms and production has not been established prior to such date. Our leases are mainly fee leases with three to five years of primary term. We believe that our lease terms are similar to our competitors' fee lease terms as they relate to both primary term and royalty interests.

Drilling Results

The following table summarizes our drilling activity for the three years ended December 31, 2011, 2010 and 2009:

	Year Ended December 31,					
	2011		2010		2009	
	Gross	Net	Gross	Net	Gross	Net
Development Wells						
Productive	30	0.6	5	1.7	3	1.3
Dry	–	–	–	–	–	–
Exploration Wells						
Productive	30	10.2	36	3.4	15	6.0
Dry	–	–	–	–	2	2.0
Total Wells						
Productive	60	10.8	41	5.1	18	7.3
Dry	–	–	–	–	2	2.0

Marketing

Our crude oil is generally sold under short-term, extendable and cancellable agreements with unaffiliated purchasers based on published price bulletins reflecting an established field posting price. As a consequence, the prices we receive for crude oil and liquids move up and down in direct correlation with the oil market as it reacts to supply and demand factors. Transportation costs related to moving crude oil are also deducted from the price received for crude oil.

Our natural gas is sold under both long-term and short-term natural gas purchase agreements. Natural gas produced by us is sold at various delivery points at or near producing wells to both unaffiliated independent marketing companies and unaffiliated mid-stream companies. We receive proceeds from prices that are based on various pipeline indices less any associated fees. When there is an opportunity to do so, the mid-stream companies may, at our request, process our natural gas at a processing facility and extract liquid hydrocarbons from the natural gas. We are then paid for the extracted liquids based on a negotiated percentage of the proceeds that are generated from the mid-stream companies' sale of the liquids, or based on other negotiated pricing arrangements.

The prices we receive for our oil and natural gas production fluctuate widely. Factors that cause price fluctuations include the level of demand for oil and natural gas, weather conditions, hurricanes in the Gulf Coast region, natural gas storage levels, domestic and foreign governmental regulations, the actions of OPEC, price and availability of alternative fuels, political conditions in oil and natural gas producing regions, the domestic and foreign supply of oil and natural gas, the price of foreign imports and overall economic conditions. Decreases in these commodity prices do adversely affect the carrying value of our proved reserves and our revenues, profitability and cash flows. Short-term disruptions of our oil and natural gas production do occur from time to time due to downstream pipeline system failure, capacity issues and scheduled maintenance, as well as maintenance and repairs involving our own well operations. These situations do curtail our production capabilities and ability to maintain a steady source of revenue for our company. In addition, demand for natural gas has historically been seasonal in nature, with peak demand and typically higher prices during the colder winter months. See "Risk Factors — Our Success Is Dependent on the Prices of Oil and Natural Gas. Low Oil or Natural Gas Prices and the Substantial Volatility in These Prices May Adversely Affect Our Financial Condition and Our Ability to Meet Our Capital Expenditure Requirements and Financial Obligations."

For the year ended December 31, 2009, we had three significant purchasers that each accounted for more than 10% of our total oil and natural gas revenues: Chesapeake Operating Inc. (32%), Regency Gas Services LP (25%), and J-W Operating Company (17%). For the year ended December 31, 2010, we had three significant purchasers that each accounted for more than 10% of our total oil and natural gas revenues: Chesapeake Operating Inc. (42%), Regency Gas Services LP (17%) and Petrohawk Energy Corporation (11%). For the year ended December 31, 2011, we had three significant purchasers that each accounted for more than 10% of our total oil and natural gas revenues: Sequent Energy Management (24%), Chesapeake Operating Inc. (21%) and Eastex Crude Company (15%). Due to the nature of the markets for oil and natural gas, we do not believe that the loss of any one of these purchasers would have a material adverse impact on our financial condition, results of operations or cash flows for any significant period of time.

While we do not have any commitments to sell a fixed and determinable quantity of oil or natural gas to a particular buyer, we were party to two natural gas transportation agreements at December 31, 2011 that require us to deliver a specified volume of natural gas through pipelines for a fixed period of time. If we fail to meet the volume requirements, we are required to pay an amount to the owners of the pipelines to offset a portion of the expenses they incurred in building the pipelines to our well locations. Neither of these contracts constitutes a material commitment.

Title to Properties

We endeavor to assure that title to our properties is in accordance with standards generally accepted in the oil and natural gas industry. Some of our acreage will be obtained through farmout agreements, term assignments and other contractual arrangements with third parties, the terms of which often will require the drilling of wells or the undertaking of other exploratory or development activities in order to retain our interests in the acreage. Our title to these contractual interests will be contingent upon our satisfactory fulfillment of these obligations. Our properties are also subject to customary royalty interests, liens incident to financing arrangements, operating agreements, taxes and other burdens that we believe will not materially interfere with the use and operation of or affect the value of these properties. We intend to maintain our leasehold interests by making lease rental payments or by producing wells in paying quantities prior to expiration of various time periods to avoid lease termination. Certain of the leases that we have obtained to date have been purchased by and in the name of professional lease brokers as our nominee. See "Risk Factors — We May Incur Losses or Costs as a Result of Title Deficiencies in the Properties in Which We Invest."

Competition

The oil and natural gas industry is highly competitive. We compete and will continue to compete with major and independent oil and natural gas companies for exploration opportunities, acreage and property acquisitions. We also compete for drilling rig contracts and other equipment and labor required to drill, operate and develop our properties. Most of our competitors have substantially greater financial resources, staffs, facilities and other resources. In addition, larger competitors may be able to absorb the burden of any changes in federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position. These competitors may be able to pay more for drilling rigs or exploratory prospects and productive oil and natural gas properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than we can. Our competitors may also be able to afford to purchase and operate their own drilling rigs.

Our ability to drill and explore for oil and natural gas and to acquire properties will depend upon our ability to conduct operations, to evaluate and select suitable properties and to consummate transactions in this highly competitive environment. We have been conducting field operations since 2004 while our competitors have a longer history of operations, and most of them have also demonstrated the ability to operate through industry cycles.

The oil and natural gas industry also competes with other energy-related industries in supplying the energy and fuel requirements of industrial, commercial and individual consumers. See "Risk Factors – Competition in the Oil and Natural Gas Industry Is Intense Making It More Difficult for Us to Acquire Properties, Market Natural Gas and Secure Trained Personnel."

Regulation

Oil and Natural Gas Regulation

Our oil and natural gas exploration, development, production and related operations are subject to extensive federal, state and local laws, rules and regulations. Failure to comply with these laws, rules and regulations can result in substantial penalties. The regulatory burden on the oil and natural gas industry increases our cost of doing business and affects our profitability. Because these rules and regulations are frequently amended or reinterpreted and new rules and regulations are promulgated, we are unable to predict the future cost or impact of complying with the laws, rules and regulations to which we are, or will become, subject. Our competitors in the oil and natural gas industry are generally subject to the same regulatory requirements and restrictions that affect our operations. We cannot predict the impact of future government regulation on our properties or operations.

Texas, New Mexico, Louisiana, Wyoming, Idaho and Utah and many other states require permits for drilling operations, drilling bonds and reports concerning operations and impose other requirements relating to the exploration, development and production of oil and natural gas. Many states also have statutes or regulations addressing conservation of oil and natural gas matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum rates of production from wells, the regulation of well spacing, the surface use and restoration of properties upon which wells are drilled, the sourcing and disposal of water used in the drilling and completion process and the plugging and abandonment of these wells. Many states restrict production to the market demand for oil and natural gas. Some states have enacted statutes prescribing ceiling prices for natural gas sold within their boundaries. Additionally, some regulatory agencies have, from time to time, imposed price controls and limitations on production by restricting the rate of flow of oil and natural gas wells below natural production capacity in order to conserve supplies of oil and natural gas. 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.

Some of our oil and natural gas leases are issued by agencies of the federal government, as well as agencies of the states in which we operate. These leases contain various restrictions on access and development and other requirements that may impede our ability to conduct operations on the acreage represented by these leases.

Our sales of natural gas, as well as the revenues we receive from our sales, are affected by the availability, terms and costs of transportation. The rates, terms and conditions applicable to the interstate transportation of natural gas by pipelines are regulated by the Federal Energy Regulatory Commission, or FERC, under the Natural Gas Act of 1938, or the NGA, as well as under Section 311 of the Natural Gas Policy Act of 1978, or the NGPA. Since 1985, FERC has implemented regulations intended to increase competition within the natural gas industry by making natural gas transportation more accessible to natural gas buyers and sellers on an open-access, non-discriminatory basis. The natural gas industry has historically, however, been heavily regulated and we can give no assurance that the current less stringent regulatory approach of FERC will continue.

In 2005, Congress enacted the Domenici-Barton Energy Policy Act of 2005, or the Energy Policy Act. The Energy Policy Act, among other things, amended the NGA to prohibit market manipulation by any entity, to direct FERC to facilitate market transparency in the market for sale or transportation of physical natural gas in interstate commerce, and to significantly increase the penalties for violations of the NGA, the NGPA, or FERC rules, regulations or orders thereunder. FERC has promulgated regulations to implement the Energy Policy Act. Should we violate the anti-market manipulation laws and related regulations, in addition to FERC-imposed penalties, we may also be subject to third party damage claims.

Intrastate natural gas transportation is 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. Because these regulations will apply to all intrastate natural gas shippers within the same state on a comparable basis, we believe that the regulation in any states in which we operate will not affect our operations in any way that is materially different from our competitors that are similarly situated.

The price we receive from the sale of oil and natural gas liquids will be affected by the availability, terms and cost of transportation of the products to market. Under rules adopted by FERC, interstate oil pipelines can change rates based on an inflation index, though other rate mechanisms may be used in specific circumstances. Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions, which varies from state to state. We are not able to predict with certainty the effects, if any, of these regulations on our operations.

In 2007, the Energy Independence & Security Act of 2007, or the EISA, went into effect. The EISA, among other things, prohibits market manipulation by any person in connection with the purchase or sale of crude oil, gasoline or petroleum distillates at wholesale in contravention of such rules and regulations that the Federal Trade Commission may prescribe, directs the Federal Trade Commission to enforce the regulations and establishes penalties for violations thereunder. We cannot predict any future regulations or their impact.

U.S. Federal and State Taxation

The federal, state and local governments in the areas in which we operate impose taxes on the oil and natural gas products we sell and, for many of our wells, sales and use taxes on significant portions of our drilling and operating costs. In the past, there has been a significant amount of discussion by legislators and presidential administrations concerning a variety of energy tax proposals. President Obama has recently proposed sweeping changes in federal laws on the income taxation of small oil and natural gas exploration and production companies such as us. President Obama has proposed to eliminate allowing small U.S. oil and natural gas companies to deduct intangible drilling costs as incurred and percentage depletion. Many states have raised state taxes on energy sources, and additional increases may occur. Changes to tax laws could adversely affect our business and our financial results. See "Risk Factors — We Are Subject to Federal, State and Local Taxes, and May Become Subject to New Taxes or Have Eliminated or Reduced Certain Federal Income Tax Deductions Currently Available with Respect to Oil and Natural Gas Exploration and Production Activities as a Result of Future Legislation, Which Could Adversely Affect Our Business, Financial Condition, Results of Operations and Cash Flows."

Hydraulic Fracturing Policies and Procedures

We use hydraulic fracturing as a means to maximize the productivity of our oil and natural gas wells in almost every well that we drill and complete. Our engineers responsible for these operations attend specialized hydraulic fracturing training programs taught by industry professionals. Although average drilling and completion costs for each area will vary, as will the cost of each well within a given area, on average approximately 50% of the drilling and completion costs for our horizontal wells are associated with hydraulic fracturing activities. These costs are treated in the same way that all other costs of drilling and completion of our wells are treated and are built into and funded through our normal capital expenditures budget. A change to any federal and state laws and regulations governing hydraulic fracturing could impact these costs and adversely affect our business and financial results. See "Risk Factors — Federal and State Legislation and Regulatory Initiatives Relating to Hydraulic Fracturing Could Result in Increased Costs and Additional Operating Restrictions or Delays."

The protection of groundwater quality is important to us. We believe that we follow all state and federal regulations and apply industry standard practices for groundwater protection in our operations. These measures are subject to close supervision by state and federal regulators (including the BLM with respect to federal acreage). Our policy and practice is to follow all applicable guidelines and regulations in the areas where we conduct hydraulic fracturing. A surface casing string is typically set deeper than the deepest usable quality fresh water zones and cemented back to the surface in accordance with the appropriate regulations, lease requirements and legal requirements. This surface string of casing is then pressure tested to ensure mechanical integrity of the casing string prior to continuing drilling operations. We follow strict quality control procedures for conducting hydraulic fracturing operations that include a multi-point safety checklist, managing inventories of all materials and chemicals on the well site and ensuring that Material Safety Data Sheets are on location for every well that is hydraulically fractured. We contract with third parties to conduct hydraulic fracturing operations, and we send at least one of our own engineers or an experienced consultant to the well site to personally supervise each hydraulic fracture treatment. On a real-time basis, we closely monitor pump rates and pressures on existing casing strings to ensure that wellbore integrity is maintained during hydraulic fracturing operations. Our policy regarding monitoring well pressures would require stopping the hydraulic fracturing operations upon any indication that wellbore integrity may have been compromised.

We follow additional regulatory requirements and recommended practices to ensure wellbore integrity and full isolation of any underground aquifers and protection of surface waters. These include the following:

- Prior to perforating the production casing and hydraulic fracturing operations, a cement bond log is run to verify cement integrity between the formation to be fractured and shallow formations. Then, the casing is pressure tested to ensure no leaks exist within the casing;

- Before the fracturing operation commences, all surface equipment is pressure tested, which includes the wellhead and all high pressure lines and connections leading from the pumping equipment to the wellhead. During the pumping phases of the hydraulic fracturing treatment, the service companies we engage must provide specialized equipment to monitor and record surface pressures, pumping rates, volumes and chemical concentrations to ensure the treatment is proceeding as designed and the wellbore integrity is sound. Our engineers at the job site have laptop computers with special software to monitor and collect, for permanent archiving, information from the hydraulic fracturing operations. As part of this process, when fracturing operations are being performed down casing, we also monitor the casing annular pressure to ensure that there is no communication of hydraulic pressure and fracture fluids outside the casing that could communicate with shallow formations. Should any problem be detected at any time during the hydraulic fracturing treatment, the operation would be shut down until the problem is evaluated, reported and remediated; and
- As a means to further protect against the negative impacts of any potential surface release of fluids associated with the hydraulic fracturing operation, special precautions are taken both during and after the operation. During the fracturing operation, all chemicals are mixed into the fracturing fluid as it is being pumped into the well as opposed to being pre-mixed in the "frac pits" or work tanks. While chemical additives are stored on location in independent containment vessels, only fresh water is stored in the frac pits or work tanks. All pumping equipment used during the operation is pressure tested and monitored. When the well is flowed back, after the fracturing operation, all fluids are produced into closed-top storage tanks. All flowback equipment and piping are pressure tested to ensure no leaks are present and the fluids are properly contained.

Once the final string of casing is set in place, cement is pumped into the casing/wellbore annulus where it hardens and creates a permanent, isolating barrier between the steel casing pipe and surrounding geological formations. This aspect of the well design establishes a pressure seal essentially eliminating any pathway for the fracturing fluid to contact fresh water aquifers during the hydraulic fracturing operation. Furthermore, in the areas in which we conduct hydraulic fracturing, the hydrocarbon bearing formations are separated from any usable quality underground fresh water aquifers by thousands of feet of impermeable rock layers. This natural geological separation serves as a protective barrier, preventing migration of fracturing fluids or hydrocarbons upwards into any fresh water zones.

Although rare, if and when the cement and steel casing used in well construction need to be remediated, we deal with these problems by evaluating the issue, running diagnostic tools including cement bond logs, temperature logs and pressure testing, followed by pumping remedial cement jobs. We repair wellhead leaks by replacing wellhead components, re-installing components to proper specifications and re-testing. In wellbores that utilize downhole packers, pressure integrity issues are rectified by repairing or replacing packers. Casing integrity lost due to corrosion on a producing well is remedied by identifying the specific location of the leak by cased hole logging tools, mechanical isolation and pressure testing or other diagnostic methods, followed by high pressure squeeze cementing and subsequent pressure testing to ensure the leak has been repaired. Throughout the process we believe we abide by applicable regulations.

The vast majority of hydraulic fracturing treatments are made up of water and sand or other kinds of man-made propping agents. We use major hydraulic fracturing service companies who track and report chemical additives that are used in the fracturing operation as required by the appropriate governmental agencies. These service companies fracture stimulate thousands of wells each year for the industry and invest millions of dollars to protect the environment through rigorous safety procedures, and also work to develop more environmentally friendly fracturing fluids. As previously mentioned, we also follow strict safety procedures and monitor all aspects of the fracturing operation to ensure environmental protection. We do not pump any diesel in the fluid systems of any of our fracture stimulation procedures.

While current fracture stimulation procedures utilize a significant amount of water, we typically recover less than 10% of this fracture stimulation water before produced salt water becomes a significant portion of the fluids produced. All produced water, including fracture stimulation water, is disposed of in a way that does not impact surface waters. All produced water is disposed of in permitted and regulated disposal facilities.

Environmental Regulation

The exploration, development and production of oil and natural gas, including the operation of salt water injection and disposal wells, are subject to various federal, state and local environmental laws and regulations. These laws and regulations can increase the costs of planning, designing, installing and operating oil and natural gas wells. Our activities are subject to a variety of environmental laws and regulations, including but not limited to: the Oil Pollution Act of 1990, or the OPA 90, the Clean Water Act, or the CWA, the Comprehensive Environmental Response, Compensation and Liability Act, or CERCLA, the Resource Conservation and Recovery Act, or RCRA, the Clean Air Act, or the CAA, the Safe Drinking Water Act, or the SDWA, and the Occupational Safety and Health Act, or OSHA, as well as comparable state statutes and regulations. We are also subject to regulations governing the handling, transportation, storage and disposal of wastes generated by our activities and naturally occurring radioactive materials, or NORM, that may result from our oil and natural gas operations. Civil and criminal fines and penalties may be imposed for noncompliance with these environmental laws and regulations. Additionally, these laws and regulations require the acquisition of permits or other governmental authorizations before undertaking some activities, limit or prohibit other activities because of protected wetlands, areas or species and require investigation and cleanup of pollution. We expect to remain in compliance in all material respects with currently applicable environmental laws and regulations and expect that these laws and regulations will not have a material adverse impact on us.

The OPA 90 and its regulations impose requirements on "responsible parties" related to the prevention of crude oil spills and liability for damages resulting from oil spills into or upon navigable waters, adjoining shorelines or in the exclusive economic zone of the United States. A "responsible party" under the OPA 90 may include the owner or operator of an onshore facility. The OPA 90 subjects responsible parties to strict, joint and several financial liability for removal costs and other damages, including natural resource damages, caused by an oil spill that is covered by the statute. It also imposes other requirements on responsible parties, such as the preparation of an oil spill contingency plan. Failure to comply with the OPA 90 may subject a responsible party to civil or criminal enforcement action. We may conduct operations on acreage located near, or that affects, navigable waters subject to the OPA 90. We believe that compliance with applicable requirements under the OPA 90 will not have a material and adverse effect on us.

The CWA and comparable state laws impose restrictions and strict controls regarding the discharge of produced waters, fill materials and other materials into navigable waters. These controls have become more stringent over the years, and it is possible that additional restrictions will be imposed in the future. Permits are required to discharge pollutants into certain state and federal waters and to conduct construction activities in those waters and wetlands. Certain state regulations and the general permits issued under the federal National Pollutant Discharge Elimination System program prohibit the discharge of produced water, produced sand, drilling fluids, drill cuttings and certain other substances related to the oil and natural gas industry into certain coastal and offshore waters. Further, the U.S. Environmental Protection Agency, or the EPA, has adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain permits for storm water discharges. Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans. The CWA and comparable state statutes provide for civil, criminal and administrative penalties for any unauthorized discharges of oil and other pollutants and impose liability for the costs of removal or remediation of contamination resulting from such discharges. In furtherance of the CWA, the EPA promulgated the Spill Prevention, Control, and Countermeasure regulations, which require certain oil-storing facilities to prepare plans and meet construction and operating standards.

CERCLA, also known as the "Superfund" law, and comparable state statutes impose liability, without regard to fault or the legality of the original conduct, on various classes of persons that are considered to have contributed to the release of a "hazardous substance" into the environment. These persons include the owner or operator of the disposal site where the release occurred and companies that disposed of, or arranged for the disposal of, the hazardous substances found at the site. Persons who are responsible for releases of hazardous substances under CERCLA may be subject to joint and several liability for the costs of cleaning up the hazardous substances and for damages to natural resources. 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 hazardous substances released into the environment. Although CERCLA generally exempts petroleum from the definition of hazardous substances, our operations may, and in all likelihood will, involve the use or handling of materials that may be classified as hazardous substances under CERCLA. Certain state statutes may not contain a similar exemption for petroleum. Furthermore, we may acquire or operate properties that unknown to us have been subjected to, or have caused or contributed to, prior releases of hazardous wastes.

RCRA and comparable state and local statutes govern the management, including treatment, storage and disposal, of both hazardous and nonhazardous solid wastes. We generate hazardous and nonhazardous solid waste in connection with our routine operations. At present, RCRA includes a statutory exemption that allows many wastes associated with crude oil and natural gas exploration and production to be classified as nonhazardous waste. A similar exemption is contained in many of the state counterparts to RCRA. Not all of the wastes we generate fall within these exemptions. At various times in the past, proposals have been made to amend RCRA to eliminate the exemption applicable to crude oil and natural gas exploration and production wastes. Repeal or modifications of this exemption by administrative, legislative or judicial process, or through changes in applicable state statutes, would increase the volume of hazardous waste we are required to manage and dispose of and would cause us, as well as our competitors, to incur increased operating expenses. Hazardous wastes are subject to more stringent and costly disposal requirements than are nonhazardous wastes.

The CAA, as amended, and comparable state laws restrict the emission of air pollutants from many sources, including oil and natural gas production. These laws and any implementing regulations impose stringent air permit requirements and require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions, or to use specific equipment or technologies to control emissions. On July 28, 2011, the EPA proposed new regulations targeting air emissions from the oil and natural gas industry. The proposed rules, if adopted, would impose new requirements on production and processing and transmission and storage facilities and on hydraulic fracturing activities. While we may be required to incur certain capital expenditures in the next few years for air pollution control equipment in connection with maintaining or obtaining operating permits addressing other air emission-related issues, we do not believe that such requirements will affect our operations in any way that is materially different from our competitors.

Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly waste handling, storage, transport, disposal, cleanup or operating requirements could materially adversely affect our operations and financial position, as well as those of the oil and natural gas industry in general. For instance, recent scientific studies have suggested that emissions of certain gases, commonly referred to as "greenhouse gases," and including carbon dioxide and methane, may be contributing to the warming of the Earth's atmosphere. As a result, there have been attempts to pass comprehensive greenhouse gas legislation. To date, such legislation has not been enacted. Any future federal laws or implementing regulations that may be adopted to address greenhouse gas emissions could, and in all likelihood would, require us to incur increased operating costs adversely affecting our profits and could adversely affect demand for the oil and natural gas we produce depressing the prices we receive for oil and natural gas.

The EPA has published its findings that emissions of greenhouse gases presented an endangerment to human health and the environment. These findings by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of greenhouse gases under existing provisions of the CAA. Subsequently, the EPA proposed and adopted two sets of regulations, one of which requires a reduction in emissions of greenhouse gases from motor vehicles and the other of which regulated emissions of greenhouse gases from certain large stationary sources. In addition, on October 30, 2009, the EPA published a rule requiring the reporting of greenhouse gas emissions from specified sources in the U.S. beginning in 2011 for emissions occurring in 2010. On November 30, 2010, the EPA released a rule that expands its final rule on greenhouse gas emissions reporting to include owners and operators of onshore and offshore oil and natural gas production, onshore natural gas processing, natural gas storage, natural gas transmission and natural gas distribution facilities. Reporting of greenhouse gas emissions from such onshore production will be required on an annual basis beginning in 2012 for emissions occurring in 2011. The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of greenhouse gases from, our equipment and operations could, and in all likelihood will, require us to incur costs to reduce emissions of greenhouse gases associated with our operations adversely affecting our profits or could adversely affect demand for the oil and natural gas we produce, depressing the prices we receive for oil and natural gas.

Some states have begun taking actions to control and/or reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or state or regional greenhouse gas cap-and-trade programs. Although most of the state-level initiatives have to date focused on significant sources of greenhouse gas emissions, such as coal-fired electric plants, it is possible that less significant sources of emissions could become subject to greenhouse gas emission limitations or emissions allowance purchase requirements in the future. Any one of these climate change regulatory and legislative initiatives could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Underground injection is the subsurface placement of fluid through a well, such as the reinjection of brine produced and separated from oil and natural gas production. In our industry, underground injection not only allows us to economically dispose of produced water, but if injected into an oil bearing zone, it can increase the oil production from such zone. The SDWA establishes a regulatory framework for underground injection, the primary objective of which is to ensure the mechanical integrity of the injection apparatus and to prevent migration of fluids from the injection zone into underground sources of drinking water. The disposal of hazardous waste by underground injection is subject to stricter requirements than the disposal of produced water. We currently own and operate five underground injection wells and expect to own other similar wells. Failure to obtain, or abide by, the requirements for the issuance of necessary permits could subject us to civil and/or criminal enforcement actions and penalties.

Our activities involve the use of hydraulic fracturing. For more information on our hydraulic fracturing operations, see "Business — Regulation — Hydraulic Fracturing Policies and Procedures." Recently, there has been increasing regulatory scrutiny of hydraulic fracturing, which is generally exempted from regulation as underground injection on the federal level pursuant to the SDWA. However, the U.S. Senate and House of Representatives have considered legislation to repeal this exemption. If enacted, these proposals would amend the definition of "underground injection" in the SDWA to encompass hydraulic fracturing activities. If enacted, such a provision could require hydraulic fracturing operations to meet permitting and financial assurance requirements, adhere to certain construction specifications, fulfill monitoring, reporting and recordkeeping obligations, and meet plugging and abandonment requirements. These legislative proposals have also contained language to require the reporting and public disclosure of chemicals used in the fracturing process. If the exemption for hydraulic fracturing is removed from the SDWA, or if other legislation is enacted at the federal, state or local level, any restrictions on the use of hydraulic fracturing contained in any such legislation could have a significant impact on our financial condition, results of operations and cash flows.

In addition, at the federal level and in some states, there has been a push to place additional regulatory burdens upon hydraulic fracturing activities and in some areas to severely restrict or prohibit those activities. Certain bills have been introduced in the Senate and the House of Representatives that, if adopted, could increase the possibility of litigation and establish an additional level of regulation at the federal level that could lead to operational delays or increased operating costs and could, and in all likelihood would, result in additional regulatory burdens, making it more difficult to perform hydraulic fracturing operations and increasing our costs of compliance. At the state level, Wyoming and Texas, for example, have enacted requirements for the disclosure of the composition of the fluids used in hydraulic fracturing. On June 17, 2011, Texas signed into law a mandate for public disclosure of the chemicals that operators use during hydraulic fracturing in Texas. The law went into effect in 2011 and implementing regulations have been adopted. In addition, at least a few local governments in Texas have imposed temporary moratoria on drilling permits within city limits so that local ordinances may be reviewed to assess their adequacy to address hydraulic fracturing activities. Additional burdens upon hydraulic fracturing, such as reporting requirements or permitting requirements for the hydraulic fracturing activity, will result in additional expense and delay in our operations.

The EPA has recently been taking action to assert federal regulatory authority over hydraulic fracturing using diesel under the SDWA's Underground Injection Control Program. The EPA is currently conducting a study on the effects of hydraulic fracturing on drinking water resources. Interim results of the study are expected in 2012, with final results expected in 2014. In addition, in December 2011, the EPA published an unrelated draft report concluding that hydraulic fracturing caused groundwater pollution in a natural gas field in Wyoming. This study remains subject to review and public comment but such studies could result in additional regulatory scrutiny that could make it difficult to perform hydraulic fracturing and increase our costs of compliance and doing business.

Oil and natural gas exploration and production, operations and other activities have been conducted at some of our properties by previous owners and operators. Materials from these operations remain on some of the properties, and, in some instances, require remediation. In addition, we occasionally must agree to indemnify sellers of producing properties from whom we acquire reserves against some of the liability for environmental claims associated with these properties. While we do not believe that costs we incur for compliance with environmental regulations and remediating previously or currently owned or operated properties will be material, we cannot provide any assurances that these costs will not result in material expenditures that adversely affect our profitability.

Additionally, in the course of our routine oil and natural gas operations, surface spills and leaks, including casing leaks, of oil or other materials will occur, and we will incur costs for waste handling and environmental compliance. It is also possible that our oil and natural gas operations may require us to manage NORM. NORM is present in varying concentrations in sub-surface formations, including hydrocarbon reservoirs, and may become concentrated in scale, film and sludge in equipment that comes in contact with crude oil and natural gas production and processing streams. Some states, including Texas, have enacted regulations governing the handling, treatment, storage and disposal of NORM. Moreover, we will be able to control directly the operations of only those wells for which we act as the operator. Despite our lack of control over wells owned by us but operated by others, the failure of the operator to comply with the applicable environmental regulations may, in certain circumstances, be attributable to us.

We are subject to the requirements of OSHA and comparable state statutes. The OSHA Hazard Communication Standard, the "community right-to-know" regulations under Title III of the federal Superfund Amendments and Reauthorization Act and similar state statutes require us to organize information about hazardous materials used, released or produced in our operations. Certain of this information must be provided to employees, state and local governmental authorities and local citizens. We are also subject to the requirements and reporting set forth in OSHA workplace standards.

We have not in the past been, and do not anticipate in the near future to be, required to expend amounts that are material in relation to our total capital expenditures as a result of environmental laws and regulations, but since these laws and regulations are periodically amended, we are unable to predict the ultimate cost of compliance. We cannot assure you that more stringent laws and regulations protecting the environment will not be adopted or that we will not otherwise incur material expenses in connection with environmental laws and regulations in the future. See "Risk Factors — We Are Subject to Government Regulation and Liability, including Complex Environmental Laws, Which Could Require Significant Expenditures."

The clear trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, and thus, any changes in environmental laws and regulations or re-interpretation of enforcement policies that result in more stringent and costly waste handling, storage, transport, disposal or remediation requirements could have a material adverse effect on our operations and financial position. We may be unable to pass on such increased compliance costs to our customers. Moreover, accidental releases or spills may occur in the course of our operations, and we cannot assure you that we will not incur significant costs and liabilities as a result of such releases or spills, including any third party claims for damage to property, natural resources or persons.

We maintain insurance against some, but not all, potential risks and losses associated with our industry and operations. We do not currently carry business interruption insurance. For some risks, we may not obtain insurance if we believe the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. If a significant accident or other event occurs and is not fully covered by insurance, it could materially adversely affect our financial condition, results of operations and cash flows.

Office Lease

Our corporate headquarters are located in 28,743 square feet of office space in One Lincoln Centre, 5400 LBJ Freeway, Suite 1500, Dallas, Texas. In April 2011, we entered into a third amended and restated office lease agreement pursuant to which our office space was increased from 20,849 to 28,743 square feet and the term of our lease was extended from July 1, 2011 to June 30, 2022. Beginning July 1, 2011, through

June 30, 2012, we are not required to pay a monthly base rent. From July 1, 2012 through June 30, 2015, our monthly base rent is $47,905. From July 1, 2015 through June 30, 2017, our monthly base rent is $50,300. From July 1, 2017 through June 30, 2019, our monthly base rent is $52,696. From July 1, 2019 through June 30, 2020, our monthly base rent is $55,091. From July 1, 2020 through the expiration date of the lease, our monthly base rent is $57,726. In addition, the lease contains a renewal option in our favor for an additional 60-month period at the then existing market rate as determined in accordance with the lease.

Employees

At December 31, 2011, we had 41 full-time employees. We believe that our relationships with our employees are satisfactory. No employee is covered by a collective bargaining agreement. From time to time, we use the services of independent consultants and contractors to perform various professional services, particularly in the areas of geology and geophysics, construction, design, well site surveillance and supervision, permitting and environmental assessment and legal and income tax preparation and accounting services. Independent contractors, at our request, drill all of our wells and usually perform field and on-site production operation services for us, including pumping, maintenance, dispatching, inspection and testing. If significant opportunities for company growth arise and require additional management and professional expertise, we will seek to employ qualified individuals to fill positions where that expertise is necessary to develop those opportunities.

Available Information

Our Internet website address is *www.matadorresources.com.* We expect to make available, free of charge, through our website, our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports, as soon as reasonably practicable after providing such reports to the SEC. Also, the charters of our Audit Committee and Nominating, Compensation and Planning Committee, and our Code of Ethics and Business Conduct for Officers, Directors and Employees, are available through our website and in print to any shareholder who provides a written request to the Corporate Secretary at One Lincoln Centre, 5400 LBJ Freeway, Suite 1500, Dallas, Texas 75240. The contents of our website are not intended to be incorporated by reference into this report or any other report or document we file and any reference to our website is intended to be an inactive textual reference only.

Item 1A. Risk Factors.

Risks Related to the Oil and Natural Gas Industry and Our Business

Our Success Is Dependent on the Prices of Oil and Natural Gas. Low Oil or Natural Gas Prices and the Substantial Volatility in These Prices May Adversely Affect Our Financial Condition and Our Ability to Meet Our Capital Expenditure Requirements and Financial Obligations.

The prices we receive for our oil and natural gas heavily influence our revenue, profitability, cash flow available for capital expenditures, access to capital and future rate of growth. Oil and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil and natural gas have been volatile. These markets will likely continue to be volatile in the future. The prices we receive for our production, and the levels of our production, depend on numerous factors. These factors include the following:

- the domestic and foreign supply of oil and natural gas;
- the domestic and foreign demand for oil and natural gas;
- the prices and availability of competitors' supplies of oil and natural gas;
- the actions of the Organization of Petroleum Exporting Countries, or OPEC, and state-controlled oil companies relating to oil price and production controls;
- the price and quantity of foreign imports;
- the impact of U.S. dollar exchange rates on oil and natural gas prices;
- domestic and foreign governmental regulations and taxes;
- speculative trading of oil and natural gas futures contracts;
- the availability, proximity and capacity of gathering and transportation systems for natural gas;
- the availability of refining capacity;
- the prices and availability of alternative fuel sources;
- weather conditions and natural disasters;
- political conditions in or affecting oil and natural gas producing regions, including the Middle East and South America;
- the continued threat of terrorism and the impact of military action and civil unrest;
- public pressure on, and legislative and regulatory interest within, federal, state and local governments to stop, significantly limit or regulate hydraulic fracturing activities;
- the level of global oil and natural gas inventories and exploration and production activity;
- the impact of energy conservation efforts;
- technological advances affecting energy consumption; and
- overall worldwide economic conditions.

Approximately 98% of our production during the year ended December 31, 2010, 94% of our production during the year ended December 31, 2011 and 88% of our proved reserves at December 31, 2011 are attributable to natural gas. In addition, three of our largest prospects, our Haynesville shale, Cotton Valley properties and our Meade Peak shale prospect, currently produce or are expected to produce predominantly natural gas. As a result, they are sensitive to fluctuations in natural gas prices.

One of our current business strategies is to focus on increasing our oil and liquids production. Specifically, our near-term drilling opportunities in the Eagle Ford shale play focus on oil and liquids. We currently intend to allocate approximately 84% of our 2012 capital expenditure budget to the exploration of the Eagle Ford shale. We believe that approximately 85% of our Eagle Ford acreage is prospective predominantly for oil and liquids production, and we have identified 193 gross locations for potential future drilling in our Eagle Ford acreage. Therefore, our Eagle Ford shale play is highly susceptible to changes in oil prices.

Declines in oil or natural gas prices not only reduce our revenue, but could also reduce the amount of oil and natural gas that we can produce economically. Should natural gas or oil prices decrease to economically unattractive levels and remain there for an extended period of time, we may elect in the future to delay some of our exploration and development plans for our prospects, or to cease exploration or development activities on certain prospects due to the anticipated unfavorable economics from such activities, each of which would have a material adverse effect on our business, financial condition, results of operations and reserves.

In recent months, natural gas prices have declined to their lowest levels in many years, and at March 30, 2012, the NYMEX Henry Hub natural gas futures contract for the earliest delivery date closed at \$2.13 per MMBtu. We would not expect to drill any operated natural gas wells, except for natural gas wells in specific exploration prospects like the Meade Peak shale, until natural gas prices improved substantially from these levels or unless the costs to drill and complete these wells were also to decline substantially from their recent levels.

Drilling for and Producing Oil and Natural Gas Are Highly Speculative and Involve a High Degree of Risk, with Many Uncertainties That Could Adversely Affect Our Business.

Exploring for and developing hydrocarbon reserves involves a high degree of operational and financial risk, which precludes us from definitively predicting the costs involved and time required to reach certain objectives. Our drilling locations are in various stages of evaluation, ranging from a location that is ready to drill to a location that will require substantial additional interpretation before it can be drilled. The budgeted costs of planning, drilling, completing and operating wells are often exceeded and such costs can increase significantly due to various complications that may arise during the drilling and operating processes. Before a well is spud, we may incur significant geological and geophysical (seismic) costs, which are incurred whether a well eventually produces commercial quantities of hydrocarbons, or is drilled at all. Exploration wells bear a much greater risk of loss than development wells. The analogies we draw from available data from other wells, more fully explored locations or producing fields may not be applicable to our drilling locations. If our actual drilling and development costs are significantly more than our estimated costs, we may not be able to continue our operations as proposed and could be forced to modify our drilling plans accordingly.

If we decide to drill a certain location, there is a risk that no commercially productive oil or natural gas reservoirs will be found or produced. We may drill or participate in new wells that are not productive. We may drill wells that are productive, but that do not produce sufficient net revenues to return a profit after drilling, operating and other costs. There is no way to predict in advance of drilling and testing whether any particular location will yield oil or natural gas in sufficient quantities to recover exploration, drilling or completion costs or to be economically viable. Even if sufficient amounts of oil or natural gas exist, we may damage the potentially productive hydrocarbon-bearing formation or experience mechanical difficulties while drilling or completing the well, resulting in a reduction in production and reserves from the well or abandonment of the well. Whether a well is ultimately productive and profitable depends on a number of additional factors, including the following:

- general economic and industry conditions, including the prices received for oil and natural gas;
- shortages of, or delays in, obtaining equipment, including hydraulic fracturing equipment, and qualified personnel;
- potential drainage by operators on adjacent properties;
- loss of or damage to oilfield development and service tools;
- problems with title to the underlying properties;
- increases in severance taxes;
- adverse weather conditions that delay drilling activities or cause producing wells to be shut down;
- domestic and foreign governmental regulations; and
- proximity to and capacity of transportation facilities.

If we do not drill productive and profitable wells in the future, our business, financial condition, results of operations, cash flows and reserves could be materially and adversely affected.

We May Have Accidents, Equipment Failures or Mechanical Problems While Drilling or Completing Wells or in Production Activities, Which Could Adversely Affect Our Business.

While we are drilling and completing wells or involved in production activities, we may have accidents or experience equipment failures or mechanical problems in a well that cause us to be unable to drill and complete the well or to continue to produce the well according to our plans. We may also damage a potentially hydrocarbon-bearing formation during drilling and completion operations. Such incidents may result in a reduction of our production and reserves from the well or in abandonment of the well.

Because Our Reserves and Production Are Concentrated in a Small Number of Properties, Problems in Production and Markets Relating to Any Property Could Have a Material Impact on Our Business.

Almost all of our current oil and natural gas production and our proved reserves are attributable to properties in northwest Louisiana and east Texas, and we expect that most of our operations in the near future will be primarily in south Texas. As a result, we may be disproportionately exposed to the impact of delays or interruptions of production from these wells caused by transportation capacity constraints or interruptions, curtailment of production, availability of equipment, facilities, personnel or services, significant governmental regulation, natural disasters, adverse weather conditions or plant closures for scheduled maintenance. In particular, our operations in south Texas may be adversely impacted by a lack of pipeline infrastructure and natural gas processing facilities in light of the oil and natural gas industry's increased focus on the exploration and development of the Eagle Ford shale. Our operations in south Texas may also be adversely affected by hurricanes and tropical storms resulting in delays in exploration and drilling, damage to facilities and equipment and the inability to receive equipment or to access personnel and products at affected job sites in a timely manner. Due to the concentrated nature of our portfolio of properties, a number of our properties could experience any of the same conditions at the same time, resulting in a relatively greater impact on our results of operations than they might have on other companies that have a more diversified portfolio of properties. Such delays or interruptions could have a material adverse effect on our financial condition, results of operations and cash flows.

Unless We Replace Our Oil and Natural Gas Reserves, Our Reserves and Production Will Decline, Which Would Adversely Affect Our Business, Financial Condition, Results of Operations and Cash Flows.

The rate of production from our oil and natural gas properties declines as our reserves are depleted. Our future oil and natural gas reserves and production and, therefore, our income and cash flow, are highly dependent on our success in: (i) efficiently developing and exploiting our current reserves on properties owned by us or by other persons or entities and (ii) economically finding or acquiring additional oil and natural gas producing properties. We are currently focusing primarily on increasing our production and reserves from the Eagle Ford shale play, an area in which industry activity has increased rapidly. As a result of this increased activity, we may have difficulty expanding our current production or acquiring new properties in this area and may experience such difficulty in other areas in the future. During periods of low oil and/or natural gas prices, it will become more difficult to raise the capital necessary to finance expansion activities. If we are unable to replace our current and future production, our reserves will decrease, and our business, financial condition, results of operations and cash flows would be adversely affected.

Our Oil and Natural Gas Reserves Are Estimated and May Not Reflect the Actual Volumes of Oil and Natural Gas We Will Receive, and Significant Inaccuracies in These Reserves Estimates or Underlying Assumptions Will Materially Affect the Quantities and Present Value of Our Reserves.

The process of estimating accumulations of oil and natural gas is complex and is not exact, due to numerous inherent uncertainties. The process relies on interpretations of available geological, geophysical, engineering and production data. The extent, quality and reliability of this technical data can vary. The process also requires certain economic assumptions related to, among other things, oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The accuracy of a reserves estimate is a function of:

- the quality and quantity of available data;
- the interpretation of that data;
- the judgment of the persons preparing the estimate; and
- the accuracy of the assumptions.

The accuracy of any estimates of proved reserves generally increases with the length of the production history. Due to the limited production history of many of our properties, the estimates of future production associated with these properties may be subject to greater variance to actual production than would be the case with properties having a longer production history. As our wells produce over time and more data is available, the estimated proved reserves will be redetermined on at least an annual basis and may be adjusted to reflect new information based upon our actual production history, results of exploration and development, prevailing oil and natural gas prices and other factors.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas most likely will vary from our estimates. It is possible that future production declines in our wells may be greater than we have estimated. Any significant variance to our estimates could materially affect the quantities and present value of our reserves.

The Calculated Present Value of Future Net Revenues from Our Proven Reserves Will Not Necessarily Be the Same as the Current Market Value of Our Estimated Oil and Natural Gas Reserves.

It should not be assumed that the present value of future net cash flows included in this report is the current market value of our estimated proved oil and natural gas reserves. We generally base the estimated discounted future net cash flows from proved reserves on current costs held constant over time without escalation and on commodity prices using an unweighted arithmetic average of first-day-of-the-month index prices, appropriately adjusted, for the 12-month period immediately preceding the date of the estimate. Actual future prices and costs may be materially higher or lower than the prices and costs used for these estimates and will be affected by factors such as:

- actual prices we receive for oil and natural gas;
- actual cost and timing of development and production expenditures;
- the amount and timing of actual production; and
- changes in governmental regulations or taxation.

In addition, the 10% discount factor that is required to be used to calculate discounted future net revenues for reporting purposes under Generally Accepted Accounting Principles, or GAAP, is not necessarily the most appropriate discount factor based on the cost of capital in effect from time to time and risks associated with our business and the oil and natural gas industry in general.

Approximately 67% of Our Total Proved Reserves at December 31, 2011 Consisted of Undeveloped and Developed Non-Producing Reserves, and Those Reserves May Not Ultimately Be Developed or Produced.

At December 31, 2011, approximately 66% of our total proved reserves were undeveloped and approximately 1% were developed non-producing. Our undeveloped and/or developed non-producing reserves may never be developed or produced or such reserves may not be developed or produced within the time periods we have projected or at the costs we have budgeted. Delays in the development of our reserves or increases in costs to drill and develop such reserves would reduce the present value of our estimated proved undeveloped reserves and future net revenues estimated for such reserves, resulting in some projects becoming uneconomical. In addition, delays in the development of reserves or declines in the oil and/or natural gas prices used to estimate proved reserves in the future could cause us to have to reclassify our proved reserves as unproved reserves, which would materially affect our business, financial condition, results of operations and ability to raise capital.

Our Exploration, Development and Exploitation Projects Require Substantial Capital Expenditures That May Exceed Our Cash Flows from Operations and Potential Borrowings, and We May Be Unable to Obtain Needed Capital on Satisfactory Terms, Which Could Adversely Affect Our Future Growth.

Our exploration and development activities are capital intensive. We make and expect to continue to make substantial capital expenditures in our business for the development, exploitation, production and acquisition of oil and natural gas reserves. Our cash and cash equivalents, operating cash flows and future potential borrowings under our credit agreement or otherwise may not be adequate to fund our future acquisitions or future capital expenditure requirements. The rate of our future growth may be dependent, at least in part, on our ability to access capital at rates and on terms we determine to be acceptable.

We may sell additional securities to raise capital. If we succeed in selling additional securities to raise funds, at such time the ownership of our existing shareholders would likely be diluted, and new investors may demand rights, preferences or privileges senior to those of existing shareholders. If we raise additional capital through the issuance of new debt securities or additional indebtedness, we may become subject to additional covenants that restrict our business activities.

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

- our estimated proved oil and natural gas reserves;
- the amount of oil and natural gas we produce from existing wells;
- the prices at which we sell our production;

- the costs of developing and producing our oil and natural gas reserves;
- our ability to acquire, locate and produce new reserves;
- the ability and willingness of banks to lend to us; and
- our ability to access the equity and debt capital markets.

In addition, future events, such as terrorist attacks, wars or combat peace-keeping missions, financial market disruptions, general economic recessions, oil and natural gas industry recessions, large company bankruptcies, accounting scandals, overstated reserves estimates by major public oil companies and disruptions in the financial and capital markets have caused financial institutions, credit rating agencies and the public to more closely review the financial statements, capital structures and earnings of public companies, including energy companies. Such events have constrained the capital available to the energy industry in the past, and such events or similar events could adversely affect our access to funding for our operations in the future.

If our revenues decrease as a result of lower oil and gas prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels, further develop and exploit our current properties or invest in additional exploration opportunities. Alternatively, a significant improvement in oil and gas prices could result in an increase in our capital expenditures and we may be required to alter or increase our capitalization substantially through the issuance of debt or equity securities, the sale of production payments, the sale of non-strategic assets, the borrowing of funds or otherwise to meet any increase in capital needs. If we are unable to raise additional capital from available sources at acceptable terms, our business, financial condition and future results of operations could be adversely affected.

Our Operations Are Subject to Operational Hazards and Unforeseen Interruptions for Which We May Not Be Adequately Insured.

There are numerous operational hazards inherent in oil and natural gas exploration, development, production and gathering, including:

- unusual or unexpected geologic formations;
- natural disasters;
- adverse weather conditions;
- unanticipated pressures;
- loss of drilling fluid circulation;
- blowouts where oil or natural gas flows uncontrolled at a wellhead;
- cratering or collapse of the formation;
- pipe or cement leaks, failures or casing collapses;
- fires or explosions;
- releases of hazardous substances or other waste materials that cause environmental damage;
- pressures or irregularities in formations; and
- equipment failures or accidents.

In addition, there is an inherent risk of incurring significant environmental costs and liabilities in the performance of our operations, some of which may be material, due to our handling of petroleum hydrocarbons and wastes, our emissions to air and water, the underground injection or other disposal of our wastes, the use of hydraulic fracturing fluids and historical industry operations and waste disposal practices. Any of these or other similar occurrences could result in the disruption or impairment of our operations, substantial repair costs, personal injury or loss of human life, significant damage to property, environmental pollution and substantial revenue losses. The location of our wells, gathering systems, pipelines and other facilities near populated areas, including residential areas, commercial business centers and industrial sites, could significantly increase the level of damages resulting from these risks.

Insurance against all operational risks is not available to us. We are not fully insured against all risks, including development and completion risks that are generally not recoverable from third parties or insurance. In addition, pollution and environmental risks generally are not fully insurable. Additionally, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the perceived risks presented. Losses could, therefore, occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. Moreover, insurance may not be available in the future at commercially reasonable prices or on commercially reasonable terms. Changes in the insurance markets due to various factors may make it more difficult for us to obtain certain types of coverage in the future. As a result, we may not be able to obtain the levels or types of insurance we would otherwise have obtained prior to these market changes, and the insurance coverage we do obtain may not cover certain hazards or all potential losses that are currently covered, and may be subject to large deductibles. Losses and liabilities from uninsured and underinsured events and delays in the payment of insurance proceeds could have a material adverse effect on our business, financial condition, results of operations and cash flows.

The 2-D and 3-D Seismic Data and Other Advanced Technologies We Use Cannot Eliminate Exploration Risk, Which Could Limit Our Ability to Replace and Grow Our Reserves and Materially and Adversely Affect Our Future Cash Flows and Results of Operations.

We intend to employ visualization and 2-D and 3-D seismic images to assist us in exploration and development activities where applicable. These techniques only assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not allow the interpreter to know conclusively if hydrocarbons are present or economically producible. We could incur losses by drilling unproductive wells based on these technologies. Poor results from our exploration activities could limit our ability to replace and grow reserves and materially and adversely affect our future cash flows and results of operations.

We Currently Own Only a Limited Amount of Seismic and Other Geological Data and May Have Difficulty Obtaining Additional Data at a Reasonable Cost, Which Could Adversely Affect Our Future Cash Flows and Results of Operations.

We currently own only a limited amount of seismic and other geological data to assist us in exploration and development activities. We intend to obtain access to additional data in our areas of interest through licensing arrangements with companies that own or have access to that data or by paying to obtain that data directly. Seismic and geological data can be expensive to license or obtain. We may not be able to license or obtain such data at an acceptable cost.

The Unavailability or High Cost of Drilling Rigs, Completion Equipment and Services, Supplies and Personnel, Including Hydraulic Fracturing Equipment and Personnel, Could Adversely Affect Our Ability to Establish and Execute Exploration and Development Plans within Budget and on a Timely Basis, Which Could Have a Material Adverse Effect on Our Financial Condition, Results of Operations and Cash Flows.

Shortages or the high cost of drilling rigs, completion equipment and services, supplies or personnel could delay or adversely affect our operations. When drilling activity in the United States increases, associated costs typically also increase, including those costs related to drilling rigs, equipment, supplies and personnel and the services and products of other vendors to the industry. These costs may increase, and necessary equipment and services may become unavailable to us at economical prices. Should this increase in costs occur, we may delay drilling activities, which may limit our ability to establish and replace reserves, or we may incur these higher costs, which may negatively affect our financial condition, results of operations and cash flows.

In addition, the demand for hydraulic fracturing services currently exceeds the availability of fracturing equipment and crews across the industry and in our operating areas in particular. The accelerated wear and tear of hydraulic fracturing equipment due to its deployment in unconventional oil and natural gas fields characterized by longer lateral lengths and larger numbers of fracturing stages has further amplified this equipment and crew shortage. If demand for fracturing services continues to increase or the supply of fracturing equipment and crews decreases, then higher costs could result and could adversely affect our business and results of operations.

Our Identified Drilling Locations Are Scheduled Out Over Several Years, Making Them Susceptible to Uncertainties That Could Materially Alter the Occurrence or Timing of Their Drilling.

Our management team has identified and scheduled drilling locations in our operating areas over a multi-year period. Our ability to drill and develop these locations depends on a number of factors, including the availability of equipment and capital, approval by regulators, seasonal conditions, oil and natural gas prices, assessment of risks, costs and drilling results. The final determination on whether to drill any of these locations will be dependent upon the factors described elsewhere in this report as well as, to some degree, the results of our drilling activities with respect to our established drilling locations. Because of these uncertainties, we do not know if the drilling locations we have identified will be drilled within our expected timeframe or at all or if we will be able to economically produce hydrocarbons from these or any other potential drilling locations. Our actual drilling activities may be materially different from our current expectations, which could adversely affect our financial condition, results of operations and cash flows.

We Have Limited Control Over Activities on Properties We Do Not Operate.

We are not the operator on some of our properties, particularly in the Haynesville shale. As a result of our sale of certain assets to a subsidiary of Chesapeake Energy Corporation in 2008, we do not operate one of our most significant natural gas assets in the Haynesville shale. We have also acquired other non-operated acreage positions in northwest Louisiana. Because we are not the operator for these properties, our ability to exercise influence over the operations of these properties or their associated costs is limited. Our dependence on the operators and other working interest owners of these projects and our limited ability to influence operations and associated costs or control the risks could materially and adversely affect the realization of our targeted returns on capital in drilling or acquisition activities. The success and timing of our drilling and development activities on properties operated by others therefore depends upon a number of factors, including:

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

In areas where we do not have the right to propose the drilling of wells, we may have limited influence on when, how and at what pace our properties in those areas are developed. Further, the operators of those properties may experience financial problems in the future or may sell their rights to another operator not of our choosing, both of which could limit our ability to develop and monetize the underlying natural gas reserves. In addition, the operators of these properties may elect to curtail the oil or natural gas production or to shut in the wells on these properties during periods of low oil or natural gas prices, and we may receive less than anticipated or no production and associated revenues from these properties until the operator elects to return them to production.

A Component of Our Growth May Come Through Acquisitions, and Our Failure to Identify or Complete Future Acquisitions Successfully Could Reduce Our Earnings and Hamper Our Growth.

We may be unable to identify properties for acquisition or to make acquisitions on terms that we consider economically acceptable. There is intense competition for acquisition opportunities in our industry. Competition for acquisitions may increase the cost of, or cause us to refrain from, completing acquisitions. The completion and pursuit of acquisitions may be dependent upon, among other things, our ability to obtain debt and equity financing and, in some cases, regulatory approvals. Our ability to grow through acquisitions will require us to continue to invest in operations, financial and management information systems and to attract, retain, motivate and effectively manage our employees. The inability to manage the integration of acquisitions effectively could reduce our focus on subsequent acquisitions and current operations, and could negatively impact our results of operations and growth potential. Our financial position, results of operations and cash flows may fluctuate significantly from period to period as a result of the completion of significant acquisitions during particular periods. If we are not successful in identifying or acquiring any material property interests, our earnings could be reduced and our growth could be restricted.

We may engage in bidding and negotiating to complete successful acquisitions. We may be required to alter or increase substantially our capitalization to finance these acquisitions through the use of cash on hand, the issuance of debt or equity securities, the sale of production payments, the sale of non-strategic assets, the borrowing of funds or otherwise. Our credit agreement includes covenants limiting our ability to incur additional debt. If we were to proceed with one or more acquisitions involving the issuance of our common stock, our shareholders would suffer dilution of their interests. Furthermore, our decision to acquire properties that are substantially different in operating or geologic characteristics or geographic locations from areas with which our staff is familiar may impact our productivity in such areas.

We May Purchase Oil and Natural Gas Properties with Liabilities or Risks That We Did Not Know About or That We Did Not Assess Correctly, and, as a Result, We Could Be Subject to Liabilities That Could Adversely Affect Our Results of Operations.

Before acquiring oil and natural gas properties, we estimate the reserves, future oil and natural gas prices, operating costs, potential environmental liabilities and other factors relating to the properties. However, our review involves many assumptions and estimates, and their accuracy is inherently uncertain. As a result, we may not discover all existing or potential problems associated with the properties we buy. We may not become sufficiently familiar with the properties to assess fully their deficiencies and capabilities. We do not generally perform inspections on every well or property, and we may not be able to observe mechanical and environmental problems even when we conduct an inspection. The seller may not be willing or financially able to give us contractual protection against any identified problems, and we may decide to assume environmental and other liabilities in connection with properties we acquire. If we acquire properties with risks or liabilities we did not know about or that we did not assess correctly, our financial condition, results of operations and cash flows could be adversely affected as we settle claims and incur cleanup costs related to these liabilities.

Strategic Relationships Upon Which We May Rely Are Subject to Change, Which May Diminish Our Ability to Conduct Our Operations.

Our ability to explore, develop and produce oil and natural gas resources successfully and acquire oil and natural gas interests and acreage depends on our developing and maintaining close working relationships with industry participants and on our ability to select and evaluate suitable acquisition opportunities in a highly competitive environment. These realities are subject to change and may impair our ability to grow.

To develop our business, we will endeavor to use the business relationships of our management, board and special board advisors to enter into strategic relationships, which may take the form of contractual arrangements with other oil and natural gas companies, including those that supply equipment and other resources that we expect to use in our business. We may not be able to establish these strategic relationships, or if established, we may not be able to maintain them. In addition, the dynamics of our relationships with strategic partners may require us to incur expenses or undertake activities we would not otherwise be inclined to incur in order to fulfill our obligations to these partners or maintain our relationships. If our strategic relationships are not established or maintained, our business prospects may be limited, which could diminish our ability to conduct our operations.

The Marketability of Our Production Is Dependent Upon Oil and Natural Gas Gathering and Transportation Facilities Owned and Operated by Third Parties, and the Unavailability of Satisfactory Oil and Natural Gas Transportation Arrangements Would Have a Material Adverse Effect on Our Revenue.

The unavailability of satisfactory oil and natural gas transportation arrangements may hinder our access to oil and natural gas markets or delay production from our wells. 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 and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends in substantial part on the availability and capacity of gathering systems, pipelines and processing facilities owned and operated by third parties. Our failure to obtain these services on acceptable terms could materially harm our business. We may be required to shut in wells for lack of a market or because of inadequacy or unavailability of pipeline or gathering system capacity. If that were to occur, we would be unable to realize revenue from those wells until production arrangements were made to deliver our production to market. Furthermore, if we were required to shut in wells we might also be obligated to pay shut-in royalties to certain mineral interest owners in order to maintain our leases.

The disruption of third party facilities due to maintenance and/or weather could negatively impact our ability to market and deliver our products. The third parties control when or if such facilities are restored and what prices will be charged. We generally do not purchase firm transportation on third party facilities, and, therefore, our production transportation can be interrupted by those having firm arrangements. Federal and state regulation of oil and natural gas production and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines and general economic conditions could adversely affect our ability to produce, gather and transport oil and natural gas.

Hedging Transactions, or the Lack Thereof, May Limit Our Potential Gains and Could Result in Financial Losses.

To manage our exposure to price risk, we, from time to time, enter into hedging arrangements, using primarily "costless collars," with respect to a portion of our future production. A costless collar provides us with downside price protection through the purchase of a put option which is financed through the sale of a call option. Because the call option proceeds are used to offset the cost of the put option, this arrangement is initially "costless" to us. The goal of these and other hedges is to lock in a range of prices so as to mitigate price volatility and increase the predictability of cash flows. These transactions limit our potential gains if oil or natural gas prices rise above the maximum price established by the call option and may offer protection if prices fall below the minimum price established by the put option only to the extent of the volumes then hedged.

In addition, hedging transactions may expose us to the risk of financial loss in certain other circumstances, including instances in which our production is less than expected or the counterparties to our put and call option contracts fail to perform under the contracts.

Disruptions in the financial markets could lead to sudden changes in a counterparty's liquidity, which could impair its ability to perform under the terms of the contracts. We are unable to predict sudden changes in a counterparty's creditworthiness or ability to perform under contracts with us. Even if we do accurately predict sudden changes, our ability to mitigate that risk may be limited depending upon market conditions.

Furthermore, there may be times when we have not hedged our production when, in retrospect, it would have been advisable to do so. Decisions as to whether and what production volumes to hedge are difficult and depend on market conditions and our forecast of future production and oil and gas prices, and we may not always employ the optimal hedging strategy. We may employ hedging strategies in the future that differ from those that we have used in the past, and neither the continued application of our current strategies nor our use of different hedging strategies may be successful.

An Increase in the Differential Between the NYMEX or Other Benchmark Prices of Oil and Natural Gas and the Wellhead Price We Receive for Our Production Could Adversely Affect Our Business, Financial Condition, Results of Operations and Cash Flows.

The prices that we receive for our oil and natural gas production sometimes reflect a discount to the relevant benchmark prices, such as NYMEX, that are used for calculating hedge positions. The difference between the benchmark price and the prices we receive is called a differential. Increases in the differential between the benchmark prices for oil and natural gas and the wellhead price we receive could adversely affect our business, financial condition, results of operations and cash flows. We do not have, and may not have in the future, any derivative contracts covering the amount of the basis differentials we experience in respect of our production. As such, we will be exposed to any increase in such differentials.

We Are Subject to Government Regulation and Liability, including Complex Environmental Laws, Which Could Require Significant Expenditures.

The exploration, development, production and sale of oil and natural gas in the United States are subject to many federal, state and local laws, rules and regulations, including complex environmental laws and regulations. Matters subject to regulation include discharge permits, drilling bonds, reports concerning operations, the spacing of wells, unitization and pooling of properties, taxation or environmental matters and health and safety criteria addressing worker protection. Under these laws and regulations, we may be required to make large expenditures that could materially adversely affect our financial condition, results of operations and cash flows. These expenditures could include payments for:

- personal injuries;
- property damage;
- containment and clean up of oil and other spills;
- the management and disposal of hazardous materials;

- remediation and clean-up costs; and
- other environmental damages.

We do not believe that full insurance coverage for all potential damages is available at a reasonable cost. Failure to comply with these laws and regulations also may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties, injunctive relief and/or the imposition of investigatory or other remedial obligations. Laws, rules and regulations protecting the environment have changed frequently and the changes often include increasingly stringent requirements. These laws, rules and regulations may impose liability on us for environmental damage and disposal of hazardous materials even if we were not negligent or at fault. We may also be found to be liable for the conduct of others or for acts that complied with applicable laws, rules or regulations at the time we performed those acts. These laws, rules and regulations are interpreted and enforced by numerous federal and state agencies. In addition, private parties, including the owners of properties upon which our wells are drilled or the owners of properties adjacent to or in close proximity to those properties, may also pursue legal actions against us based on alleged non-compliance with certain of these laws, rules and regulations.

We Are Subject to Federal, State and Local Taxes, and May Become Subject to New Taxes or Have Eliminated or Reduced Certain Federal Income Tax Deductions Currently Available with Respect to Oil and Natural Gas Exploration and Production Activities as a Result of Future Legislation, Which Could Adversely Affect Our Business, Financial Condition, Results of Operations and Cash Flows.

The federal, state and local governments in the areas in which we operate impose taxes on the oil and natural gas products we sell and, for many of our wells, sales and use taxes on significant portions of our drilling and operating costs. In the past, there has been a significant amount of discussion by legislators and presidential administrations concerning a variety of energy tax proposals. Many states have raised state taxes on energy sources, and additional increases may occur. Changes to tax laws that are applicable to us could adversely affect our business and our financial results.

Periodically, legislation is introduced to eliminate certain key U.S. federal income tax preferences currently available to oil and natural gas exploration and production companies. Such 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, (iii) the elimination of the deduction for certain United States production activities and (iv) the increase in the amortization period for geological and geophysical costs paid or incurred in connection with the exploration for, or development of, oil or natural gas within the United States. These changes were included in the White House budget proposals, released on February 26, 2009, February 1, 2010, February 14, 2011 and February 13, 2012, and may be raised again in the future. The passage of any legislation as a result of the budget proposals or any other similar change in U.S. federal income tax law could affect certain tax deductions that are currently available with respect to oil and natural gas exploration and production activities and could negatively impact our financial condition, results of operations and cash flows.

We May Be Required to Write Down the Carrying Value of Our Proved Properties Under Accounting Rules and these Write-Downs Could Adversely Affect Our Financial Condition.

There is a risk that we will be required to write down the carrying value of our oil and natural gas properties when oil or natural gas prices are low. In addition, non-cash write-downs may occur if we have:

- downward adjustments to our estimated proved reserves;

- increases in our estimates of development costs; or
- deterioration in our exploration results.

We periodically review the carrying value of our oil and natural gas properties under full-cost accounting rules. Under these rules, the net capitalized costs of oil and natural gas properties less related deferred income taxes may not exceed a cost center ceiling that is based on the present value, based on constant prices and costs projected forward from a single point in time, of estimated future after-tax net cash flows from proved reserves, discounted at 10%. If the net capitalized costs of our oil and natural gas properties less related deferred income taxes exceed the cost center ceiling, we must charge the amount of this excess to operations in the period in which the excess occurs. We may not reverse write-downs even if prices increase in subsequent periods. A write-down does not affect net cash flows from operating activities, but it does reduce the book value of our net tangible assets, retained earnings and shareholders' equity and could lower the value of our common stock.

We May Incur Losses or Costs as a Result of Title Deficiencies in the Properties in Which We Invest.

If an examination of the title history of a property that we have purchased reveals an oil and natural gas lease has been purchased in error from a person who is not the owner of the mineral interest desired, our interest would be worthless. In such an instance, the amount paid for such oil and natural gas lease as well as any royalties paid pursuant to the terms of the lease prior to the discovery of the title defect would be lost.

It is our practice, in acquiring oil and natural gas leases, or undivided interests in oil and natural gas leases, not to undergo the expense of retaining lawyers to examine the title to the mineral interest to be placed under lease or already placed under lease. Rather, we will rely upon the judgment of oil and natural gas lease brokers and/or landmen who perform the field work in examining records in the appropriate governmental office before attempting to acquire a lease on a specific mineral interest.

Prior to the drilling of an oil and natural gas well, however, it is the normal practice in the oil and natural gas industry for the person or company acting as the operator of the well to obtain a preliminary title review of the spacing unit within which the proposed oil and natural gas well is to be drilled to ensure there are no obvious deficiencies in title to the well. Frequently, as a result of such examinations, certain curative work must be done to correct deficiencies in the marketability of the title, and such curative work entails expense. Our failure to cure any title defects may adversely impact our ability in the future to increase production and reserves. In the future, we may suffer a monetary loss from title defects or title failure. Additionally, unproved and unevaluated acreage has greater risk of title defects than developed acreage. If there are any title defects or defects in assignment of leasehold rights in properties in which we hold an interest, we will suffer a financial loss which could adversely affect our financial condition, results of operations and cash flows.

The Derivatives Legislation Adopted by Congress Could Have an Adverse Impact on Our Ability to Hedge Risks Associated with Our Business.

On July 21, 2010, President Obama signed into law the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act, which is intended to modernize and protect the integrity of the U.S. financial system. The Dodd-Frank Act, among other things, sets forth the new framework for regulating certain derivative products including the commodity hedges of the type used by us, but many aspects of this law are subject to further rulemaking and will take effect over several years. As a result, it is difficult to anticipate the overall impact of the Dodd-Frank Act on our ability or willingness to continue entering into and maintaining such commodity hedges and the terms thereof. Based upon the limited assessments we are able to make with respect to the Dodd-Frank Act, there is the possibility that the Dodd-Frank Act could have a substantial and adverse impact on our ability to enter into and maintain these commodity hedges. In particular, the Dodd-Frank Act could result in the implementation of position limits and additional regulatory requirements on our derivative arrangements, which could include new margin, reporting and clearing requirements. In addition, this legislation could have a substantial impact on our counterparties and may increase the cost of our derivative arrangements in the future.

If these types of commodity hedges become unavailable or uneconomic, our commodity price risk could increase, which would increase the volatility of revenues and may decrease the amount of credit available to us. Any limitations or changes in our use of derivative arrangements could also materially affect our future ability to conduct acquisitions.

Federal and State Legislation and Regulatory Initiatives Relating to Hydraulic Fracturing Could Result in Increased Costs and Additional Operating Restrictions or Delays.

In past sessions, Congress has considered, but did not pass, legislation to amend the SDWA to remove the exemption from restrictions on underground injection of fluids near drinking water sources granted to most hydraulic fracturing operations and to require reporting and disclosure of chemicals used by oil and natural gas companies in the hydraulic fracturing process. Hydraulic fracturing involves the injection of water, sand or other propping agents and chemicals under pressure into rock formations to stimulate oil and natural gas production. We routinely use hydraulic fracturing to produce commercial quantities of oil, liquids and natural gas from shale formations such as the Eagle Ford and the Haynesville shales, where we focus our operations. Sponsors of bills before the Senate and House of Representatives have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. Such legislation, if adopted, could increase the possibility of litigation and establish an additional level of regulation at the federal level that could lead to operational delays or increased operating costs and could, and in all likelihood would, result in additional regulatory burdens, making it more difficult to perform hydraulic fracturing operations and increasing our costs of compliance. Moreover, the EPA is conducting a comprehensive research study on the potential adverse impacts that hydraulic fracturing may have on drinking water and groundwater. In addition, in December 2011, the EPA published an unrelated draft report concluding that hydraulic fracturing caused groundwater pollution of a natural gas field in Wyoming, although this study remains subject to review and public comments. Consequently, even if federal legislation is not adopted soon or at all, the performance of the hydraulic fracturing study by the EPA could spur further action at a later date towards federal legislation and regulation of hydraulic fracturing or similar production operations.

In addition, a number of states are considering or have implemented more stringent regulatory requirements applicable to fracturing, which could include a moratorium on drilling and effectively prohibit further production of natural gas through the use of hydraulic fracturing or similar operations. For example, Texas has adopted legislation that requires the disclosure of information regarding the substances used in the hydraulic fracturing process to the Railroad Commission of Texas and the public. This legislation and any implementing regulation could increase our costs of compliance and doing business.

The adoption of new laws or regulations imposing reporting obligations on, or otherwise limiting, the hydraulic fracturing process could make it more difficult to complete oil and natural gas wells in shale formations. In addition, if hydraulic fracturing becomes regulated at the federal level as a result of federal legislation or regulatory initiatives by the EPA, fracturing activities could become subject to additional permitting requirements, and also to attendant permitting delays and potential increases in cost, which could adversely affect our business and results of operations.

Legislation or Regulations Restricting Emissions of "Greenhouse Gases" Could Result in Increased Operating Costs and Reduced Demand for the Natural Gas, Natural Gas Liquids and Oil We Produce While the Physical Effects of Climate Change Could Disrupt Our Production and Cause Us to Incur Significant Costs in Preparing for or Responding to those Effects.

The EPA has published its final findings that emissions of carbon dioxide, methane and other "greenhouse gases" present an endangerment to public health and welfare because emissions of such gases are, according to the EPA, contributing to the warming of the earth's atmosphere and other climatic changes. These findings allow the EPA to adopt and implement regulations that would restrict emissions of greenhouse gases under existing provisions of the CAA. Accordingly, the EPA has adopted regulations that would require a reduction in emissions of greenhouse gases from motor vehicles and permitting and presumably requiring a reduction in greenhouse gas emissions from certain stationary sources. In addition, on October 30, 2009, the EPA published a final rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States beginning in 2011 for emissions occurring in 2010. On November 30, 2010, the EPA released a final rule that expands its rule on reporting of greenhouse gas emissions to include owners and operators of petroleum and natural gas systems. Monitoring of those newly covered emissions commenced on January 1, 2011, with the first annual reports due to the EPA in 2012. The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of greenhouse gases from, our equipment and operations could require us to incur costs to reduce emissions of greenhouse gases associated with our operations. There were attempts at comprehensive federal legislation establishing a cap and trade program, but that legislation did not pass. Further, various states have considered or adopted legislation that seeks to control or reduce emissions of greenhouse gases from a wide range of sources. Any such legislation could adversely affect demand for the natural gas, oil and liquids that we produce.

A Change in the Jurisdictional Characterization of Some of Our Assets by FERC or a Change in Policy by It May Result in Increased Regulation of Our Assets, Which May Cause Our Revenues to Decline and Operating Expenses to Increase.

Section 1(b) of the NGA exempts natural gas gathering facilities from regulation by FERC as a natural gas company under the NGA. We believe that the natural gas pipelines in our gathering systems meet the traditional tests FERC has used to establish a pipeline's status as a gatherer not subject to regulation as a natural gas company. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of ongoing litigation, so the classification and regulation of our gathering facilities are subject to change based on future determinations by FERC, the courts or Congress. A change in the jurisdictional characterization by FERC or Congress or a change in policy by either of them may result in increased regulation of our assets, which may cause our revenues to decline and operating expenses to increase.

Should We Fail to Comply with All Applicable FERC-Administered Statutes, Rules, Regulations and Orders, We Could Be Subject to Substantial Penalties and Fines.

Under the Energy Policy Act, FERC has civil penalty authority under the NGA to impose penalties for current violations of up to $1.0 million per day for each violation and disgorgement of profits associated with any violation. Our systems have not yet been regulated by FERC, as a natural gas company subject to the provisions of the NGA. FERC has adopted regulations that may subject certain of our otherwise non-FERC/NGA jurisdictional facilities to FERC annual reporting and daily scheduled flow and capacity posting requirements. Additional laws, rules and regulations pertaining to those and other matters may be considered or adopted by FERC or Congress from time to time. Failure to comply with those laws, rules and regulations in the future could subject us to civil penalty liability.

Competition in the Oil and Natural Gas Industry Is Intense Making It More Difficult for Us to Acquire Properties, Market Natural Gas and Secure Trained Personnel.

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 for acquiring properties, marketing oil and natural gas and securing trained personnel. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours. 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, other 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 in recent years due to competition and may increase substantially in the future. 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, which could have a material adverse effect on our business.

Our Competitors May Use Superior Technology and Data Resources that We May Be Unable to Afford or that Would Require a Costly Investment by Us in Order to Compete with Them More Effectively.

Our industry is subject to rapid and significant advancements in technology, including the introduction of new products and services using new technologies and databases. As our competitors use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement new technologies at a substantial cost. In addition, many of our competitors will have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we can. We cannot be certain that we will be able to implement technologies on a timely basis or at a cost that is acceptable to us. One or more of the technologies that we will use or that we may implement in the future may become obsolete, and we may be adversely affected.

Certain of Our Unproved and Unevaluated Acreage Is Subject to Leases that Will Expire Over the Next Several Years Unless Production Is Established on Units Containing the Acreage.

At December 31, 2011, we had leasehold interests in approximately 116,000 net acres across all of our areas of interest that are not currently held by production and are subject to leases with primary or renewed terms that expire prior to December 31, 2013. Unless we establish production in paying quantities on units containing these leases during their terms or we renew such leases, these leases will expire. If our leases expire, we will lose our right to develop the related properties. The cost to renew such leases may increase significantly, and we may not be able to renew such leases on commercially reasonable terms or at all. In addition, on certain portions of our acreage, third party leases may have been taken and could become immediately effective if our leases expire. As such, our actual drilling activities may materially differ from our current expectations, which could adversely affect our business, financial condition, results of operations and cash flows.

We May Have Difficulty Managing Growth in Our Business, Which Could Have a Material Adverse Effect on Our Business, Financial Condition, Results of Operations and Cash Flows and Our Ability to Execute Our Business Plan in a Timely Fashion.

Because of our small size, growth in accordance with our business plans, if achieved, will place a significant strain on our financial, technical, operational and management resources. As we expand our activities, including our planned increase in oil exploration, development and production, and increase the number of projects we are evaluating or in which we participate, there will be additional demands on our financial, technical and management resources. The failure to continue to upgrade our technical, administrative, operating and financial control systems or the occurrence of unexpected expansion difficulties, including the inability to recruit and retain experienced managers, geoscientists, petroleum engineers and landmen could have a material adverse effect on our business, financial condition, results of operations and cash flows and our ability to execute our business plan in a timely fashion.

Financial Difficulties Encountered by Our Oil and Natural Gas Purchasers, Third Party Operators or Other Third Parties Could Decrease Our Cash Flow from Operations and Adversely Affect the Exploration and Development of Our Prospects and Assets.

We derive essentially all of our revenues from the sale of our oil and natural gas to unaffiliated third party purchasers, independent marketing companies and mid-stream companies. Any delays in payments from our purchasers caused by financial problems encountered by them will have an immediate negative effect on our results of operations and cash flows.

Liquidity and cash flow problems encountered by our working interest co-owners or the third party operators of our non-operated properties may prevent or delay the drilling of a well or the development of a project. Our working interest co-owners may be unwilling or unable to pay their share of the costs of projects as they become due. In the case of a farmout party, we would have to find a new farmout party or obtain alternative funding in order to complete the exploration and development of the prospects subject to a farmout agreement. In the case of a working interest owner, we could be required to pay the working interest owner's share of the project costs. We cannot assure you that we would be able to obtain the capital necessary to fund either of these contingencies or that we would be able to find a new farmout party.

We May Incur Indebtedness Which Could Reduce Our Financial Flexibility, Increase Interest Expense and Adversely Impact Our Operations and Our Unit Costs.

At March 30, 2012, we had available borrowings of approximately $108.7 million under our credit agreement (after giving effect to outstanding letters of credit). Our borrowing base is determined semi-annually by our lenders based primarily on the estimated value of our existing and future acquired oil and gas reserves. Our credit agreement is secured by substantially all of our interests in our oil and gas properties and other assets and contains covenants restricting our ability to incur additional indebtedness, which may limit our ability to obtain additional financing. In addition, the borrowing base under our credit agreement is subject to periodic redeterminations, and we could be forced to repay a portion of our borrowings due to redeterminations of our borrowing base. If we are forced to do so, we may not have sufficient funds to make such repayments.

Borrowings under our credit agreement at March 30, 2012 bear interest at a variable rate of 1.75% plus a Eurodollar-based rate per annum, which equated to approximately 2.0% per annum. In the future, we may incur significant amounts of additional indebtedness, including under our credit agreement, in order to make acquisitions or to develop our properties. Interest rates on such future indebtedness may be higher than current levels, causing our financing costs to increase accordingly.

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

- a significant portion of our cash flows could be used to service our indebtedness;
- a high level of debt would increase our vulnerability to general adverse economic and industry conditions;
- any covenants contained in the agreements governing our outstanding indebtedness could limit our ability to borrow additional funds, dispose of assets, pay dividends and make certain investments;
- a high level of debt may place us at a competitive disadvantage compared to our competitors that are less leveraged and, therefore, may be able to take advantage of opportunities that our indebtedness may prevent us from pursuing;
- our debt covenants may also affect our flexibility in planning for, and reacting to, changes in the economy and in our industry; and
- a high level of debt may impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions and general corporate or other purposes.

A high level of indebtedness increases the risk that we may default on our debt obligations. Our ability to meet our debt obligations and to reduce our level of indebtedness depends on our future performance. General economic conditions, oil and natural gas prices and financial, business and other factors affect our operations and our future performance. We may not be able to generate sufficient cash flows to pay the principal or interest on our debt, and future working capital, borrowings or equity financing may not be available to pay or refinance such debt. Factors that will affect our ability to raise cash through an offering of our capital stock or a refinancing of our debt include financial market conditions, the value of our assets and our performance at the time we need capital. If we do not have sufficient funds and are otherwise unable to negotiate renewals of our borrowings or arrange new financing, we may have to sell significant assets or have a portion of our assets foreclosed upon which could have a material adverse effect on our business and financial results.

Our Success Depends, to a Large Extent, on Our Ability to Retain Our Key Personnel, Including Our Chairman of the Board, Chief Executive Officer and President, the Members of Our Board of Directors and Our Special Board Advisors, and the Loss of Any Key Personnel, Board Member or Special Board Advisor Could Disrupt Our Business Operations.

Investors in our common stock must rely upon the ability, expertise, judgment and discretion of our management and the success of our technical team in identifying, evaluating and developing prospects and reserves. Our performance and success are dependent to a large extent on the efforts and continued employment of our management and technical personnel, including our Chairman, President and Chief Executive Officer, Joseph Wm. Foran. We do not believe that they could be quickly replaced with personnel of equal experience and capabilities, and their successors may not be as effective. We have entered into employment agreements with Mr. Foran and other key personnel. However, these employment agreements do not ensure that these individuals will remain in our employment. If Mr. Foran or any of these other key personnel resign or become unable to continue in their present roles and if they are not adequately replaced, our business operations could be adversely affected. With the exception of Mr. Foran, we do not maintain, nor do we plan to obtain, any insurance against the loss of any of these individuals.

We have an active board of directors that meets several times throughout the year and is intimately involved in our business and the determination of our operational strategies. Members of our board of directors work closely with management to identify potential prospects, acquisitions and areas for further development. Many of our directors have been involved with us since our inception and have a deep understanding of our operations and culture. If any of our directors resign or become unable to continue in their present role, it may be difficult to find replacements with the same knowledge and experience and as a result, our operations may be adversely affected.

In addition, our board consults regularly with our special advisors regarding our business and the evaluation, exploration, engineering and development of our prospects. Due to the knowledge and experience of our special advisors, they play a key role in our multi-disciplined approach to making decisions regarding prospects, acquisitions and development. If any of our special advisors resign or become unable to continue in their present role, our operations may be adversely affected.

Our Management Team Owns Approximately 13% of Our Common Stock Which Could Give Them Influence in Corporate Transactions and Other Matters, and the Interests of Our Management Could Differ from Other Shareholders.

Our directors and officers beneficially own approximately 13% of our outstanding shares of common stock. These shareholders are positioned to influence or control to some degree the outcome of matters requiring a shareholder vote, including the election of directors, the adoption of any amendment to our certificate of formation or bylaws and the approval of mergers and other significant corporate transactions. Their influence or control of the company may have the effect of delaying or preventing a change of control of the company and may adversely affect the voting and other rights of other shareholders. In addition, due to their ownership interest in our common stock, they may be able to remain entrenched in their positions.

Risks Relating to Our Common Stock

Our Common Stock Has Only Been Publicly Traded Since February 2, 2012, and the Price of our Common Stock Has Fluctuated Substantially Since Then and May Fluctuate Substantially in the Future.

Our common stock has been publicly traded only since February 2, 2012. The market price of our common stock could vary significantly as a result of a number of factors. In addition, the trading volume of our common stock may fluctuate and cause significant price variations to occur. In the event of a drop in the market price of our common stock, you could lose a substantial part or all of your investment in our common stock. In addition, the stock markets in general have experienced extreme volatility that has often been unrelated to the operating performance of particular companies. These broad market fluctuations may adversely affect the trading price of our common stock.

Factors that could affect our stock price or result in fluctuations in the market price or trading volume of our common stock include:

- our actual or anticipated operating and financial performance and drilling locations, including reserves estimates;
- quarterly variations in the rate of growth of our financial indicators, such as net income per share, net income and cash flows, or those of companies that are perceived to be similar to us;
- changes in revenue, cash flows or earnings estimates or publication of reports by equity research analysts;
- speculation in the press or investment community;
- public reaction to our press releases, announcements and filings with the Securities and Exchange Commission, or SEC;
- sales of our common stock by us or shareholders, or the perception that such sales may occur;

- general financial market conditions and oil and gas industry market conditions, including fluctuations in commodity prices;
- the realization of any of the risk factors presented in this report;
- the recruitment or departure of key personnel;
- commencement of or involvement in litigation;
- the prices of oil and natural gas;
- the success of our exploration and development operations, and the marketing of any oil and natural gas we produce;
- changes in market valuations of companies similar to ours; and
- domestic and international economic, legal and regulatory factors unrelated to our performance.

The Requirements of Being a Public Company, Including Compliance with the Reporting Requirements of the Securities Exchange Act of 1934, as Amended, and the Requirements of the Sarbanes-Oxley Act of 2002, May Strain Our Resources, Increase Our Costs and Distract Management; and It May Be Difficult to Comply with These Requirements in a Timely or Cost-Effective Manner.

As a new public company with listed equity securities, we are required to comply with laws, regulations and requirements, certain corporate governance provisions of the Sarbanes-Oxley Act of 2002, related regulations of the SEC and the requirements of the New York Stock Exchange, or the NYSE, with which we were not required to comply as a private company. Complying with these statutes, regulations and requirements will occupy a significant amount of time of our board of directors and management and will significantly increase our costs and expenses. We will need to:

- institute a more comprehensive compliance function;
- establish and maintain a system of internal controls over financial reporting in compliance with the requirements of Section 404 of the Sarbanes-Oxley Act and the related rules and regulations of the SEC;
- comply with rules promulgated by the NYSE;
- prepare and distribute periodic public reports in compliance with our obligations under the federal securities laws;
- establish new internal policies, such as those relating to disclosure controls and procedures and insider trading; and
- involve and retain to a greater degree outside counsel and accountants in the above activities.

In addition, as a result of being subject to these rules and regulations, we may have to accept less director and officer liability insurance coverage than we desire or to incur substantial costs to obtain acceptable coverage. These factors could also make it more difficult for us to attract and retain qualified members of our board of directors, particularly to serve on our Audit Committee, and qualified executive officers.

If Any of the Material Weaknesses Previously Identified by Our Independent Registered Public Accountants Persist or if We Fail to Establish and Maintain Effective Internal Control over Financial Reporting in the Future, Our Ability to Accurately Report Our Financial Results Could Be Adversely Affected.

Until February 1, 2012, we were a private company and maintained internal controls and procedures in accordance with being a private company. We have maintained limited accounting personnel to perform our accounting processes and limited supervisory resources with which to address our internal control over financial reporting. In connection with our audits for the years ended December 31, 2011 and 2010, our independent registered public accountants identified and communicated material weaknesses. In 2010, the material weaknesses related to controls over accounting and reporting for deferred income taxes, impairment of oil and natural gas properties, assessment of unproved and unevaluated properties and the administration of our stock and incentive plan. In 2011, the material weakness related only to accounting and reporting for stock compensation expense.

A material weakness is a control deficiency, or a combination of control deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of our annual and interim financial statements will not be prevented or detected and corrected on a timely basis. We have begun the process of evaluating our internal control over financial reporting and expect to put into place new accounting processes and control procedures to address the weaknesses described above, including the hiring of outside consultants to review significant or complex accounting issues and calculations, the implementation of a more formalized closing process, the formation of a disclosure committee and the hiring of additional personnel.

As a public company, we are required to comply with the SEC's rules implementing Sections 302 and 404 of the Sarbanes-Oxley Act, which require our management to certify financial and other information in our quarterly and annual reports and to provide an annual management report on the effectiveness of our internal control over financial reporting. We will be required to make our first assessment of our internal control over financial reporting for the year ended December 31, 2012. To comply with the requirements of being a public company, we are upgrading our systems, including information technology, implementing additional financial and management controls, reporting systems and procedures and have hired additional accounting and financial reporting staff.

Further, our independent registered public accountants are not yet required to formally attest to the effectiveness of our internal control over financial reporting. Once they are required to do so, our independent registered public accountants may issue a report that is adverse in the event they are not satisfied with the level at which our controls are documented, designed, operated or reviewed. Our remediation efforts may not enable us to remedy or avoid material weaknesses in the future.

Our efforts to develop and maintain our internal controls may not be successful, and we may be unable to maintain effective controls over our financial processes and reporting in the future and comply with the certification and reporting obligations under Sections 302 and 404 of the Sarbanes-Oxley Act. Further, our remediation efforts may not enable us to remedy or avoid material weaknesses in the future. Any failure to remediate deficiencies and to develop or maintain effective controls, or any difficulties encountered in our implementation or improvement of our internal control over financial reporting, could result in material misstatements that are not prevented or detected and corrected on a timely basis, which could potentially subject us to sanction or investigation by the SEC, the NYSE or other regulatory authorities. Ineffective internal controls could also cause investors to lose confidence in our reported financial information and adversely affect our business and our stock price.

We Do Not Presently Intend to Pay Any Cash Dividends on or Repurchase Any Shares of Our Common Stock.

We do not presently intend to pay any cash dividends on our common stock. Any payment of future dividends will be at the discretion of the 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. Cash dividend payments in the future may only be made out of legally available funds and, if we experience substantial losses, such funds may not be available. In addition, certain covenants in our credit agreement may limit our ability to pay dividends or repurchase shares of our common stock. Accordingly, you may have to sell some or all of your common stock in order to generate cash flow from your investment and there is no guarantee that the price of our common stock that will prevail in the market will exceed the price paid by you.

The Trading Volume in Our Common Stock Has Been Low, and the Sale of a Substantial Number of Shares in the Public Market Could Depress the Price of Our Common Stock.

Our common stock is listed on the NYSE, but since the completion of our initial public offering, it has had a relatively low average daily trading volume relative to many other stocks. Thinly traded stock can be more volatile than stock trading in an active public market, which can lead to significant price swings even when a relatively small number of shares are being traded and can limit an investor's ability to quickly sell blocks of stock. Shareholders holding more than 75% of our outstanding shares of common stock are subject to lockup agreements that prohibit the disposition of those shares until at least July 30, 2012, subject to certain exceptions. We cannot predict what effect, if any, the expiration of these lockups will have on future sales of our common stock in the market, including the availability of our common stock for sale in the market and the market price of our common stock.

Future Sales of Shares of Our Common Stock by Existing Shareholders and Future Offerings of Our Common Stock by Us Could Depress the Price of Our Common Stock.

The market price of our common stock could decline as a result of sales of a large number of shares of our common stock in the market, and the perception that these sales could occur may also depress the market price of our common stock. If our existing shareholders sell, or indicate an intent to sell, substantial amounts of our common stock in the public market after any contractual lockup and other legal restrictions on resale lapse, the trading price of our common stock could decline significantly. Sales of our common stock may make it more difficult for us to sell equity securities in the future at a time and at a price that we deem appropriate. These sales also could cause our stock price to fall and make it more difficult for you to sell shares of our common stock.

We may also sell additional shares of common stock or securities convertible into common stock in subsequent offerings. We cannot predict the size of future issuances of our common stock or convertible securities or the effect, if any, that future issuances and sales of shares of our common stock or convertible securities will have on the market price of our common stock.

Provisions of Our Certificate of Formation, Bylaws and Texas Law May Have Anti-Takeover Effects that Could Prevent a Change in Control Even if It Might Be Beneficial to Our Shareholders.

Our certificate of formation and bylaws contain certain provisions that may discourage, delay or prevent a merger or acquisition that our shareholders may consider favorable. These provisions include:

- authorization for our board of directors to issue preferred stock without shareholder approval;
- a classified board of directors so that not all members of our board of directors are elected at one time;
- the prohibition of cumulative voting in the election of directors; and
- a limitation on the ability of shareholders to call special meetings to those owning at least 25% of our outstanding shares of common stock.

Provisions of Texas law also may discourage, delay or prevent someone from acquiring or merging with us, which may cause the market price of our common stock to decline. Under Texas law, a shareholder who beneficially owns more than 20% of our voting stock, or any "affiliated shareholder," cannot acquire us for a period of three years from the date this person became an affiliated shareholder, unless various conditions are met, such as approval of the transaction by our board of directors before this person became an affiliated shareholder or approval of the holders of at least two-thirds of our outstanding voting shares not beneficially owned by the affiliated shareholder.

Our Board of Directors Can Authorize the Issuance of Preferred Stock, which Could Diminish the Rights of Holders of Our Common Stock, and Make a Change of Control of the Company More Difficult Even if It Might Benefit Our Shareholders.

Our board of directors is authorized to issue shares of preferred stock in one or more series and to fix the voting powers, preferences and other rights and limitations of the preferred stock. Accordingly, we may issue shares of preferred stock with a preference over our common stock with respect to dividends or distributions on liquidation or dissolution, or that may otherwise adversely affect the voting or other rights of the holders of common stock. Issuances of preferred stock, depending upon the rights, preferences and designations of the preferred stock, may have the effect of delaying, deterring or preventing a change of control of the company, even if that change of control might benefit our shareholders.

Item 1B. Unresolved Staff Comments.

Not applicable.

Item 2. Properties.

See "Business" for descriptions of our properties. We also have various operating leases for rental of office space, office and field equipment, and vehicles. See Note 12, *Commitments and Contingencies*, to the consolidated financial statements for the future minimum rental payments. Such information is incorporated herein by reference.

Item 3. Legal Proceedings.

Although we may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business, we are not currently a party to any material legal proceeding. In addition, we are not aware of any material legal or governmental proceedings against us, or contemplated to be brought against us.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

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

General Market Information

On February 2, 2012, our common stock began trading on the NYSE under the symbol "MTDR." On February 7, 2012, we completed our initial public offering of 14,883,334 shares of common stock at $12.00 per share. We sold 12,209,167 shares of common stock in this offering, and certain selling shareholders sold 2,674,167 shares of common stock, including shares sold by us and the selling shareholders pursuant to the partial exercise of the underwriters' over-allotment on March 7, 2012. Prior to trading on the NYSE, there was no established public trading market for our common stock.

On March 30, 2012, we had 55,272,860 shares of common stock outstanding held by approximately 516 record holders, excluding shareholders for whom shares are held in "nominee" or "street" name.

The following table sets forth the high and low sales prices of our common stock as reported by the NYSE for the period indicated:

	High	Low
Period from February 2, 2012 to March 30, 2012	$12.33	$10.85

On March 30, 2012, the last reported sales price of our common stock on the NYSE was $10.95 per share.

Dividend Policy

We do not anticipate declaring or paying any cash dividends to holders of our common stock in the foreseeable future. We currently intend to retain future earnings to finance the expansion of our business. Our future dividend policy is within the discretion of our board of directors and will depend upon various factors, including our results of operations, financial condition, capital requirements and investment opportunities. In addition, certain covenants in our credit agreement may limit our ability to pay dividends on our common stock.

Prior to consummation of our initial public offering, the holders of our Class B common stock were entitled to be paid cumulative dividends at a per share rate of $0.26-2/3 annually out of funds legally available for the payment of dividends. These dividends accrued and were payable quarterly at the rate of $0.06-2/3 per share of Class B common stock outstanding. For the years ended December 31, 2011, 2010 and 2009, we declared dividends on our outstanding shares of Class B common stock totaling $274,853 in each year. Upon the automatic conversion of the outstanding shares of Class B common stock at the closing of our initial public offering, the right of the holders of Class B common stock to dividends was terminated and such holders were paid approximately $28,000 during the first quarter of 2012 for all accrued but unpaid dividends existing at the time of such conversion.

Equity Compensation Plan Information

The following table presents the securities authorized for issuance under our equity compensation plans as of December 31, 2011.

Equity Compensation Plan Information

Plan Category	Number of Shares to be Issued Upon Exercise of Outstanding Options, Warrants and Rights	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights ($)	Number of Shares Remaining Available for Future Issuance Under Equity Compensation Plans
Equity compensation plans approved by security holders(1)	1,024,500	$9.75	–
Equity compensation plans not approved by security holders(2)	–	–	4,000,000
Total	1,024,500	$9.75	4,000,000

(1) Our board of directors has determined not to make any additional grants of awards under the Matador Resources Company 2003 Stock and Incentive Plan.

(2) Our 2012 Long-Term Incentive Plan was approved by our board of directors in December 2011 and took effect on January 1, 2012. For a description of our 2012 Long-Term Incentive Plan, see Note 17 to our consolidated financial statements included elsewhere in this Form 10-K.

Recent Sales of Unregistered Securities

From October 2010 through January 2011, we sold 1,922,199 shares of our common stock to accredited investors for the aggregate consideration of $21,144,189. These shares were issued in a transaction exempt from the registration requirements of the Securities Act under Section 4(2) of the Securities Act and Rule 506.

During 2011, we issued an aggregate of 93,001 shares of common stock pursuant to the exercise of stock options held by certain directors and employees and received an aggregate of $837,009 for such exercises. The issuance of these shares was exempt from the registration requirements of the Securities Act pursuant to Rule 701.

During 2011, we issued an aggregate of 17,500 shares of our common stock to our outside directors and advisors in connection with their service to the board. These shares were issued in transactions exempt from the registration requirements of the Securities Act under Section 4(2) of the Securities Act.

In October 2011, we issued an aggregate of 2,575 shares of our common stock to General Mills, Inc. Benefits Finance Committee on behalf of General Mills Group Trust and Voluntary Employees Beneficiary Assoc. Trust General Mills & Bakery, Confectionary, Tobacco & Grain Millers in connection with prior service on the board by officers of General Mills, Inc. Benefits Finance Committee. These shares were issued in transactions exempt from the registration requirements of the Securities Act under Section 4(2) of the Securities Act.

Use of Proceeds

Our initial public offering of common stock was effected through a Registration Statement on Form S-1 (File No. 333-176263), which was declared effective by the SEC on February 1, 2012. RBC Capital Markets, LLC; Citigroup Global Markets Inc.; Jefferies & Company, Inc.; Howard Weil Incorporated; Stifel, Nicolaus & Company, Incorporated; Stephens Inc.; and Comerica Securities, Inc. acted as underwriters for the offering. RBC Capital Markets, LLC and Citigroup Global Markets Inc. acted as the co-managers for the offering. Under the Form S-1, we registered the offer and sale of an aggregate of 15,333,334 shares of our common stock, 12,209,167 shares of which were issued and sold by us and 2,674,167 shares of which were sold by the selling shareholders named in the Form S-1, including shares sold by us and certain of the selling shareholders pursuant to the partial exercise of the underwriters' option to purchase additional shares. The initial public offering closed on February 7, 2012 and the over-allotment option closed on March 7, 2012. We issued and sold all but 450,000 of the shares that were registered.

The shares were sold at a price to the public of $12.00 per share and we received cash proceeds of approximately $133.6 million from this transaction, net of underwriting discounts and commissions. We did not receive any proceeds from the sale of shares by the selling shareholders. The underwriters received underwriting discounts and commissions totaling approximately $9.9 million, and we incurred additional costs of approximately $3.0 million in connection with the offering, which amounted to total fees and costs of approximately $12.9 million. No offering costs were paid directly or indirectly to any of our directors or officers (or their associates) or persons owning 10% or more of any class of our equity securities or to any other affiliates, other than advancement of legal fees for one counsel to represent the selling shareholders.

We used $123.0 million to repay the then outstanding borrowings under our credit agreement. We used the remaining proceeds to fund a portion of our 2012 capital expenditure requirements.

Item 6. Selected Financial Data.

You should read the following selected financial data in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" and our historical consolidated financial statements and related notes thereto included elsewhere in this report. The financial information included in this report may not be indicative of our future results of operations, financial position or cash flows.

The following selected financial information is summarized from our results of operations for the five-year period ended December 31, 2011 and selected consolidated balance sheet data at December 31, 2011, 2010, 2009, 2008 and 2007 and should be read in conjunction with the consolidated financial statements at the years ended December 31, 2011, 2010 and 2009 included herewith.

	Year Ended December 31,				
	2011	2010	2009	2008	2007
(In thousands)					
Statement of operations data:					
Revenues:					
Oil and natural gas revenues	$ 67,000	$34,042	$ 19,039	$ 30,645	$13,988
Realized gain (loss) on derivatives	7,106	5,299	7,625	(1,326)	213
Unrealized gain (loss) on derivatives	5,138	3,139	(2,375)	3,592	(211)
Total revenues	79,244	42,480	24,289	32,911	13,990
Expenses:					
Production taxes and marketing	6,278	1,982	1,077	1,639	779
Lease operating	7,244	5,284	4,725	4,667	3,099
Depletion, depreciation and amortization	31,754	15,596	10,743	12,127	7,889
Accretion of asset retirement obligations	209	155	137	92	70
Full-cost ceiling impairment	35,673	–	25,244	22,195	–
General and administrative	13,394	9,702	7,115	8,252	5,189
Total expenses	94,552	32,719	49,041	48,972	17,026
Operating (loss) income	(15,308)	9,761	(24,752)	(16,061)	(3,036)
Other (expense) income:					
Net (loss) gain on asset sales and inventory impairment	(154)	(224)	(379)	136,977	–
Interest expense	(683)	(3)	–	–	–
Interest and other income	315	364	781	2,984	2,736
Total other (expense) income	(522)	137	402	139,962	2,736
Net (loss) income	$(10,309)	$ 6,377	$(14,425)	$103,878	$ (300)
Earnings (loss) per common share					
Basic					
Class A	$ (0.25)	$ 0.15	$ (0.37)	$ 2.50	$ (0.05)
Class B	$ 0.02	$ 0.42	$ (0.10)	$ 2.77	$ 0.22
Diluted					
Class A	$ (0.25)	$ 0.15	$ (0.37)	$ 2.46	$ (0.05)
Class B	$ 0.02	$ 0.42	$ (0.10)	$ 2.73	$ 0.22
Class B dividend declared, per share	$ 0.27	$ 0.27	$ 0.27	$ 0.27	$ 0.27

(In thousands)	At December 31, 2011	2010	2009	2008	2007
Balance sheet data:					
Cash and cash equivalents	$ 10,284	$ 21,060	$104,230	$ 150,768	$ 9,017
Certificates of deposit	1,335	2,349	15,675	20,782	–
Short-term investments	–	–	–	–	57,925
Net property and equipment	399,865	303,880	142,078	125,261	105,814
Total assets	439,469	346,382	277,400	314,539	179,152
Current liabilities	74,576	30,097	8,868	35,475	5,541
Long term liabilities	93,377	34,408	4,210	2,059	1,568
Total shareholders' equity	$ 271,515	$ 281,877	$264,321	$ 277,005	$ 172,043

	Year Ended December 31, 2011	2010	2009	2008	2007
Other financial data:					
Net cash provided by operating activities	$ 61,868	$ 27,273	$ 1,791	$ 25,851	$ 7,881
Net cash (used in) provided by investing activities	(160,088)	(147,334)	(49,415)	115,481	(108,296)
Oil and natural gas properties capital expenditures	(156,431)	(159,050)	(54,244)	(104,119)	(50,310)
Expenditures for other property and equipment	(4,671)	(1,610)	(307)	(3,012)	(1,300)
Net cash provided by financing activities	87,444	36,891	1,086	419	66,250
Adjusted EBITDA[1]	$ 49,911	$ 23,635	$ 15,184	$ 18,411	$ 8,090

(1) Adjusted EBITDA is a non-GAAP financial measure. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to our net income (loss) and net cash provided by operating activities, see "Non-GAAP Financial Measures" below.

Non-GAAP Financial Measures

We define Adjusted EBITDA as earnings before interest expense, income taxes, depletion, depreciation and amortization, accretion of asset retirement obligations, property impairments, unrealized derivative gains and losses, non-recurring income and expenses and non-cash stock-based compensation expense, including stock option and grant expense and restricted stock grants. Adjusted EBITDA is not a measure of net income or cash flows as determined by GAAP. Adjusted EBITDA is a supplemental non-GAAP financial measure that is used by management and external users of our consolidated financial statements, such as industry analysts, investors, lenders and rating agencies.

Management believes Adjusted EBITDA is necessary because it allows us to evaluate our operating performance and compare the results of operations from period to period without regard to our financing methods or capital structure. We exclude the items listed above from net income (loss) in calculating Adjusted EBITDA because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which certain assets were acquired.

Adjusted EBITDA should not be considered an alternative to, or more meaningful than, net income or cash flows from operating activities as determined in accordance with GAAP or as an indicator of our operating performance or liquidity. Certain items excluded from Adjusted EBITDA are significant components of understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure. Our Adjusted EBITDA may not be comparable to similarly titled measures of another company because all companies may not calculate Adjusted EBITDA in the same manner. The following table presents our calculation of Adjusted EBITDA and the reconciliation of Adjusted EBITDA to the GAAP financial measures of net income (loss) and net cash provided by operating activities, respectively.

(In thousands)	2011	2010	2009	2008	2007
	Year Ended December 31,				
Unaudited Adjusted EBITDA reconciliation to Net Income (Loss):					
Net (loss) income	$(10,309)	$ 6,377	$(14,425)	$ 103,878	$ (300)
Interest expense	683	3	–	–	–
Total income tax (benefit) provision	(5,521)	3,521	(9,925)	20,023	–
Depletion, depreciation and amortization	31,754	15,596	10,743	12,127	7,889
Accretion of asset retirement obligations	209	155	137	92	70
Full-cost ceiling impairment	35,673	–	25,244	22,195	–
Unrealized (gain) loss on derivatives	(5,138)	(3,139)	2,375	(3,592)	211
Stock option and grant expense	2,362	824	622	605	205
Restricted stock grants	44	74	34	60	15
Net loss (gain) on asset sales and inventory impairment	154	224	379	(136,977)	–
Adjusted EBITDA	$ 49,911	$23,635	$ 15,184	$ 18,411	$8,090

(In thousands)	2011	2010	2009	2008	2007
	Year Ended December 31,				
Unaudited Adjusted EBITDA reconciliation to Net Cash Provided by Operating Activities:					
Net cash provided by operating activities	$ 61,868	$27,273	$ 1,791	$ 25,851	$7,881
Net change in operating assets and liabilities	(12,594)	(2,230)	15,717	(17,888)	209
Interest expense	683	3	–	–	–
Current income tax (benefit) provision	(46)	(1,411)	(2,324)	10,448	–
Adjusted EBITDA	$ 49,911	$23,635	$15,184	$ 18,411	$8,090

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our consolidated financial statements and related notes appearing elsewhere in this report. The following discussion contains "forward-looking statements" that reflect our future plans, estimates, beliefs and expected performance. We caution that assumptions, expectations, projections, intentions or beliefs about future events may, and often do, vary from actual results and the differences can be material. Some of the key factors which could cause actual results to vary from our expectations include changes in oil or natural gas prices, the timing of planned capital expenditures, availability of acquisitions, uncertainties in estimating proved reserves and forecasting production results, operational factors affecting the commencement or maintenance of producing wells, the condition of the capital markets generally, as well as our ability to access them, the proximity to and capacity of transportation facilities, uncertainties regarding environmental regulations or litigation and other legal or regulatory developments affecting our business, as well as those factors discussed below and elsewhere in this report, all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. See "Cautionary Note Regarding Forward-Looking Statements."

Overview

We are an independent energy company engaged in the exploration, development, production and acquisition of oil and natural gas resources in the United States, with a particular emphasis on oil and natural gas shale plays and other unconventional resource plays. Our current operations are located primarily in the Eagle Ford shale play in south Texas and the Haynesville shale play in northwest Louisiana and east Texas. We expect the majority of our near-term capital expenditures will focus primarily on increasing our production and reserves from the Eagle Ford shale play. We believe our interests in the Eagle Ford shale play will enable us to create a more balanced commodity portfolio through the drilling of locations that are prospective for oil and liquids. In addition to these primary operating areas, we have acreage positions in southeast New Mexico and west Texas and in southwest Wyoming and adjacent areas in Utah and Idaho where we continue to identify new oil and natural gas prospects.

We were founded in July 2003 by Mr. Joseph Wm. Foran and Mr. Scott E. King, and we drilled our first well in 2004. Since that time, we have drilled or participated in drilling 236 wells through December 31, 2011, including 106 Haynesville and nine Eagle Ford wells. At December 31, 2011, based on the reserves audit by our independent reservoir engineers, we had 193.2 Bcfe of estimated proved reserves with a PV-10 of $248.7 million and a Standardized Measure of $215.5 million. At December 31, 2011, 34% of our estimated proved reserves were proved developed reserves, 12% of our estimated proved reserves were oil and 88% of our estimated proved reserves were natural gas. Our average daily production for the year ended December 31, 2011 was 42.3 MMcfe per day, including 39.8 MMcf of natural gas per day and 422 Bbl of oil per day, as compared to an average daily production of 23.6 MMcfe per day, including 23.0 MMcf of natural gas per day and 91 Bbl of oil per day for the year ended December 31, 2010. We have achieved this growth while lowering operating costs (consisting of lease operating expenses and production taxes and marketing expenses) from $1.16 per Mcfe for the year ended December 31, 2009 to $0.88 per Mcfe for the year ended December 31, 2011, or a decrease of approximately 24%.

Our business success and financial results are dependent on many factors beyond our control, such as economic, political and regulatory developments, as well as competition from other sources of energy. Commodity price volatility, in particular, is a significant risk factor for us. Commodity prices are affected by changes in market supply and demand, which is impacted by overall economic activity, weather, pipeline capacity constraints, inventory storage levels, natural gas price differentials and other factors. Prices for oil and natural gas will affect the cash flows available to us for capital expenditures and our ability to borrow and raise additional capital. Declines in oil or natural gas prices would not only reduce our revenues, but could also reduce the amount of oil and/or natural gas that we can produce economically, and as a result, could have an adverse effect on our financial condition, results of operations, cash flows and reserves.

In response to the recent commodity price environment, and in particular, the general decline in natural gas prices since July 2008 in contrast with the rebound in oil prices since February 2009, we have sought to balance our exploration and development plans by targeting more oil prone reservoirs, such as the Eagle Ford shale. While most of our historical and current production is natural gas, we believe that our future production profile will reflect a more balanced oil and natural gas commodity mix as a result of our strategic shift to target more oil development than we have historically.

In recent months, natural gas prices have declined to their lowest levels in many years, and at March 30, 2012, the NYMEX Henry Hub natural gas futures contract for the earliest delivery date closed at $2.13 per MMBtu. We would not expect to drill any operated natural gas wells, except for natural gas wells in specific exploratory prospects like the Meade Peak shale, until natural gas prices improved substantially from these levels or unless the costs to drill and complete these wells were also to decline substantially from their recent levels. See "Risk Factors – Our Identified Drilling Locations Are Scheduled Out Over Several Years, Making Them Susceptible to Uncertainties That Could Materially Alter the Occurrence or Timing of Their Drilling."

During 2012, we intend to allocate 84% of our 2012 capital expenditure budget of $313.0 million to the exploration, development and acquisition of additional interests in the Eagle Ford shale play. Including these anticipated capital expenditures in the Eagle Ford shale, we plan to dedicate about 94% of our 2012 anticipated capital expenditure budget to opportunities prospective for oil and liquids production. While we have budgeted $313.0 million for 2012, the aggregate amount of capital we will expend may fluctuate materially based on market conditions and our drilling results.

As we transition our operations from the Haynesville shale and Cotton Valley in northwest Louisiana to the Eagle Ford shale in south Texas, we may face challenges associated with establishing operations and securing the necessary services to drill and complete wells and with securing the necessary pipeline and natural gas processing capabilities to transport, process and market the oil and natural gas that we produce. We may also incur higher than anticipated costs associated with establishing new operating infrastructure and facilities on our leases throughout the area. We believe we have successfully secured the necessary drilling and completion services for our current Eagle Ford operations, and at March 30, 2012, we had two contracted drilling rigs operating in south Texas: one in LaSalle County and one in Karnes County. We are not currently experiencing difficulties in securing completion, and particularly hydraulic fracturing services, for our newly drilled wells, although we experienced these problems at various times during 2011 in south Texas and may have such difficulties again in the future. We believe that maintaining reliable and timely drilling and completion services and reducing drilling and completion costs will be essential to the successful development and profitability of the Eagle Ford shale play. See "Risk Factors – The Unavailability or High Cost of Drilling Rigs, Completion Equipment and Services, Supplies and Personnel, Including Hydraulic Fracturing Equipment and Personnel, Could Adversely Affect Our Ability to Establish and Execute Exploration and Development Plans within Budget and on a Timely Basis, Which Could Have a Material Adverse Effect on Our Financial Condition, Results of Operations and Cash Flows."

We experienced temporary pipeline interruptions from time to time during 2011 associated with natural gas production from our Eagle Ford wells and have been required to either shut in wells for brief periods or to flare some of the natural gas we produce. At March 30, 2012, we were experiencing pipeline capacity limitations at our Martin Ranch lease in LaSalle County and are currently flaring a portion of the natural gas we are producing there as a result. We believe that these pipeline interruptions and capacity constraints are temporary and that additional oil and natural gas pipeline infrastructure currently being built throughout south Texas will help to alleviate these problems within 60 to 90 days. If we were required to shut in our production for long periods of time due to these pipeline interruptions, it could have a material adverse effect on our business, financial condition, results of operations and cash flows. See "Risk Factors – The Marketability of Our Production Is Dependent Upon Oil and Natural Gas Gathering and Transportation Facilities Owned and Operated by Third Parties, and the Unavailability of Satisfactory Oil and Natural Gas Transportation Agreements Would Have a Material Adverse Effect on Our Revenue."

On February 2, 2012, our common stock began trading on the NYSE under the symbol "MTDR." We believe that our general and administrative expenses will increase as a result of us operating as a public company. This increase will consist primarily of legal and accounting fees and additional expenses associated with compliance with the Sarbanes-Oxley Act and other regulations and increases in our staff compensation and other ongoing general and administrative expenses necessary to maintain and grow a publicly traded exploration and production company. A large part of this increase will be due to the cost of accounting and legal support services, filing annual and quarterly reports with the SEC, investor relations activities, directors' fees, incremental directors' and officers' liability insurance costs and transfer and registrar agent fees. As a result, we believe that our general and administrative expenses for future periods will increase significantly. Our consolidated financial statements for future periods will reflect the impact of these increased expenses and affect the comparability of our financial statements with periods before the completion of this offering.

Revenues

Our revenues are derived primarily from the sale of oil and natural gas production. Our revenues may vary significantly from period to period as a result of changes in volumes of production sold or changes in oil or natural gas prices.

Realized gain (loss) on derivatives. We use commodity derivative financial instruments to mitigate our exposure to fluctuations in oil and natural gas prices. This revenue item includes the net realized cash gains and losses associated with the settlement of these derivative financial instruments for a given reporting period.

Unrealized gain (loss) on derivatives. We use commodity derivative financial instruments to mitigate our exposure to fluctuations in oil and natural gas prices. This revenue item recognizes the non-cash change in the fair value of our open derivative contracts between reporting periods.

The following table summarizes our revenues and production data for the periods indicated:

	Year Ended December 31,		
	2011	2010	2009
Operating Results:			
Revenues (in thousands):			
Oil	$14,457	$ 2,507	$ 1,719
Natural gas	52,543	31,535	17,320
Total oil and natural gas revenues	67,000	34,042	19,039
Realized gain (loss) on derivatives	7,106	5,299	7,625
Unrealized gain (loss) on derivatives	5,138	3,139	(2,375)
Total revenues	$79,244	$42,480	$24,289
Net Production Volumes:			
Oil (MBbls)	154	33	30
Natural gas (Bcf)	14.5	8.4	4.8
Total natural gas equivalents (Bcfe) (1)	15.4	8.6	5.0
Average net daily production (MMcfe/d) (1)	42.3	23.6	13.7
Average Sales Prices:			
Oil (per Bbl)	$ 93.80	$ 76.39	$ 57.72
Natural gas, with realized derivatives (per Mcf)	$ 4.11	$ 4.38	$ 5.17
Natural gas, without realized derivatives (per Mcf)	$ 3.62	$ 3.75	$ 3.59

(1) Estimated using a conversion ratio of one Bbl per six Mcf.

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

Oil and natural gas revenues. Our oil and natural gas revenues increased by $33.0 million to $67.0 million, or an increase of about 97%, for the year ended December 31, 2011 as compared to the year ended December 31, 2010. This increase in oil and natural gas revenues corresponds with an increase of about 79% in our oil and natural gas production to 15.4 Bcfe for the year ended December 31, 2011 from 8.6 Bcfe for the year ended December 31, 2010. This increased production was almost entirely due to drilling operations in the Eagle Ford and Haynesville shales. A portion of the increase in oil and natural gas revenues reflects the approximate five-fold increase in our oil production for the year ended December 31, 2011 as compared to the year ended December 31, 2010, as well as a higher average oil price of $93.80 per Bbl realized during 2011 as compared to an average oil price of $76.39 per Bbl realized during 2010.

Realized gain (loss) on derivatives. Our realized gain on derivatives increased by approximately $1.8 million to $7.1 million for the year ended December 31, 2011 from $5.3 million for the year ended December 31, 2010. The realized gain from our open natural gas costless collar contracts increased primarily as a result of the decline in natural gas prices during the comparable periods. We realized approximately $1.03 per MMBtu hedged on all of our open natural gas costless collar contracts during the year ended December 31, 2011 as compared to $0.89 per MMBtu hedged on all of our open natural gas costless collar contracts during the year ended December 31, 2010. Our total natural gas volumes hedged for the year ended December 31, 2011 were also approximately 16% higher than the total natural gas volumes hedged for 2010.

Unrealized gain (loss) on derivatives. Our unrealized gain on derivatives was approximately $5.14 million for the year ended December 31, 2011 as compared to an unrealized gain of $3.14 million for the year ended December 31, 2010. During the period from December 31, 2010 to December 31, 2011, the net fair value of our open natural gas costless collar contracts increased from approximately $4.14 million to approximately $9.28 million, resulting in an unrealized gain on derivatives of approximately $5.14 million for the year ended December 31, 2011. This increase in the net fair value of our open natural gas costless collar contracts was due primarily to a decrease in natural gas prices during 2011 as compared to 2010, as well as an increase in the total number of our open contracts at December 31, 2011 as compared to December 31, 2010.

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

Oil and natural gas revenues. Our oil and natural gas revenues increased by $15.0 million to $34.0 million, or an increase of about 79%, for the year ended December 31, 2010 as compared to the year ended December 31, 2009. Approximately $13.7 million of the increase was primarily due to a 72% increase in our production to 8.6 Bcfe during the year ended December 31, 2010 from 5.0 Bcfe during the year ended December 31, 2009, and approximately $1.3 million of the increase was due to increases in the average prices we received for both oil and natural gas over these respective periods. For the year ended December 31, 2010, we received an average natural gas price of $3.75 per Mcf and an average oil price of $76.39 per Bbl as compared to an average natural gas price of $3.59 per Mcf and an average oil price of $57.72 per Bbl for the year ended December 31, 2009. Our increased production during this period was primarily due to drilling operations in the Haynesville shale.

Realized gain (loss) on derivatives. Our realized gain on derivatives decreased by approximately $2.3 million to $5.3 million for the year ended December 31, 2010 from $7.6 million for the year ended December 31, 2009. This decrease was due primarily to a decrease of about $1.50 per MMBtu in the average price floor of our open natural gas costless collar contracts in 2010 as compared with 2009 and despite the fact that we had almost twice the natural gas volumes hedged in 2010 as compared to 2009.

Unrealized gain (loss) on derivatives. Our unrealized gain on derivatives was $3.14 million for the year ended December 31, 2010, compared to an unrealized loss of $2.38 million for the year ended December 31, 2009. During the period from December 31, 2009 to December 31, 2010, the net fair value of our open natural gas costless collar contracts increased from $1.00 million to $4.14 million, resulting in an unrealized gain on derivatives of $3.14 million for the year ended December 31, 2010. This increase in the net fair value of our open natural gas costless collar contracts was due primarily to lower natural gas prices at December 31, 2010 as compared to December 31, 2009.

Expenses

Production taxes and marketing. Production taxes are paid on produced oil and natural gas based on a percentage of revenues from products sold at market prices (not hedged prices) or at fixed rates established by federal, state or local taxing authorities. We attempt to take advantage of all credits and exemptions in our various taxing jurisdictions. In general, the production taxes we pay tend to correlate to the changes in our oil and natural gas revenues. Marketing expenses are fees charged by the purchasers of the oil and natural gas we produce and sell and principally include marketing, compression and transportation fees.

Lease operating expenses. Lease operating expenses are the daily costs incurred to produce oil and natural gas, as well as the daily costs incurred to maintain our producing properties. Such costs also include field personnel costs, utilities, chemical additives, salt water disposal, maintenance, repairs and occasional workover expenses related to our oil and natural gas properties.

Depletion, depreciation and amortization. Depletion, depreciation and amortization includes the systematic expensing of the capitalized costs incurred in the acquisition, exploration and development of oil and natural gas. We use the full-cost method of accounting and accordingly, we capitalize all costs associated with the acquisition, exploration and development of oil and natural gas properties, including unproved and unevaluated property costs. Internal costs are capitalized only to the extent they are directly related to acquisition, exploration or development activities and do not include any costs related to production, selling or general corporate administrative activities. Capitalized costs of oil and natural gas properties are amortized using the unit-of-production method based upon production and estimates of proved oil and natural gas reserves quantities. Unproved and unevaluated property costs are excluded from the amortization base used to determine depletion, depreciation and amortization.

Accretion of asset retirement obligations. Asset retirement obligations relate to the future costs associated with plugging and abandonment of oil and natural gas wells, removal of equipment and facilities from leased acreage and returning such land to its original condition. We recognize the fair value of an asset retirement obligation in the period it is incurred if a reasonable estimate of fair value can be made. The asset retirement obligation is recorded as a liability at its estimated present value, with an offsetting increase recognized in oil and natural gas properties or support equipment and facilities on the balance sheet. Periodic accretion of the discounted value of the estimated liability is recorded as an expense in our statement of operations.

Full-cost ceiling impairment. The net capitalized costs of oil and natural gas properties are limited to the lower of unamortized costs less related deferred income taxes or the cost center ceiling, with any excess above the cost center ceiling charged to operations as a full-cost ceiling impairment. The cost center ceiling is defined as the sum of (a) the present value discounted at 10 percent of future net revenues of proved oil and natural gas reserves, plus (b) unproved and unevaluated property costs not being amortized, plus (c) the lower of cost or estimated fair value of unproved and unevaluated properties included in the costs being amortized, if any, less (d) income tax effects related to the properties involved. Future net revenues from proved non-producing and proved undeveloped reserves are reduced by the estimated costs of developing these reserves. The fair value of our derivative instruments is not included in the ceiling test computation as we do not designate these instruments as hedge instruments for accounting purposes.

General and administrative expenses. General and administrative expenses include, but are not limited to, compensation and benefits for our employees, costs of renting and maintaining our headquarters, office service contracts, board of directors fees, franchise taxes, stock-based compensation expense and accounting, legal and other professional fees.

Other Income (Expense)

Net gain (loss) on asset sales and inventory impairment. This other income (expense) item includes the net gain or loss we experience on infrequent asset sales or impairment charges associated with certain equipment held in inventory. This item also includes infrequent sales of oil and natural gas properties that we consider to be extraordinary when considered in relation to the normal course of our business.

Interest expense. Interest expense includes interest paid to our lenders as a result of borrowings under our revolving credit agreement. We finance a portion of our working capital requirements, capital expenditures and acquisitions with borrowings under the credit agreement, and as a result, we incur interest expense that is affected by both fluctuations in interest rates and our financing decisions. In addition, we include any amortization of deferred financing costs (including origination and amendment fees), commitment or facility fees and annual agency fees as interest expense.

Interest and other income. Interest income includes interest earned periodically on the cash and cash equivalents we hold in money market accounts composed of United States Treasury securities offering daily liquidity and the interest earned periodically on our certificates of deposit. Other income includes income we receive for providing salt water disposal and natural gas transportation services to other working interest participants in wells that we operate.

Total income tax provision (benefit). Total income tax provision (benefit) includes the net current and deferred portions of our estimated income tax liabilities. We file a United States federal income tax return and state tax returns in those states where we conduct oil and natural gas operations. The current portion of our income tax provision (benefit) reflects actual income tax payments made or refunds received by us as a result of filing these income tax returns. The deferred portion of our income tax provision is the result of temporary timing differences between the financial statement carrying values and the tax bases of our assets and liabilities.

The following table summarizes our operating expenses and other income (expense) for the periods indicated:

	Year Ended December 31,		
	2011	2010	2009
(In thousands, except expenses per Mcfe)			
Expenses:			
Production taxes and marketing	$ 6,278	$ 1,982	$ 1,077
Lease operating	7,244	5,284	4,725
Depletion, depreciation and amortization	31,754	15,596	10,743
Accretion of asset retirement obligations	209	155	137
Full-cost ceiling impairment	35,673	–	25,244
General and administrative	13,394	9,702	7,115
Total expenses	94,552	32,719	49,041
Operating (loss) income	(15,308)	9,761	(24,752)
Other (expense) income:			
Net loss on asset sales and inventory impairment	(154)	(224)	(379)
Interest expense	(683)	(3)	–
Interest and other income	315	364	781
Total other (expense) income	(522)	137	402
(Loss) income before income taxes	(15,830)	9,898	(24,350)
Total income tax (benefit) provision	(5,521)	3,521	(9,925)
Net (loss) income	$(10,309)	$ 6,377	$(14,425)
Expenses per Mcfe:			
Production taxes and marketing	$ 0.41	$ 0.23	$ 0.22
Lease operating	$ 0.47	$ 0.61	$ 0.94
Depletion, depreciation and amortization	$ 2.06	$ 1.81	$ 2.15
General and administrative	$ 0.87	$ 1.13	$ 1.42

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

Production taxes and marketing. Our production taxes and marketing expenses increased by $4.3 million to $6.3 million, or an increase of approximately 217% for the year ended December 31, 2011 as compared to the year ended December 31, 2010. The increase in our production taxes and marketing expenses reflects the increases in both our oil and natural gas production and revenues by 79% and 97%, respectively, during the year ended December 31, 2011 as compared to the year ended December 31, 2010. The majority of this increase was due to higher marketing, transportation and compression charges on portions of our non-operated Haynesville shale production in 2011 as compared to 2010. Some of this increase was also due to Haynesville shale wells completed in 2011, several of which were turned to sales or produced their first significant production volumes during 2011. Although we or our outside operating partners have applied for exemptions from initial production taxes on these recently completed Haynesville shale wells, and although we expect these applications will be approved by the state of Louisiana, some of these wells had not yet been approved for production tax exemptions at December 31, 2011. Thus, we have paid and/or accrued for the associated production taxes on these wells during the year ended December 31, 2011, although we expect these production taxes will be refunded to us in future periods. We will adjust our production taxes and marketing expenses accordingly when and if these production tax exemptions are approved. The remainder of the increase in production taxes and marketing expenses for the year ended December 31, 2011 was due to production taxes paid on production from our initial Eagle Ford shale wells in south Texas.

Lease operating expenses. Our lease operating expenses increased by $2.0 million to $7.2 million, or an increase of about 37%, for the year ended December 31, 2011 as compared to the year ended December 31, 2010. During these respective periods, however, our oil and natural gas production increased 79% from 8.6 Bcfe to 15.4 Bcfe. As a result, our lease operating expenses per unit of production decreased by 23% to $0.47 per Mcfe for the year ended December 31, 2011 as compared to $0.61 per Mcfe for the year ended December 31, 2010. During the year ended December 31, 2011, both our total Haynesville shale production, as well as the percentage of our Haynesville production for which we were the operator increased, as compared to the year ended December 31, 2010. The unit lease operating costs associated with the Haynesville production are much less than those associated with our Cotton Valley natural gas production, primarily due to the greater salt water disposal costs associated with the Cotton Valley production and given the early stages of production associated with many of these Haynesville wells.

Depletion, depreciation and amortization. Our depletion, depreciation and amortization expenses increased by $16.2 million to $31.8 million, or an increase of about 104%, for the year ended December 31, 2011 as compared to the year ended December 31, 2010. The increase in our depletion, depreciation and amortization expenses was due primarily to an increase of approximately 79% in our oil and natural gas production from 8.6 Bcfe to 15.4 Bcfe during the respective time periods. Our depletion, depreciation and amortization expenses on a unit-of-production basis increased to $2.06 for the year ended December 31, 2011, or an increase of about 14%, from $1.81 per Mcfe for the year ended December 31, 2010. This per unit increase reflects increases in drilling and completion costs for wells drilled to the Haynesville shale during 2011, as well as higher drilling and completion costs on a per Mcfe basis associated with oil reserves added in the Eagle Ford shale in south Texas.

Accretion of asset retirement obligations. Our accretion of asset retirement obligations expenses increased by approximately $54,000 to approximately $209,000, or an increase of about 35%, for the year ended December 31, 2011 as compared to the year ended December 31, 2010. The increase in our accretion of asset retirement obligations was due primarily to the addition of new wells through our drilling of operated wells and our participation in the drilling of non-operated wells, although, on the whole, this item is an insignificant component of our overall expenses.

Full-cost ceiling impairment. During the quarter ended March 31, 2011, the net capitalized costs of our oil and natural gas properties less related deferred income taxes exceeded the cost center ceiling by $23.0 million. As a result, we recorded an impairment charge of $35.7 million to the net capitalized costs of our oil and natural gas properties and a deferred income tax credit of $12.7 million, which is reflected in our expenses for the year ended December 31, 2011. No impairment to the net carrying value of our oil and natural gas properties on the balance sheet resulting from the full-cost ceiling limitation was recorded at December 31, 2010.

General and administrative. Our general and administrative expenses increased by $3.7 million to $13.4 million, or an increase of about 38%, for the year ended December 31, 2011 as compared to the year ended December 31, 2010. The increase in our general and administrative expenses was due primarily to increased cash and non-cash compensation expenses and increased accounting expenses for the year ended December 31, 2011 as compared to the year ended December 31, 2010. We recorded approximately $2.4 million in non-cash compensation expense for the year ended December 31, 2011 as compared to approximately $0.9 million recorded for the year ended December 31, 2010. This increase was primarily due to a change in accounting method for valuing our outstanding stock options. We awarded no new stock options during 2011. As a result of our increased oil and natural gas production, however, our general and administrative expenses decreased by 27% on a unit-of-production basis to $0.87 per Mcfe for the year ended December 31, 2011 as compared to $1.13 per Mcfe for the year ended December 31, 2010.

Net gain (loss) on asset sales and inventory impairment. We incurred a loss on asset sales and inventory impairment of approximately $154,000 for the year ended December 31, 2011, as compared to a loss of approximately $224,000 for the year ended December 31, 2010. During the year ended December 31, 2011, this loss was primarily related to the sale of pipe and other equipment and the impairment of certain equipment held in inventory, consisting primarily of drilling rig parts. During the year ended December 31, 2010, we wrote off the Boise South pipeline asset in Orange County, Texas and recognized a net loss of approximately $174,000. We also recognized an impairment of approximately $50,000 to some of our equipment held in inventory following a determination that the market value of the equipment, consisting primarily of drilling rig parts, was less than the cost.

Interest expense. For the year ended December 31, 2011, we incurred total interest expense of approximately $2.0 million. We capitalized approximately $1.3 million of our interest expense on certain qualifying projects for the year ended December 31, 2011 and expensed the remaining $683,000 to operations. During the year ended December 31, 2011, we incurred incremental net borrowings of $88.0 million under our credit agreement to finance a portion of our working capital requirements and capital expenditures. Our total outstanding borrowings at December 31, 2011 were $113.0 million, and the interest rate on these borrowings was approximately 5.3% per annum. In early January 2012, we converted this $113.0 million base rate advance to a Eurodollar-based advance, which then bore interest at 3.5% per annum. In December 2010, we borrowed $25.0 million under our credit agreement to finance a portion of our working capital requirements and capital expenditures, which remained outstanding at December 31, 2010. We incurred interest expense of approximately $3,000 for the year ended December 31, 2010.

Interest and other income. Our interest and other income decreased by approximately $50,000 to approximately $314,000, or a decrease of about 14%, for the year ended December 31, 2011 as compared to the year ended December 31, 2010. The decrease in our interest and other income was due primarily to a decrease in the average balances of our cash and cash equivalents and certificates of deposit on which we received interest income between the two periods. Our cash and cash equivalents and certificates of deposit decreased to approximately $11.6 million at December 31, 2011 from approximately $23.4 million at December 31, 2010, as we used cash and incremental borrowings to acquire additional leasehold acreage in the Eagle Ford shale play in south Texas and in the core area of the Haynesville shale play in northwest Louisiana and to fund our operated and non-operated drilling and completion activities in both areas.

Total income tax provision (benefit). We recorded a total income tax benefit of approximately $5.5 million for the year ended December 31, 2011 as compared to a total income tax provision of approximately $3.5 million for the year ended December 31, 2010. The total income tax benefit for the year ended December 31, 2011 reflected deferred income taxes almost entirely, with the exception of a state of Louisiana income tax refund of approximately $46,000 recorded during this period. During the first quarter ended March 31, 2011, the net capitalized costs of our oil and natural gas properties less related deferred income taxes exceeded the cost center ceiling by $23.0 million. As a result, we recorded an impairment charge of $35.7 million to the net capitalized costs of our oil and natural gas properties and a deferred income tax credit of $12.7 million. We recorded a total income tax provision of approximately $3.5 million for the year ended December 31, 2010. The total income tax provision for the year ended December 31, 2010 included a deferred income tax provision of approximately $4.9 million and a current income tax benefit of approximately $1.4 million, which was attributable to a refund of U.S. federal income taxes received by us. For the year ended

December 31, 2010, the deferred income tax provision was consistent with our income before income taxes, which included approximately $3.1 million in unrealized hedging gains. We had a net loss for the year ended December 31, 2011, and our effective tax rate for the year ended December 31, 2010 was 35.57%.

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

Production taxes and marketing. Our production taxes and marketing expenses increased by $0.9 million to $2.0 million, or an increase of about 84%, for the year ended December 31, 2010 as compared to the year ended December 31, 2009. The increase in our production taxes and marketing expenses was due primarily to the increase in our oil and natural gas revenues from $19.0 million to $34.0 million, or an increase of about 79%, during the respective time periods. On a unit-of-production basis, our production taxes and marketing expenses remained relatively constant year-over-year, increasing to $0.23 per Mcfe for the year ended December 31, 2010 from $0.22 per Mcfe for the year ended December 31, 2009.

Lease operating expenses. Our lease operating expenses increased by $0.6 million to $5.3 million, or an increase of about 12%, for the year ended December 31, 2010 as compared to the year ended December 31, 2009. During these respective periods, however, our oil and natural gas production increased 72% to 8.6 Bcfe from 5.0 Bcfe. As a result, our lease operating expenses per unit of production decreased by 35% to $0.61 per Mcfe for the year ended December 31, 2010 as compared to $0.94 per Mcfe for the year ended December 31, 2009. In 2010, the percentage of our production attributed to the Haynesville shale continued to increase. The unit lease operating costs associated with the Haynesville production are much less than those associated with our Cotton Valley natural gas production, primarily due to the greater salt water disposal costs associated with the Cotton Valley production.

Depletion, depreciation and amortization. Our depletion, depreciation and amortization expenses increased by $4.9 million to $15.6 million, or an increase of about 45%, for the year ended December 31, 2010 as compared to the year ended December 31, 2009. The increase in our depletion, depreciation and amortization expenses was due primarily to the increase in our oil and natural gas production to 8.6 Bcfe from 5.0 Bcfe during the respective time periods. The finding and development costs associated with our Haynesville shale reserves have been less than finding and development costs associated with our reserves producing from the Cotton Valley and other formations. As a result, our depletion, depreciation and amortization expenses on a unit-of-production basis decreased as our Haynesville production increased; these expenses decreased to $1.81 per Mcfe during the year ended December 31, 2010 from $2.15 per Mcfe during the year ended December 31, 2009.

Accretion of asset retirement obligations. Our accretion of asset retirement obligations expenses increased by approximately $18,000 to approximately $155,000, or an increase of about 13%, for the year ended December 31, 2010 as compared to the year ended December 31, 2009. The increase in our accretion of asset retirement obligations was due primarily to the addition of new wells through our drilling of operated wells and our participation in the drilling of non-operated wells, although, on the whole, this item is an insignificant component of our overall expenses.

Full-cost ceiling impairment. No impairment to the net carrying value of our oil and natural gas properties on the balance sheet resulting from the full-cost ceiling limitation was recorded at December 31, 2010. At December 31, 2009, the net capitalized costs of our oil and natural gas properties less related deferred income taxes exceeded the cost center ceiling by $16.3 million. As a result, we recorded an impairment charge of $25.2 million to the net capitalized costs of our oil and natural gas properties and a deferred income tax credit of $8.9 million. A corresponding charge of $25.2 million was also recorded to the consolidated statement of operations for the year ended December 31, 2009.

General and administrative. Our general and administrative expenses increased by $2.6 million to $9.7 million, or an increase of about 36%, for the year ended December 31, 2010 as compared to the year ended December 31, 2009. Approximately $1.0 million of this increase was due to legal and other due diligence fees resulting from an unsuccessful effort to acquire oil and natural gas producing properties and associated acreage. The remainder of the increase was due primarily to increased compensation expenses resulting from both increased salaries and retention and performance bonuses paid to certain employees during the year ended December 31, 2010. As a result of our increased oil and natural gas production, however, our general and administrative expenses decreased by 20% on a unit-of-production basis to $1.13 per Mcfe for the year ended December 31, 2010 as compared to $1.42 per Mcfe for the year ended December 31, 2009.

Net gain (loss) on asset sales and inventory impairment. During the year ended December 31, 2010, we wrote off the Boise South Pipeline asset in Orange County, Texas and recognized a net loss of approximately $174,000. We also recognized an impairment of approximately $50,000 to some of our equipment held in inventory following a determination that the market value of the equipment, consisting primarily of drilling rig parts, was less than the cost. During the year ended December 31, 2009, we recognized impairments to these drilling rig parts and tubular goods held in inventory and sold rod parts held in inventory, recognizing a net loss of approximately $379,000.

Interest expense. In December 2010, we borrowed $25.0 million under our credit agreement to finance a portion of our working capital requirements and capital expenditures. We incurred approximately $3,000 in interest expense for the year ended December 31, 2010. At December 31, 2010, the interest rate on the outstanding borrowings was approximately 1.6% per annum. We had no borrowings under the credit agreement in 2009, and as a result, we incurred no interest expense for the year ended December 31, 2009.

Interest and other income. Our interest and other income decreased by approximately $0.4 million to approximately $0.4 million, or a decrease of about 53%, for the year ended December 31, 2010 as compared to the year ended December 31, 2009. The decrease in our interest and other income was due primarily to a decrease in the average balances of our cash and cash equivalents and certificates of deposit on which we receive interest income during the year ended December 31, 2010 as compared to the year ended December 31, 2009. Our cash and cash equivalents and certificates of deposit decreased to $23.4 million at December 31, 2010 from $119.9 million at December 31, 2009, as we used cash during this period primarily to acquire additional leasehold acreage in the Eagle Ford shale play in south Texas and in the core area of the Haynesville shale play in northwest Louisiana and to fund our operated and non-operated drilling and completion activities in both areas.

Total income tax provision (benefit). We recorded a total income tax provision of approximately $3.5 million for the year ended December 31, 2010 as compared to a total income tax benefit of approximately $9.9 million recorded for the year ended December 31, 2009. For the year ended December 31, 2010, we recorded a current income tax benefit of approximately $1.4 million, which was attributable to a refund of U.S federal income taxes received by us, and we also recorded a deferred income tax provision of $4.9 million consistent with the increase in our income before income taxes for that year. For the year ended December 31, 2009, we recorded a current income tax benefit of approximately $2.3 million, primarily attributable to a net refund of U.S. federal income taxes and a refund of income taxes from the state of Louisiana. We also recorded a deferred income tax benefit of approximately $7.6 million, primarily attributable to the full-cost ceiling impairment recorded in 2009. Our effective tax rate for the year ended December 31, 2010 was 35.57%, and we had a net loss for the year ended December 31, 2009.

Liquidity and Capital Resources

Prior to the consummation of our initial public offering on February 7, 2012, our primary sources of liquidity were capital contributions from private investors, our cash flows from operations, borrowings under our credit agreement and the proceeds from a significant sale of a portion of our assets in 2008. Our primary use of capital has been, and will continue to be during 2012 and for the foreseeable future, for the acquisition, exploration and development of oil and natural gas properties. We continually evaluate potential capital sources, including equity and debt financings and additional borrowings, in order to meet our planned capital expenditures and liquidity requirements. Our future success in growing proved reserves and production will be highly dependent on our ability to access outside sources of capital. At December 31, 2011, we had cash and certificates of deposits totaling approximately $11.6 million.

In December 2011, we amended and restated our senior secured revolving credit agreement for which Comerica Bank serves as administrative agent. This amendment increased the maximum facility amount from $150.0 million to $400.0 million. Borrowings are limited to the lesser of $400.0 million or the borrowing base. At December 31, 2011, the borrowing base was $125.0 million, and we had $113.0 million of outstanding indebtedness, excluding $1.3 million in outstanding letters of credit. Subsequent to year end, we used the net proceeds from our initial public offering to repay the outstanding indebtedness under our credit agreement in full and our borrowing base was reduced to $100.0 million. On February 28, 2012, our borrowing base increased to $125.0 million pursuant to a borrowing base redetermination made by the lenders at our request. We may request additional redeterminations in accordance with our credit agreement as we increase our proved reserves. The new amended and restated credit agreement matures in December 2016. In March 2012, we borrowed $15.0 million under the credit agreement to finance a portion of our working capital requirements. At March 30, 2012, our borrowings bore interest at a variable rate of 1.75% plus a Eurodollar-based rate per annum, which equated to approximately 2.0% per annum.

We actively review acquisition opportunities on an ongoing basis. While we believe our cash and cash equivalents, together with our cash flows and future potential borrowings under our credit agreement, will be adequate to fund our capital expenditure requirements and any acquisitions of interests and acreage for 2012, funding for future acquisitions of interests and acreage or our future capital expenditure requirements for 2013 and subsequent years may require additional sources of financing, which may not be available. As a result of our anticipated increases in production and reserves, we expect to have a sufficient increase in our cash flows from operations during the year ending December 31, 2012, as compared to our cash flows from operations in prior periods, as well as a sufficient increase in the borrowing base under our credit agreement to help fund our 2012 capital expenditure budget. A majority of our anticipated increase in cash flows during the year ending December 31, 2012 is expected to come from our exploration activities on unproved properties at December 31, 2011 in the Eagle Ford shale play assuming such exploration activities are successful. These anticipated increases in our cash flows from operations are based upon current oil and natural gas prices and the hedges we currently have in place. If our exploration activities result in less cash flows than anticipated, we may seek additional sources of capital, including through borrowings under our credit agreement (assuming availability under our borrowing base). In addition to future borrowings under our credit agreement, we may also seek to raise additional funds by selling shares of our common stock or securities convertible or exercisable into our common stock (including debt securities or other preferential securities) in the public markets or otherwise. It is likely that any such sales would dilute the ownership interest of our existing shareholders. It is also possible that, to the extent we are not able to obtain additional sources, we may modify our planned capital expenditure budget for 2012 accordingly. Exploration activities are subject to a number of risks and uncertainties that could impact our ability to sufficiently increase our reserves, cash flows from operations and borrowing base under our credit agreement. See "Risk Factors — Our Exploration, Development and Exploitation Projects Require Substantial Capital Expenditures That

May Exceed Our Cash Flows From Operations and Potential Borrowings, and We May Be Unable to Obtain Needed Capital on Satisfactory Terms, Which Could Adversely Affect Our Future Growth," "Risk Factors — Drilling for and Producing Oil and Natural Gas Are Highly Speculative and Involve a High Degree of Risk, with Many Uncertainties That Could Adversely Affect Our Business" and "Risk Factors — Our Identified Drilling Locations Are Scheduled Out Over Several Years, Making Them Susceptible to Uncertainties That Could Materially Alter the Occurrence or Timing of Their Drilling."

Our cash flows for the years ended December 31, 2011, 2010 and 2009 are presented below:

	Year Ended December 31,		
	2011	**2010**	**2009**
(In thousands)			
Net cash provided by operating activities	$ 61,868	$ 27,273	$ 1,791
Net cash used in investing activities	(160,087)	(147,334)	(49,415)
Net cash provided by financing activities	87,444	36,891	1,086
Net change in cash and cash equivalents	$ (10,775)	$ (83,170)	$(46,538)

Cash Flows Provided by Operating Activities

Net cash provided by operating activities increased by $34.6 million to $61.9 million for the year ended December 31, 2011 as compared to net cash provided by operating activities of $27.3 million for the year ended December 31, 2010. Net cash provided by oil and natural gas operations increased significantly to $49.3 million for the year ended December 31, 2011 from $25.0 million for the year ended December 31, 2010. This increase reflects primarily the 79% increase in our oil and natural gas production to 15.4 Bcfe from 8.6 Bcfe between the respective periods. A portion of the increase in net cash provided by operating activities also reflects the approximate five-fold increase in our oil production for the year ended December 31, 2011 as compared to the year ended December 31, 2010, as well as a higher average oil price of $93.80 per Bbl realized during 2011 as compared to an average oil price of $76.39 per Bbl realized during 2010. Some of this increase in net cash provided by operating activities is also due to changes in our operating assets and liabilities totaling approximately $10.3 million between December 31, 2010 and December 31, 2011. Our accounts payable and accrued liabilities increased to approximately $44.3 million at December 31, 2011 from approximately $27.0 million at December 31, 2010 due to our increased operating activity in south Texas. Our accounts receivable increased to $13.2 million at December 31, 2011 as compared to $11.6 million at December 31, 2010 due primarily to the increase in our oil and natural gas production and associated revenues.

Net cash provided by operating activities increased by $25.5 million to $27.3 million for the year ended December 31, 2010 as compared to net cash provided by operating activities of $1.8 million for the year ended December 31, 2009. The increase in cash flows provided by operations reflects an increase in our production to 8.6 Bcfe from 5.0 Bcfe and an increase in the average prices we received for oil and natural gas production for the year ended December 31, 2010 as compared to the year ended December 31, 2009. Our accounts payable and accrued liabilities were approximately $26.8 million at December 31, 2010 as a result of operated horizontal wells that we were drilling and/or completing in the Haynesville and Eagle Ford shale plays and in the Cotton Valley formation during the fourth quarter of 2010. Our accounts payable and accrued liabilities were $7.3 million at December 31, 2009 as we were drilling and completing only one operated horizontal Haynesville shale well at that time.

Our operating cash flows are sensitive to a number of variables, including changes in our production and volatility of oil and natural gas prices between reporting periods. Regional and worldwide economic activity, weather, infrastructure capacity to reach markets and other variable factors significantly impact the prices of oil and natural gas. These factors are beyond our control and are difficult to predict. For additional information on the impact of changing prices on our financial position, see "Quantitative and Qualitative Disclosures About Market Risk" below. See also "Risk Factors — Our Success Is Dependent on the Prices of Oil and Natural Gas. Low Oil or Natural Gas Prices and the Substantial Volatility in These Prices May Adversely Affect Our Financial Condition and Our Ability to Meet Our Capital Expenditure Requirements and Financial Obligations."

Cash Flows Used in Investing Activities

Net cash used in investing activities increased by $12.8 million to $160.1 million for the year ended December 31, 2011 from $147.3 million for the year ended December 31, 2010. This increase in net cash used in investing activities reflected a decrease of $2.6 million in our oil and natural gas properties capital expenditures for the year ended December 31, 2011 as compared to the year ended December 31, 2010, offset almost exactly by an increase of approximately $3.0 million in expenditures for other property and equipment, which includes new pipeline infrastructure associated with our initial wells in the Eagle Ford shale. Although our capital expenditures were relatively flat year-over-year, approximately 75% of our capital expenditures were allocated to drilling and completion operations and 25% to the acquisition of additional acreage for the year ended December 31, 2011, as compared to approximately 43% allocated to drilling and completion operations and 57% allocated to acquisition of additional acreage for the year ended December 31, 2010. Our oil and natural gas properties capital expenditures for the year ended December 31, 2011 were primarily due to expenditures associated with our operated and non-operated drilling and completion activities in the Eagle Ford and Haynesville shale plays and our acreage acquisition in Karnes, DeWitt, Wilson and Gonzales Counties, Texas that we believe to be prospective for the Eagle Ford shale.

Net cash used in investing activities increased by $97.9 million to $147.3 million for the year ended December 31, 2010 from $49.4 million for the year ended December 31, 2009. This increase in net cash used in investing activities reflects primarily an increase of $104.8 million in our oil and natural gas properties capital expenditures for the year ended December 31, 2010 as compared to the year ended December 31, 2009. The increased oil and natural gas properties capital expenditures for the year ended December 31, 2010 were due to the acquisition of leasehold acreage in the Eagle Ford shale play and the acquisition of additional leasehold acreage in the Haynesville shale play, as well as expenditures associated with our operated and non-operated drilling and completion activities in both plays as compared to the year ended December 31, 2009.

Expenditures for the acquisition, exploration and development of oil and natural gas properties are the primary use of our capital resources. We anticipate investing $313.0 million in capital for acquisition, exploration and development activities in 2012 as follows:

	Amount (in millions)
Exploration and development drilling and associated infrastructure	$284.5
Leasehold acquisition	24.0
Other capital expenditures, 2-D and 3-D seismic data and recompletions of existing wells	4.5
Total	$313.0

For further information regarding our anticipated capital expenditure budget in 2012, see "Business—General."

Our 2012 capital expenditures may be adjusted as business conditions warrant. The amount, timing and allocation of capital expenditures is largely discretionary and within our control. If oil or natural gas prices decline or costs increase significantly, we could defer a significant portion of our anticipated capital expenditures until later periods to conserve cash or to focus on those projects that we believe have the highest expected returns and potential to generate near-term cash flows. We routinely monitor and adjust our capital expenditures in response to changes in prices, availability of financing, drilling, completion and acquisition costs, industry conditions, the timing of regulatory approvals, the availability of rigs, success or lack of success in our exploration and development activities, contractual obligations and other factors both within and outside our control.

Cash Flows Provided by Financing Activities

Net cash provided by financing activities was $87.4 million for the year ended December 31, 2011, as compared to net cash provided by financing activities of $36.9 million for the year ended December 31, 2010. The net cash provided by financing activities for the year ended December 31, 2011 was due almost entirely to additional borrowings of $88.0 million under our credit agreement to fund our working capital requirements as well as our acquisition of acreage prospective for the Eagle Ford shale play in Karnes, DeWitt, Wilson and Gonzales Counties, Texas. In January 2011, we sold 53,772 shares of our Class A common stock in a private placement and received net proceeds of approximately $0.6 million. During 2011, we also received proceeds from the exercise of stock options totaling approximately $0.8 million. For the year ended December 31, 2011, we also incurred cash expenditures related to preparation for our initial public offering of approximately $1.7 million.

Net cash provided by financing activities was $36.9 million for the year ended December 31, 2010 as compared to net cash provided by financing activities of $1.1 million for the year ended December 31, 2009. For the year ended December 31, 2010, the most significant financing activities occurred in the fourth quarter of 2010. During that time, we sold approximately 1.9 million shares of our Class A common stock in a private placement and received net proceeds of approximately $21.0 million, and we borrowed $25.0 million under our credit agreement. In addition, in April 2010, we repurchased 1,000,000 shares of Class A common stock from five shareholders, all advised by Wellington Management Company, for a total of $9.0 million. We also received proceeds of approximately $2.0 million from the periodic exercise of stock options during the year ended December 31, 2010. For the year ended December 31, 2009, the most significant financing activities occurred in April 2009 when we repurchased approximately 5.4 million shares of Class A common stock from Gandhara Capital, one of our largest shareholders at the time, for a total of $27.1 million and in May through September 2009 when we sold approximately 5.0 million shares of Class A common stock in a private placement and received net proceeds of approximately $28.0 million. We also received proceeds of approximately $1.3 million from the periodic exercise of stock options for the year ended December 31, 2009.

Credit Agreement

In December 2011, we amended and restated our senior secured revolving credit agreement for which Comerica Bank serves as administrative agent. Among other things, this amendment increased the size of the facility and extended the term until December 2016. MRC Energy Company is the borrower under the new amended credit agreement. Borrowings are secured by mortgages on substantially all of our oil and natural gas properties and by the equity interests of all of MRC Energy Company's wholly owned subsidiaries, which are also guarantors. In addition, all obligations under the credit agreement are guaranteed by Matador Resources Company, the parent corporation. Various commodity hedging agreements with one of the lenders under the credit agreement (or an affiliate thereof) are also secured by the collateral and guaranteed by the subsidiaries of MRC Energy Company.

The amount of the borrowings under our amended and restated credit agreement is limited to the lesser of $400.0 million or the borrowing base, which is determined semi-annually as of May 1 and November 1 by the lenders based primarily on the estimated value of our existing and future acquired oil and gas reserves, but also on external factors, such as the lenders' lending policies and the lenders' estimates of future oil and natural gas prices, over which we have no control. At December 31, 2011, the borrowing base was $125.0 million and we had $113.0 million in outstanding borrowings under the credit agreement. In January 2012, we borrowed an additional $10.0 million to finance a portion of our working capital requirements, bringing the then total outstanding indebtedness under the credit agreement to $123.0 million. Following the completion of our initial public offering, we used a portion of the net proceeds to repay the $123.0 million outstanding under our credit agreement in February 2012, at which time the borrowing base was reduced to $100.0 million. On February 28, 2012, the borrowing base was increased to $125.0 million pursuant to a special borrowing base redetermination made at our request. This borrowing base increase was determined by our lenders based upon, among other items, the increase in our oil and natural gas reserves at December 31, 2011.

In March 2012, we borrowed $15.0 million under the credit agreement to finance a portion of our working capital requirements and capital expenditures. At March 30, 2012, we had $15.0 million in borrowings outstanding under the credit agreement, approximately $1.3 million in outstanding letters of credit issued pursuant to the credit agreement and approximately $108.7 million available for additional borrowings. At March 30, 2012, our outstanding borrowings bore interest at approximately 2.0% per annum. We expect to access future borrowings under our credit agreement to fund a portion of our 2012 capital expenditure requirements in excess of amounts available from our cash flows. During 2012, we also intend to seek additional redeterminations of our borrowing base as a result of, among other items, any increases to our proved oil and natural gas reserves during the year.

Both we and the lenders may each request an unscheduled redetermination of the borrowing base twice at any time during the first year of the credit agreement and once between scheduled redetermination dates thereafter. As noted above, we requested one such unscheduled redetermination in February 2012. In the event of a borrowing base increase, we are required to pay a fee to the lenders equal to a percentage of the amount of the increase, which will be determined based on market conditions at the time of the borrowing base increase. If the borrowing base were to be less than the outstanding borrowings under the credit agreement at any time, we would be required to provide additional collateral satisfactory in nature and value to the lenders to increase the borrowing base to an amount sufficient to cover such excess or to repay the deficit in equal installments over a period of six months.

If we borrow funds as a base rate loan, such borrowings will bear interest at a rate equal to the higher of (i) the weighted average of rates used in overnight federal funds transactions with members of the Federal Reserve System plus 1.0% or (ii) the prime rate for Comerica Bank then in effect or (iii) a daily adjusted LIBOR rate plus 1.0% plus, in each case, an amount from 0.375% to 1.75% of such outstanding loan depending on the level of borrowings under the agreement. If we borrow funds as a Eurodollar loan, such borrowings will bear interest at a rate equal to (i) the quotient obtained by dividing (A) the interest rate appearing on Page BBAM of the Bloomberg Financial Markets Information Service by (B) a percentage equal to 100% minus the maximum rate during such interest calculation period at which Comerica Bank is required to maintain reserves on Eurocurrency Liabilities (as defined in Regulation D of the Board of Governors of the Federal Reserve System), plus (ii) an amount from 1.375% to 2.75% of such outstanding loan depending on the level of borrowings under the agreement. The interest period for Eurodollar borrowings may be one, two, three or six months as designated by us. A facility fee of 0.375% to 0.50%, depending on the amounts borrowed, is also paid quarterly in arrears. We include the facility fee in our interest rate calculations and related disclosures.

Key financial covenants under the credit agreement require us to maintain (1) a minimum current ratio, which is defined as consolidated total current assets plus the unused availability under the credit agreement divided by consolidated total current liabilities, of 1.0 for all reporting periods beginning March 31, 2012, and (2) a debt to EBITDA ratio, which is defined as total debt outstanding divided by a rolling four quarter EBITDA calculation, of 4.0 to 1.0 or less, beginning December 31, 2011.

Subject to certain exceptions, our credit agreement contains various covenants that limit our, along with our subsidiaries', ability to take certain actions, including, but not limited to, the following:

- incur indebtedness or grant liens on any of our assets;
- enter into commodity hedging agreements;
- declare or pay dividends, distributions or redemptions;
- merge or consolidate;
- make any loans or investments;
- engage in transactions with affiliates; and
- engage in certain asset dispositions, including a sale of all or substantially all of our assets.

If an event of default exists under the credit agreement, the lenders will be able to accelerate the maturity of the borrowings and exercise other rights and remedies. Events of default include, but are not limited to, the following events:

- failure to pay any principal or interest on the notes or any reimbursement obligation under any letter of credit when due or any fees or other amount within certain grace periods;
- failure to perform or otherwise comply with the covenants and obligations in the credit agreement or other loan documents, subject, in certain instances, to certain grace periods;
- bankruptcy or insolvency events involving us or our subsidiaries; and
- a change of control, as defined in the credit agreement.

In December 2010, the credit agreement was amended to increase the borrowing base to $55.0 million. At December 31, 2010, we had $25.0 million of outstanding borrowings and $50,000 in letters of credit issued pursuant to the credit agreement. At December 31, 2010, all borrowings under the credit agreement were Eurodollar loans, and the interest rate on the outstanding borrowings was approximately 1.6% per annum. We had an additional $325,000 in letters of credit secured by certificates of deposit at Comerica Bank at December 31, 2010.

At December 31, 2011, the borrowing base available for revolving borrowings was $125.0 million, and we had $113.0 million in revolving borrowings outstanding under the credit agreement, approximately $1.3 million in outstanding letters of credit issued pursuant to the credit agreement and approximately $10.7 million available for additional borrowings. At December 31, 2011, our outstanding revolving borrowings bore interest at the rate of approximately 5.3% per annum. Prior to the December 2011 amendment, the outstanding revolving borrowings under our credit agreement were scheduled to mature in March 2013.

In addition to our revolving borrowings under our credit agreement, in May 2011, we borrowed $25.0 million in a term loan pursuant to the credit agreement to help finance the acquisition of the Eagle Ford shale acreage from Orca ICI Development, JV in Karnes, DeWitt, Wilson and Gonzales Counties, Texas. The term loan was due and payable on December 31, 2011, and there was no penalty for prepayment. The term loan was refinanced by borrowings under the amended and restated credit agreement in December 2011.

We believe that we were in compliance with the terms of our credit agreement and with all our bank covenants at December 31, 2011. We obtained a written extension until May 1, 2012 to comply with a covenant under the credit agreement requiring the submission of certain year-end 2011 operating information for the lenders' use on or before March 1, 2012.

Off-Balance Sheet Arrangements

At December 31, 2011, we did not have any off-balance sheet arrangements.

Obligations and Commitments

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

	Payments Due by Period				
	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
(in thousands)					
Contractual Obligations:					
Revolving credit borrowings and term loan, including letters of credit(1)	$114,300	$26,300	$ –	$88,000	$ –
Office lease	6,243	287	1,150	1,193	3,613
Non-operated drilling commitments(2)	5,100	5,100	–	–	–
Drilling rig contracts(3)	2,667	2,667	–	–	–
Employee bonuses	1,240	–	1,240	–	–
Asset retirement obligations	4,270	263	413	993	2,601
Total contractual cash obligations	$133,820	$34,617	$2,803	$90,186	$6,214

(1) At December 31, 2011, we had $113.0 million in revolving borrowings outstanding under our amended and restated credit agreement and approximately $1.3 million in outstanding letters of credit issued pursuant to the credit agreement. A total of $25.0 million of these borrowings was scheduled to mature on December 31, 2012, and the remaining borrowings were scheduled to mature in December 2016. These amounts do not include estimated interest on the obligations, because our revolving borrowings had short-term interest periods, and we are unable to determine what our borrowing costs may be in future periods.

(2) At December 31, 2011, we had outstanding commitments to participate in the drilling and completion of various non-operated wells in the Haynesville shale. Our working interests in these wells are small, and most of these wells were in progress at December 31, 2011. If all of these wells are drilled and completed, we will have minimum outstanding aggregate commitments for our participation in these wells of approximately $5.1 million at December 31, 2011, which we expect to incur within the next 12 months.

(3) At December 31, 2011, we had entered into two drilling rig contracts to explore and develop our Eagle Ford acreage in south Texas. The two rigs began drilling on our acreage in September 2011 and October 2011, respectively. Both contracts are for a term of six months. Should we elect to terminate one or both contracts and if the drilling contractor were unable to secure work for one or both rigs or if the drilling contractor were unable to secure work for one or both rigs at the same daily rates being charged to us prior to the end of their respective contract terms, we would incur termination obligations. Our maximum outstanding aggregate termination obligations under these contracts were approximately $2.7 million at December 31, 2011.

General Outlook and Trends

For the year ended December 31, 2011, oil prices ranged from a high of approximately $114.00 per Bbl in April to a low of approximately $76.00 per Bbl in October, based upon the NYMEX West Texas Intermediate oil futures contract price for the earliest delivery date. Generally, oil prices remained above $90.00 per Bbl for much of the year. We realized an average oil price of $93.80 per Bbl for our oil production for the year ended December 31, 2011 as compared to $76.39 per Bbl for the year ended December 31, 2010. At March 30, 2012, the NYMEX West Texas Intermediate oil futures contract for the earliest delivery date closed at $103.02 per Bbl as compared to $104.27 per Bbl at March 30, 2011.

For the year ended December 31, 2011, natural gas prices ranged from a high of approximately $4.80 per MMBtu in January and June to a low of approximately $3.00 per MMBtu in December, based upon the NYMEX Henry Hub natural gas futures contract price for the earliest delivery date. Natural gas prices remained relatively flat during the first six months of 2011 trading between approximately $3.80 per MMBtu and $4.80 per MMBtu. Beginning in mid-July 2011, natural gas prices began a steady decline of more than 50% to their lowest levels in many years. We realized a natural gas price of $3.62 per Mcf ($4.11 per Mcf including realized gains from natural gas derivatives) for our natural gas production for the year ended December 31, 2011 as compared to $3.75 per Mcf ($4.38 per Mcf including realized gains from natural gas derivatives) for the year ended December 31, 2010. At March 30, 2012, the NYMEX Henry Hub natural gas futures contract for the earliest delivery date closed at $2.13 per MMBtu as compared to $4.36 per MMBtu at March 30, 2011.

The prices we receive for oil and natural gas heavily influence our revenue, profitability, cash flow available for capital expenditures, access to capital and future rate of growth. Oil and natural gas are commodities, and therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil and natural gas have been volatile and these markets will likely continue to be volatile in the future. Declines in oil or natural gas prices not only reduce our revenue, but could also reduce the amount of oil and natural gas we can produce economically. From time to time, we use derivative financial instruments to mitigate our exposure to commodity price risk associated with oil and natural gas prices. Even so, decisions as to whether and what production volumes to hedge are difficult and depend on market conditions and our forecast of future production and oil and natural gas prices, and we may not always employ the optimal hedging strategy. Should oil or natural gas prices decrease to economically unattractive levels and remain there for an extended period of time, we may elect to delay some of our exploration and development plans for our prospects, or to cease exploration or development activities on certain prospects due to the anticipated unfavorable economics from such activities, each of which would have a material adverse effect on our business, financial condition, results of operations and reserves. This, in turn, may affect the liquidity that can be accessed through our borrowing base under our credit agreement and through the capital markets.

Like other oil and natural gas producing companies, our properties are subject to natural production declines. By their nature, our wells in the Eagle Ford shale and the Haynesville shale will experience rapid initial production declines. We attempt to overcome these production declines by drilling to develop and identify additional reserves, by exploring for new sources of reserves and, at times, by acquisitions. During times of severe oil and natural gas price declines, however, we may find it necessary to reduce capital expenditures and curtail drilling operations in order to preserve liquidity. A material reduction in capital expenditures and drilling activities could materially impact our production volumes, revenues, reserves and cash flows.

We must focus our efforts on increasing oil and gas reserves and production while controlling costs at a level that is appropriate for long-term operations. Our ability to find and develop sufficient quantities of oil and natural gas reserves at economical costs is critical to our long-term success. Future finding and development costs are subject to changes in the costs of acquiring, drilling and completing our prospects.

Critical accounting policies and estimates

We have outlined below certain accounting policies that are of particular importance to the presentation of our financial condition and results of operations and require the application of significant judgment or estimates by our management.

The preparation of financial statements requires us to make other estimates and assumptions that affect the reported amounts of certain assets, liabilities, revenues and expenses during each reporting period. We believe that our estimates and assumptions are reasonable and reliable, and believe that the ultimate actual results will not differ significantly from those reported; however, such estimates and assumptions are subject to a number of risks and uncertainties, and such risk and uncertainties could cause the actual results to differ materially from our estimates.

Property and Equipment

We use the full-cost method of accounting for our investments in oil and natural gas properties. Under this method of accounting, all costs associated with the acquisition, exploration and development of oil and natural gas properties and reserves, including unproved and unevaluated property costs, are capitalized as incurred and accumulated in a single cost center representing our activities, which are undertaken exclusively in the United States. Such costs include lease acquisition costs, geological and geophysical expenditures, lease rentals on undeveloped properties, costs of drilling both productive and non-productive wells, capitalized interest on qualifying projects and general and administrative expenses directly related to exploration and development activities, but do not include any costs related to production, selling or general corporate administrative activities.

The net capitalized costs of oil and natural gas properties are limited to the lower of unamortized costs less related deferred income taxes or the cost center ceiling, with any excess above the cost center ceiling charged to operations as a full-cost ceiling impairment. The cost center ceiling is defined as the sum of (a) the present value discounted at 10 percent of future net revenues of proved oil and natural gas reserves, plus (b) unproved and unevaluated property costs not being amortized, plus (c) the lower of cost or estimated fair value of unproved and unevaluated properties included in the costs being amortized, if any, less (d) income tax effects related to the properties involved. Future net revenues from proved non-producing and proved undeveloped reserves are reduced by the estimated costs of developing these reserves. The fair value of our derivative instruments is not included in the ceiling test computation as we do not designate these instruments as hedge instruments for accounting purposes.

The estimated present value of after-tax future net cash flows from proved oil and natural gas reserves is highly dependent on the commodity prices used in these estimates. These estimates are determined in accordance with guidelines established by the SEC for estimating and reporting oil and natural gas reserves. Under these guidelines, oil and natural gas reserves are estimated using then-current operating and economic conditions, with no provision for price and cost escalations in future periods except by contractual arrangements.

Capitalized costs of oil and natural gas properties are amortized using the unit-of-production method based upon production and estimates of proved reserves quantities. Unproved and unevaluated property costs are excluded from the amortization base used to determine depletion. Unproved and unevaluated properties are assessed for impairment on a periodic basis based upon changes in operating or economic conditions. This assessment includes consideration of the following factors, among others: the assignment of proved reserves, geological and geophysical evaluations, intent to drill, remaining lease term and drilling activity and results. Upon impairment, the costs of the unproved and unevaluated properties are immediately included in the amortization base. Exploratory dry holes are included in the amortization base immediately upon the determination that the well is not productive.

Sales of oil and natural gas properties are accounted for as adjustments to net capitalized costs with no gain or loss recognized, unless such adjustments would significantly alter the relationship between net capitalized costs and proved reserves of oil and natural gas. All costs related to production activities and maintenance and repairs are expensed as incurred. Significant workovers that increase the properties' reserves are capitalized.

Other property and equipment are stated at cost. Computer equipment, furniture, software and other equipment are depreciated over their useful life (five to seven years) using the straight-line method. Support equipment and facilities include the pipelines and salt water disposal systems owned by Longwood Gathering and Disposal Systems, LP and are depreciated over a 30-year useful life using the straight-line, mid-month convention method. Leasehold improvements are depreciated over the lesser of their useful life or the term of the lease.

Derivative Financial Instruments

From time to time, we use derivative financial instruments to hedge our exposure to commodity price risk associated with oil and natural gas prices. These instruments consist of put and call options in the form of costless (or zero-cost) collars. A costless collar provides us with downside price protection through the purchase of a put option which is financed through the sale of a call option. Because the call proceeds are used to offset the cost of the put option, this arrangement is initially "costless" to us. Our derivative financial instruments are recorded on the balance sheet as either an asset or a liability measured at fair value. We have elected not to apply hedge accounting for our existing derivative financial instruments, and as a result, we recognize the change in derivative fair value between reporting periods currently in our consolidated statement of operations. The fair value of our derivative financial instruments is determined using purchase and sale information available for similarly traded securities. Realized gains and realized losses from the settlement of derivative financial instruments and unrealized gains and unrealized losses from valuation changes in the remaining unsettled derivative financial instruments are reported under "Revenues" in our consolidated statement of operations.

Revenue Recognition

We follow the sales method of accounting for our oil and natural gas revenue, whereby we recognize revenue, net of royalties, on all oil or natural gas sold to purchasers regardless of whether the sales are proportionate to our ownership in the property. Under this method, revenue is recognized at the time the oil and natural gas are produced and sold, and we accrue for revenue earned but not yet received.

Stock-based Compensation

Non-qualified stock option expense is typically recognized in our consolidated statement of operations on the date of grant. Incentive stock options vest over four years, and the associated compensation expense is recognized on a straight-line basis over the vesting period. We account for stock based compensation in accordance with ASC 718. At December 31, 2011, we used the fair value method to measure and recognize the liability associated with our outstanding stock options. As our shares were not publicly traded prior to February 2, 2012, we estimate the future volatility of our stock using the historical volatility of the common stock of a group of companies we consider to be a representative peer group. Management believes that these average historical volatility rates are currently the best available indicator of future volatility.

We have adopted the "simplified method" as outlined in Staff Accounting Bulletin Topic 14 for estimating the expected term of awards. The risk free interest rate is the rate for constant yield U.S. Treasury securities with a term to maturity that is consistent with the expected term of the award.

Assumptions are reviewed each time there is a new grant and may be impacted by actual fluctuations in our stock price, movements in market interest rates and options terms. The use of different assumptions produces a different fair value for the options granted or outstanding, when accounted for as a liability award, and impacts the amount of stock compensation expense recognized in our consolidated statement of operations. The fair value of restricted stock awards are recognized based upon the fair value of our stock on the date of the grant.

Prior to November 22, 2010, all of our outstanding stock options were classified as equity instruments, with all stock-based compensation expense measured on the date of grant and recognized over the vesting period, if any. On November 22, 2010, we changed our method of accounting for outstanding stock options, reclassifying all outstanding stock options from equity to liability instruments. This change was made as a result of purchasing shares from certain of our employees to assist them in the exercise of outstanding options of our Class A common stock. As a result, at December 31, 2010, we measured and recognized the fair value of the liability associated with our outstanding stock options using the intrinsic value method.

Income Taxes

We account for income taxes using the asset and liability approach for financial accounting and reporting. We evaluate the probability of realizing the future benefits of our deferred tax assets and provide a valuation allowance for the portion of any deferred tax assets where the likelihood of realizing an income tax benefit in the future does not meet the more likely than not criteria for recognition.

We account for uncertainty in income taxes by recognizing the financial statement benefit of a tax position only after determining that the relevant tax authority would more likely than not sustain the position following an audit. For tax positions meeting the more likely than not threshold, the amount recognized in the financial statements is the benefit that has a greater than 50 percent likelihood of being realized upon ultimate settlement with the relevant tax authority.

We have evaluated all tax positions for which the statute of limitations remained open, and we believe that the material positions taken would more likely than not be sustained by examination. Therefore, at December 31, 2011, we had not established any reserves for, nor recorded any unrecognized tax benefits related to, uncertain tax positions. When necessary, we include interest assessed by taxing authorities in "Interest expense" and penalties related to income taxes in "Other expense" on our consolidated statement of operations.

Oil and Natural Gas Reserves Quantities and Standardized Measure of Future Net Revenue

Our engineers and technical staff prepare our estimates of oil and natural gas reserves and associated future net revenues. While the SEC has recently adopted rules which allow us to disclose proved, probable and possible reserves, we have elected to present only proved reserves in this report. The SEC's revised rules define proved reserves as the 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. Our engineers and technical staff must make many subjective assumptions based on their professional judgment in developing reserves estimates. Reserves estimates are updated at least annually and consider recent production levels and other technical information about each well. Estimating oil and natural gas reserves is complex and is not exact because of the numerous uncertainties inherent in the process. The process relies on interpretations of available geological, geophysical, petrophysical, engineering and production data. The extent, quality and reliability of both the data and the associated interpretations can vary. The process also requires certain economic assumptions, including, but not limited to, oil and natural gas prices, revenues, development expenditures, operating expenses, capital expenditures and taxes. Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas will most likely vary from our estimates. Accordingly, reserves estimates are generally different from the quantities of oil and natural gas that are ultimately recovered. Any significant variance could materially and adversely affect our future reserves estimates, financial position, results of operations and cash flows. We cannot predict the amounts or timing of future reserves revisions. If such revisions are significant, they could significantly affect future amortization of capitalized costs and result in impairment of assets that may be material.

Recent Accounting Pronouncements

Balance Sheet. In December 2011, the FASB issued Accounting Standards Update, or ASU, 2011-11, *Balance Sheet.* The requirements amend the disclosure requirements to offsetting in Accounting Standards Codification, or ASC, 210-20-50. The amendments require enhanced disclosures by requiring improved information about financial instruments and derivative instruments that are either (1) offset in accordance with either ASC 210-20-45 or ASC 815-10-45 or (2) subject to an enforceable master netting agreement or similar agreement, irrespective of whether they are offset in accordance with either ASC 210-20-45 or ASC 815-10-45. The adoption of ASU 2011-11 is not expected to have a material effect on our consolidated financial statements, but may require certain additional disclosures. The amendments in ASU 2011-11 are to be applied for annual reporting periods beginning on or after January 1, 2013 and are to be applied retrospectively for all reporting periods presented.

Fair Value. In May 2011, the FASB issued ASU 2011-04, *Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS.* ASU 2011-04 amends ASC 820, *Fair Value Measurements*, providing a consistent definition and measurement of fair value, as well as similar disclosure requirements between GAAP and International Financial Reporting Standards. ASU 2011-04 changes certain fair value measurement principles, clarifies the application of existing fair value measurements and expands the ASC 820 disclosure requirements, particularly for Level 3 fair value measurements. The adoption of ASU 2011-04 is not expected to have a material impact on our consolidated financial statements, but may require certain additional disclosures. The amendments in ASU 2011-04 are to be applied prospectively. For public entities, the amendments are effective during interim and annual periods beginning after December 15, 2011.

In January 2010, the FASB issued authoritative guidance to update certain disclosure requirements and added two new disclosure requirements related to fair value measurements. The guidance requires a gross presentation of activities within the Level 3 roll forward and adds a new requirement to disclose details of significant transfers in and out of Level 1 and 2 measurements and the reasons for the transfers. The new disclosures are required for all companies that are required to provide disclosures about recurring and non-recurring fair value measurements, and are effective the first interim or annual reporting period beginning after December 15, 2009, except for the gross presentation of the Level 3 roll forward information, which is required for annual reporting periods beginning after December 15, 2010 and for interim reporting periods within those years. We adopted the first portion of this guidance beginning January 1, 2010 and the remaining portions beginning January 1, 2011. The adoption of this new guidance did not have a significant impact on our financial position, results of operations or cash flows.

Oil and Natural Gas Reserves Reporting Requirements. In January 2009, the SEC issued *The Modernization of Oil and Gas Reporting, Final Rule.* In January 2010, the Financial Accounting Standards Board, or FASB, amended Topic 932, *Extractive Activities — Oil and Gas* to align with this rule. The changes are designed to modernize and update the oil and natural gas disclosure requirements to align them with current practices and changes in technology. The new rules made a number of important changes including the following: (i) expanded the definition of oil and natural gas producing activities to include the extraction of saleable hydrocarbons from oil sands, shale, coalbeds or other nonrenewable natural resources, (ii) amended the required price for estimating economic quantities for year-end reserves reporting to be the unweighted, arithmetic average of the first-day-of-the-month price for each month within the previous 12-month period, rather than the year-end price and (iii) permitted proved reserves to be claimed beyond those development spacing areas that are immediately adjacent to developed spacing areas if it can be established with reasonable certainty that these reserves are economically producible. At December 31, 2009, we adopted the provisions of this new rule, and we have applied this new guidance for the reserves estimates shown for December 31, 2011, 2010 and 2009 included herein.

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

We are exposed to a variety of market risks including commodity price risk, interest rate risk and counterparty and customer risk. We address these risks through a program of risk management including the use of derivative financial instruments.

Commodity price exposure. We are exposed to market risk as the prices of oil and natural gas fluctuate as a result of changes in supply and demand and other factors. To partially reduce price risk caused by these market fluctuations, we have entered into derivative financial instruments in the past and expect to enter into derivative financial instruments in the future to cover a significant portion of our future production.

We use costless (or zero-cost) collars to manage risks related to changes in oil and natural gas prices. A costless collar provides us with downside price protection through the purchase of a put option which is financed through the sale of a call option. Because the call option proceeds are used to offset the cost of the put option, this arrangement is initially "costless" to us.

We record all derivative financial instruments at fair value. The fair value of our derivative financial instruments is determined using purchase and sale information available for similarly traded securities. Comerica Bank is the single counterparty for all of our derivative instruments. We have evaluated the credit standing of Comerica Bank in determining the fair value of our derivative financial instruments.

At December 31, 2011, 2010 and 2009, we used costless collar options to reduce the volatility of natural gas prices on a significant portion of our future expected natural gas production. For each calculation period, the specified price for determining the realized gain or loss to us pursuant to any of these transactions is the settlement price for the NYMEX Henry Hub natural gas futures contract for the delivery month corresponding to the calculation period's calendar month for the last day of that contract period. When the settlement price is below the price floor established by these collars, we receive from Comerica Bank, as counterparty, an amount equal to the difference between the settlement price and the price floor multiplied by the contract natural gas volume. When the settlement price is above the price ceiling established by these collars, we pay to Comerica, as counterparty, an amount equal to the difference between the settlement price and the price ceiling multiplied by the contract natural gas volume.

The following is a summary of our open natural gas costless collar contracts at February 29, 2012.

Commodity	Calculation Period	Notional Quantity	Price Floor	Price Ceiling	Fair Value of Asset
		(MMBtu/month)	($/MMBtu)	($/MMBtu)	(thousands)
Natural Gas	07/01/2011 — 12/31/2012	300,000	4.50	5.60	$ 4,948
Natural Gas	07/01/2011 — 07/31/2013	150,000	4.50	5.75	3,584
Natural Gas	01/01/2012 — 12/31/2012	150,000	4.25	6.17	2,120
Total					$10,652

All of our existing natural gas derivative contracts will expire at varying times during 2012 and 2013.

Between November 2011 and February 2012, we entered into various costless collar transactions to mitigate our exposure to oil price volatility for the first time. For each calculation period, the specified price for determining the realized gain or loss to us pursuant to any of these oil hedging transactions is the arithmetic average of the settlement prices for the NYMEX West Texas Intermediate oil futures contract for the first nearby month corresponding to the calculation period's calendar month. When the settlement price is below the price floor established by these collars, we receive from Comerica Bank, as counterparty, an amount equal to the difference between the settlement price and the price floor multiplied by the contract oil volume hedged. When the settlement price is above the price ceiling established by these collars, we pay Comerica Bank, as counterparty, an amount equal to the difference between the settlement price and the price ceiling multiplied by the contract oil volume hedged.

The following table is a summary of our open oil costless collar contracts at February 29, 2012.

Commodity	Calculation Period	Notional Quantity	Price Floor	Price Ceiling	Fair Value of Liability
		(Bbls/month)	($/Bbl)	($/Bbl)	(thousands)
Oil	12/01/2011 — 12/31/2012	20,000	90.00	104.20	$ (1,475)
Oil	01/01/2012 — 12/31/2012	10,000	90.00	108.00	(526)
Oil	01/01/2012 — 12/31/2012	10,000	90.00	109.50	(455)
Oil	02/01/2012 — 06/30/2012	20,000	90.00	113.75	(150)
Oil	04/01/2012 — 12/31/2012	20,000	90.00	111.00	(762)
Oil	04/01/2012 — 03/31/2013	20,000	90.00	110.00	(1,117)
Oil	07/01/2012 — 12/31/2012	20,000	90.00	111.90	(509)
Oil	07/01/2012 — 12/31/2012	20,000	95.00	116.00	(165)
Oil	01/01/2013 — 12/31/2013	20,000	85.00	102.25	(2,056)
Oil	01/01/2013 — 12/31/2013	20,000	90.00	115.00	(330)
Oil	01/01/2013 — 12/31/2013	20,000	85.00	110.40	(1,102)
Oil	01/01/2013 — 12/31/2013	20,000	85.00	108.80	(1,231)
Oil	01/01/2013 — 06/30/2014	8,000	90.00	114.00	(121)
Oil	01/01/2013 — 06/30/2014	12,000	90.00	115.50	(71)
Total					$(10,070)

All of our existing oil derivative contracts will expire at varying times during 2012, 2013 and 2014.

Effect of Recent Derivatives Legislation

On July 21, 2010, President Obama signed into law the Dodd-Frank Act, which is intended to modernize and protect the integrity of the U.S. financial system. The Dodd-Frank Act, among other things, sets forth the new framework for regulating certain derivative products including the commodity hedges of the type used by us, but many aspects of this law are subject to further rulemaking and will take effect over several years. As a result, it is difficult to anticipate the overall impact of the Dodd-Frank Act on our ability or willingness to continue entering into and maintaining such commodity hedges and the terms thereof. Based upon the limited assessments we are able to make with respect to the Dodd-Frank Act, there is the possibility that the Dodd-Frank Act could have a substantial and adverse impact on our ability to enter into and maintain these commodity hedges. In particular, the Dodd-Frank Act could result in the implementation of position limits and additional regulatory requirements on our derivative arrangements, which could include new margin, reporting and clearing requirements. In addition, this legislation could have a substantial impact on our counterparties and may increase the cost of our derivative arrangements in the future. See "Risk Factors — The Derivatives Legislation Adopted by Congress Could Have an Adverse Impact on Our Ability to Hedge Risks Associated with Our Business."

Interest rate risk. We do not use interest rate derivatives to alter interest rate exposure in an attempt to reduce interest rate expense on existing debt since we borrowed under our existing credit agreement for the first time in December 2010 and had $113.0 million in revolving borrowings outstanding at December 31, 2011 under our amended and restated credit agreement at an interest rate of approximately 5.3% per annum. In addition to our revolving borrowings, in May 2011, we borrowed $25.0 million in a term loan pursuant to the credit agreement. The term loan was refinanced through revolving borrowings in December 2011 under our amended and restated credit agreement. At March 30, 2012, we had $15.0 million in revolving debt outstanding under our credit agreement at an interest rate of 2.0% per annum. If we incur additional indebtedness in the future and at higher interest rates, we may use interest rate derivatives. Interest rate derivatives would be used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio.

Counterparty and customer credit risk. Joint interest receivables arise from billing entities which own partial interest in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we wish to drill. We have limited ability to control participation in our wells. We are also subject to credit risk due to concentration of our oil and natural gas receivables with several significant customers. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial position, results of operations and cash flows. In addition, our oil and natural gas derivative arrangements expose us to credit risk in the event of nonperformance by counterparties.

While we do not require our customers to post collateral and we do not have a formal process in place to evaluate and assess the credit standing of our significant customers for oil and natural gas receivables and the counterparties on our derivative instruments, we do evaluate the credit standing of such counterparties as we deem appropriate under the circumstances. This evaluation may include reviewing a counterparty's credit rating, latest financial information and, in the case of a customer with which we have receivables, its historical payment record, the financial ability of the customer's parent company to make payment if the customer cannot and undertaking the due diligence necessary to determine credit terms and credit limits. The counterparty on our derivative instruments currently in place is Comerica Bank and we are likely to enter into any future derivative instruments with Comerica Bank or one of the other lenders party to the credit agreement.

Impact of Inflation. Inflation in the United States has been relatively low in recent years and did not have a material impact on our results of operations for the years ended December 31, 2011, 2010 and 2009. Although the impact of inflation has been generally insignificant in recent years, it is still a factor in the United States economy and we tend to specifically experience inflationary pressure on the cost of oilfield services and equipment with increases in oil and natural gas prices and with increases in drilling activity in our areas of operations, including the Eagle Ford shale and Haynesville shale plays. See "Business — General." See also "Risk Factors — The Unavailability or High Cost of Drilling Rigs, Completion Equipment and Services, Supplies and Personnel, Including Hydraulic Fracturing Equipment and Personnel, Could Adversely Affect Our Ability to Establish and Execute Exploration and Development Plans within Budget and on a Timely Basis, Which Could Have a Material Adverse Effect on Our Financial Condition, Results of Operations and Cash Flows."

Item 8. Financial Statements and Supplementary Data.

Our financial statements appear at the end of this Form 10-K. Please see the index to the financial statements in Item 15.

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

Not applicable.

Item 9A. Controls and Procedures.

This Annual Report does not include a report of management's assessment regarding internal control over financial reporting or an attestation report of the company's registered public accounting firm due to a transition period established by rules of the SEC for newly public companies.

Prior to the completion of our initial public offering, we maintained limited accounting personnel to perform our accounting processes and limited supervisory resources with which to address our internal control over financial reporting. In connection with our audit for the year ended December 31, 2011, our independent registered public accountants identified and communicated a material weakness related to accounting for stock compensation expense. A material weakness is a control deficiency, or a combination of control deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of our annual and interim financial statements will not be prevented or detected and corrected on a timely basis.

We have begun the process of evaluating our internal control over financial reporting and expect to put into place new accounting processes and control procedures to address the weakness described above, including the hiring of outside consultants to review significant or complex accounting issues and calculations, the implementation of a more formalized closing process, the formation of a disclosure committee and the hiring of additional personnel. We cannot predict the outcome of this process at this time. We will be required to make our first assessment of our internal control over financial reporting at December 31, 2012.

We became a public company on February 1, 2012 in connection with the completion of our initial public offering. Prior to that date, we were a private company and were not required to file or submit reports under the Securities Exchange Act of 1934, as amended (the "Exchange Act") and maintained disclosure controls and procedures in accordance with being a private company. As of the end of the period covered by this report, an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e)) under the Exchange Act was performed under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer. Based upon this evaluation, as of the end of the period covered by this report, our Chief Executive Officer and our Chief Financial Officer concluded that our disclosure controls and procedures were not effective because we were not yet a public company and, therefore, had not yet established formal disclosure controls and procedures and because the material weakness described above relating to our internal control over financial reporting was identified.

Item 9B. Other Information.

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance.

The information required in response to this Item 10 is incorporated herein by reference to our definitive proxy statement to be filed with the SEC pursuant to Regulation 14A promulgated under the Exchange Act, not later than 120 days after the end of the fiscal year covered by this Annual Report.

Item 11. Executive Compensation.

The information required in response to this Item 11 is incorporated herein by reference to our definitive proxy statement to be filed with the SEC pursuant to Regulation 14A promulgated under the Exchange Act not later than 120 days after the end of the fiscal year covered by this Annual Report.

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

Certain information regarding securities authorized for issuance under our equity compensation plans is included under the caption "Equity Compensation Plan Information" in Part II, Item 5, above, of this Annual Report and is incorporated by reference herein. Other information required in response to this Item 12 is incorporated herein by reference to our definitive proxy statement to be filed with the SEC pursuant to Regulation 14A promulgated under the Exchange Act not later than 120 days after the end of the fiscal year covered by this Annual Report.

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

The information required in response to this Item 13 is incorporated herein by reference to our definitive proxy statement to be filed with the SEC pursuant to Regulation 14A promulgated under the Exchange Act not later than 120 days after the end of the fiscal year covered by this Annual Report.

Item 14. Principal Accounting Fees and Services.

The information required in response to this Item 14 is incorporated herein by reference to our definitive proxy statement to be filed with the SEC pursuant to Regulation 14A promulgated under the Exchange Act not later than 120 days after the end of the fiscal year covered by this Annual Report.

PART IV

Item 15. Exhibits and Financial Statement Schedules.

The following documents are filed as part of this report:

1. Index to Consolidated Financial Statements, 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 Shareholders' Equity for the years ended December 31, 2011, 2010 and 2009 and Consolidated Statements of Cash Flows for the years ended December 31, 2011, 2010 and 2009.

2. *Exhibits*: The exhibits required to be filed by this Item 15 are set forth in the Exhibit Index accompanying this report.

EXHIBIT INDEX

Exhibit Number	Description
1.1	Underwriting Agreement (incorporated by reference to Exhibit 1.1 to the Current Report on Form 8-K filed on February 7, 2012).
2.1	Agreement and Plan of Merger, by and among Matador Resources Company (now known as MRC Energy Company), Matador Holdco, Inc. (now known as Matador Resources Company) and Matador Merger Co., dated August 8, 2011 (incorporated by reference to Exhibit 2.1 to our Registration Statement on Form S-1 filed on August 12, 2011).
3.1	Certificate of Formation of Matador Resources Company (formerly known as Matador Holdco, Inc.) (incorporated by reference to Exhibit 3.1 to our Registration Statement on Form S-1 filed on August 12, 2011).
3.2	Certificate of Amendment to Certificate of Formation of Matador Resources Company (formerly known as Matador Holdco, Inc.) (incorporated by reference to Exhibit 3.2 to our Registration Statement on Form S-1 filed on August 12, 2011).
3.3	Certificate of Amendment to Certificate of Formation of Matador Resources Company (formerly known as Matador Holdco, Inc.) (incorporated by reference to Exhibit 3.3 to our Registration Statement on Form S-1 filed on August 12, 2011).
3.4	Certificate of Merger between Matador Resources Company (now known as MRC Energy Company) and Matador Merger Co. (incorporated by reference to Exhibit 3.4 to our Registration Statement on Form S-1 filed on August 12, 2011).
3.5	Bylaws of Matador Resources Company (formerly known as Matador Holdco, Inc.) (incorporated by reference to Exhibit 3.5 to our Registration Statement on Form S-1 filed on August 12, 2011).
3.6	Amendment to the Bylaws of Matador Resources Company (formerly known as Matador Holdco, Inc.) (incorporated by reference to Exhibit 3.6 to our Registration Statement on Form S-1 filed on August 12, 2011).
3.7	Amended and Restated Certificate of Formation of Matador Resources Company (formerly known as Matador Holdco, Inc.) (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed on February 13, 2012).
3.8	Amended and Restated Bylaws of Matador Resources Company (formerly known as Matador Holdco, Inc.) (incorporated by reference to Exhibit 3.2 to the Current Report on Form 8-K filed on February 13, 2012).
4.1	Form of Common Stock Certificate (incorporated by reference to Exhibit 4.1 to Amendment No. 4 to our Registration Statement on Form S-1 filed on January 19, 2012).
10.1	Amended and Restated Credit Agreement, dated at May 19, 2011, by and among Matador Resources Company (now known as MRC Energy Company), Comerica Bank and the Lenders signatory thereto (incorporated by reference to Exhibit 10.1 to Amendment No. 1 to our Registration Statement on Form S-1 filed on November 14, 2011).
10.2	Pledge and Security Agreement, by and between Matador Resources Company (formerly known as Matador Holdco, Inc.) and Comerica Bank, dated at August 9, 2011 (incorporated by reference to Exhibit 10.2 to Amendment No. 1 to our Registration Statement on Form S-1 filed on November 14, 2011).
10.3†	Employment Agreement between Matador Resources Company (formerly known as Matador Holdco, Inc.) and Joseph Wm. Foran (incorporated by reference to Exhibit 10.3 to Amendment No. 1 to our Registration Statement on Form S-1 filed on November 14, 2011).

10.4† Employment Agreement between Matador Resources Company (formerly known as Matador Holdco, Inc.) and David E. Lancaster (incorporated by reference to Exhibit 10.4 to Amendment No. 1 to our Registration Statement on Form S-1 filed on November 14, 2011).

10.5† Employment Agreement between Matador Resources Company (formerly known as Matador Holdco, Inc.) and Matthew Hairford (incorporated by reference to Exhibit 10.5 to Amendment No. 1 to our Registration Statement on Form S-1 filed on November 14, 2011).

10.6† Employment Agreement between Matador Resources Company (formerly known as Matador Holdco, Inc.) and Bradley M. Robinson (incorporated by reference to Exhibit 10.6 to Amendment No. 1 to our Registration Statement on Form S-1 filed on November 14, 2011).

10.7† Independent Contractor Agreement between Matador Resources Company (formerly known as Matador Holdco, Inc.) and David F. Nicklin (incorporated by reference to Exhibit 10.7 to Amendment No. 1 to our Registration Statement on Form S-1 filed on November 14, 2011).

10.8† First Amendment to the Employment Agreement between Matador Resources Company (formerly known as Matador Holdco, Inc.) and Joseph Wm. Foran (incorporated by reference to Exhibit 10.8 to Amendment No. 1 to our Registration Statement on Form S-1 filed on November 14, 2011).

10.9† First Amendment to the Employment Agreement between Matador Resources Company (formerly known as Matador Holdco, Inc.) and David E. Lancaster (incorporated by reference to Exhibit 10.9 to Amendment No. 1 to our Registration Statement on Form S-1 filed on November 14, 2011).

10.10† First Amendment to the Employment Agreement between Matador Resources Company (formerly known as Matador Holdco, Inc.) and Matthew Hairford (incorporated by reference to Exhibit 10.10 to Amendment No. 1 to our Registration Statement on Form S-1 filed on November 14, 2011).

10.11† First Amendment to the Employment Agreement between Matador Resources Company (formerly known as Matador Holdco, Inc.) and Bradley M. Robinson (incorporated by reference to Exhibit 10.11 to Amendment No. 1 to our Registration Statement on Form S-1 filed on November 14, 2011).

10.12† Second Amendment to the Employment Agreement between Matador Resources Company (formerly known as Matador Holdco, Inc.) and Joseph Wm. Foran (incorporated by reference to Exhibit 10.12 to Amendment No. 2 to our Registration Statement on Form S-1 filed on December 30, 2011).

10.13† Second Amendment to the Employment Agreement between Matador Resources Company (formerly known as Matador Holdco, Inc.) and David E. Lancaster (incorporated by reference to Exhibit 10.13 to Amendment No. 2 to our Registration Statement on Form S-1 filed on December 30, 2011).

10.14† Second Amendment to the Employment Agreement between Matador Resources Company (formerly known as Matador Holdco, Inc.) and Matthew Hairford (incorporated by reference to Exhibit 10.14 to Amendment No. 2 to our Registration Statement on Form S-1 filed on December 30, 2011).

10.15† Second Amendment to the Employment Agreement between Matador Resources Company (formerly known as Matador Holdco, Inc.) and Bradley M. Robinson (incorporated by reference to Exhibit 10.15 to Amendment No. 2 to our Registration Statement on Form S-1 filed on December 30, 2011).

10.16† First Amendment to the Independent Contractor Agreement between Matador Resources Company (formerly known as Matador Holdco, Inc.) and David F. Nicklin (incorporated by reference to Exhibit 10.16 to Amendment No. 2 to our Registration Statement on Form S-1 filed on December 30, 2011).

10.17† 2012 Long-Term Incentive Plan of Matador Resources Company (formerly known as Matador Holdco, Inc.) (incorporated by reference to Exhibit 10.17 to Amendment No. 2 to our Registration Statement on Form S-1 filed on December 30, 2011).

10.18† Matador Resources Company (formerly known as Matador Holdco, Inc.) Annual Incentive Plan for Management and Key Employees (incorporated by reference to Exhibit 10.18 to Amendment No. 2 to our Registration Statement on Form S-1 filed on December 30, 2011).

10.19† Matador Resources Company (now known as MRC Energy Company) 2003 Stock and Incentive Plan, dated October 23, 2003 (incorporated by reference to Exhibit 10.15 to Amendment No. 1 to our Registration Statement on Form S-1 filed on November 14, 2011).

10.20† First Amendment to Matador Resources Company (now known as MRC Energy Company) 2003 Stock and Incentive Plan, dated January 29, 2004 (incorporated by reference to Exhibit 10.16 to Amendment No. 1 to our Registration Statement on Form S-1 filed on November 14, 2011).

10.21† Second Amendment to Matador Resources Company (now known as MRC Energy Company) 2003 Stock and Incentive Plan, dated February 3, 2005 incorporated by reference to Exhibit 10.17 to Amendment No. 1 to our Registration Statement on Form S-1 filed on November 14, 2011).

10.22† Third Amendment to Matador Resources Company (now known as MRC Energy Company) 2003 Stock and Incentive Plan, dated February 1, 2006 (incorporated by reference to Exhibit 10.18 to Amendment No. 1 to our Registration Statement on Form S-1 filed on November 14, 2011).

10.23† Fourth Amendment to Matador Resources Company (now known as MRC Energy Company) 2003 Stock and Incentive Plan, dated May 1, 2006 (incorporated by reference to Exhibit 10.19 to Amendment No. 1 to our Registration Statement on Form S-1 filed on November 14, 2011).

10.24† Fifth Amendment to Matador Resources Company (now known as MRC Energy Company) 2003 Stock and Incentive Plan, dated February 13, 2008 (incorporated by reference to Exhibit 10.20 to Amendment No. 1 to our Registration Statement on Form S-1 filed on November 14, 2011).

10.25† Sixth Amendment to Matador Resources Company (now known as MRC Energy Company) 2003 Stock and Incentive Plan, dated August 5, 2008 (incorporated by reference to Exhibit 10.21 to Amendment No. 1 to our Registration Statement on Form S-1 filed on November 14, 2011).

10.26† Seventh Amendment to Matador Resources Company (now known as MRC Energy Company) 2003 Stock and Incentive Plan, dated December 12, 2011 (incorporated by reference to Exhibit 10.26 to Amendment No. 2 to our Registration Statement on Form S-1 filed on December 30, 2011).

10.27† Form of Indemnification Agreement between Matador Resources Company (formerly known as Matador Holdco, Inc.) and each of the directors and executive officers thereof (incorporated by reference to Exhibit 10.22 to Amendment No. 1 to our Registration Statement on Form S-1 filed on November 14, 2011).

10.28 Participation Agreement, by and among MRC Rockies Company, Matador Resources Company (now known as MRC Energy Company), Matador Production Company, Roxanna Rocky Mountains, LLC, Roxanna Oil, Inc., Alliance Capital Real Estate, Inc. and AllianceBernstein L.P., dated at May 14, 2010 (incorporated by reference to Exhibit 10.23 to Amendment No. 1 to our Registration Statement on Form S-1 filed on November 14, 2011).

10.29 Assignment, Bill of Sale and Conveyance, by and among Winn Exploration Co., Inc., Pinion Exploration, LLP, McDay Oil & Gas, Inc. and Matador Resources Company (now known as MRC Energy Company), dated effective at December 1, 2010 (incorporated by reference to Exhibit 10.24 to Amendment No. 1 to our Registration Statement on Form S-1 filed on November 14, 2011).

10.30 Purchase, Sale and Participation Agreement, by and between Matador Resources Company (now known as MRC Energy Company) and Orca ICI Development, JV, dated at May 16, 2011 (incorporated by reference to Exhibit 10.25 to Amendment No. 1 to our Registration Statement on Form S-1 filed on November 14, 2011).

10.31 Second Amended and Restated Credit Agreement dated as of December 30, 2011, by and among MRC Energy Company, Comerica Bank and the Lenders party thereto from time to time (incorporated by reference to Exhibit 10.31 to Amendment No. 3 to our Registration Statement on Form S-1 filed on January 13, 2012).

10.32	Amended and Restated Pledge and Security Agreement, by and among MRC Energy Company, Longwood Gathering and Disposal Systems GP, Inc. and Comerica Bank, dated as of December 30, 2011 (incorporated by reference to Exhibit 10.32 to Amendment No. 3 to our Registration Statement on Form S-1 filed on January 13, 2012).
10.33	Amended, Restated and Consolidated Unconditional Guaranty, by and among MRC Permian Company, MRC Rockies Company, Matador Production Company, Longwood Gathering and Disposal Systems GP, Inc., Longwood Gathering and Disposal Systems, LP, Matador Resources Company (formerly known as Matador Holdco, Inc.) and Comerica Bank, dated at December 30, 2011 (incorporated by reference to Exhibit 10.33 to Amendment No. 3 to our Registration Statement on Form S-1 filed on January 13, 2012).
10.34†	Employment Agreement between Matador Resources Company (formerly known as Matador Holdco, Inc.) and Wade Massad (incorporated by reference to Exhibit 10.34 to Amendment No. 3 to our Registration Statement on Form S-1 filed on January 13, 2012).
10.35†	Nonqualified Stock Option Agreement, dated February 1, 2012, by and between Matador Resources Company and Wade Massad (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on February 7, 2012).
10.36†	Form of Non-Qualified Stock Option Agreement granted pursuant to the Matador Resources Company (now known as MRC Energy Company) 2003 Stock and Incentive Plan (filed herewith).
10.37†	Form of Incentive Stock Option Agreement granted pursuant to the Matador Resources Company (now known as MRC Energy Company) 2003 Stock and Incentive Plan (filed herewith).
10.38†	Form of Nonqualified Stock Option Agreement relating to the Matador Resources Company (formerly known as Matador Holdco, Inc.) 2012 Long-Term Incentive Plan (filed herewith).
10.39†	Form of Restricted Stock Unit Award Agreement relating to the Matador Resources Company (formerly known as Matador Holdco, Inc.) 2012 Long-Term Incentive Plan (filed herewith).
10.40†	Form of Restricted Stock Award Agreement relating to the Matador Resources Company (formerly known as Matador Holdco, Inc.) 2012 Long-Term Incentive Plan (filed herewith).
21.1	List of Subsidiaries of Matador Resources Company (formerly known as Matador Holdco, Inc.) (incorporated by reference to Exhibit 21.1 to our Registration Statement on Form S-1 filed on August 12, 2011).
23.1	Consent of Netherland, Sewell & Associates, Inc. (filed herewith).
31.1	Certification of Principal Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).
31.2	Certification of Principal Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).
32.1	Certification of Principal Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (filed herewith).
32.2	Certification of Principal Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (filed herewith).
99.1	Audit report of Netherland, Sewell & Associates, Inc. (filed herewith).

† Indicates a management contract or compensatory plan or arrangement.

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.

MATADOR RESOURCES COMPANY

April 2, 2012

By: /s/ Joseph Wm. Foran
Joseph Wm. Foran
Chairman, President and Chief 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/ Joseph Wm. Foran Joseph Wm. Foran	Chairman, President and Chief Executive Officer (Principal Executive Officer)	April 2, 2012
/s/ David E. Lancaster David E. Lancaster	Executive Vice President, Chief Operating Officer and Chief Financial Officer (Principal Financial Officer)	April 2, 2012
/s/ Kathryn L. Wayne Kathryn L. Wayne	Controller and Treasurer (Principal Accounting Officer)	April 2, 2012
/s/ Charles L. Gummer Charles L. Gummer	Director	April 2, 2012
/s/ Stephen A. Holditch Stephen A. Holditch	Director	April 2, 2012
/s/ David M. Laney David M. Laney	Director	April 2, 2012
/s/ Gregory E. Mitchell Gregory E. Mitchell	Director	April 2, 2012
/s/ Steven W. Ohnimus Steven W. Ohnimus	Director	April 2, 2012
/s/ Michael C. Ryan Michael C. Ryan	Director	April 2, 2012
/s/ Margaret B. Shannon Margaret B. Shannon	Director	April 2, 2012

Exhibit 31.1

CERTIFICATION

I, Joseph Wm. Foran, certify that:

1. I have reviewed this annual report on Form 10-K of Matador Resources Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b. Paragraph omitted pursuant to Exchange Act Rule 13a-14(a);

c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

April 2, 2012

/s/ Joseph Wm. Foran

Joseph Wm. Foran
Chairman, President and Chief Executive Officer
(Principal Executive Officer)

Exhibit 31.2

CERTIFICATION

I, David E. Lancaster, certify that:

1. I have reviewed this annual report on Form 10-K of Matador Resources Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b. Paragraph omitted pursuant to Exchange Act Rule 13a-14(a);

c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

April 2, 2012

/s/ David E. Lancaster

David E. Lancaster
Executive Vice President, Chief Operating Officer
and Chief Financial Officer
(Principal Financial Officer)

Exhibit 32.1

**CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the annual report of Matador Resources Company (the "Company") on Form 10-K for the year ended December 31, 2011 as filed with the Securities and Exchange Commission on the date hereof (the "Form 10-K"), I, Joseph Wm. Foran, Chairman, President and Chief Executive Officer of the Company, hereby certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

(1) The Form 10-K fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Form 10-K fairly presents, in all material respects, the financial condition and results of operations of the Company.

April 2, 2012

/s/ Joseph Wm. Foran

Joseph Wm. Foran
Chairman, President and Chief Executive Officer
(Principal Executive Officer)

Exhibit 32.2

**CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the annual report of Matador Resources Company (the "Company") on Form 10-K for the year ended December 31, 2011 as filed with the Securities and Exchange Commission on the date hereof (the "Form 10-K"), I, David E. Lancaster, Executive Vice President, Chief Operating Officer and Chief Financial Officer of the Company, hereby certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

(1) The Form 10-K fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Form 10-K fairly presents, in all material respects, the financial condition and results of operations of the Company.

April 2, 2012

/s/ David E. Lancaster

David E. Lancaster
Executive Vice President, Chief Operating Officer
and Chief Financial Officer
(Principal Financial Officer)

GLOSSARY OF OIL AND NATURAL GAS TERMS

The following is a description of the meanings of some of the oil and natural gas industry terms used in this report.

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

Bcf. One billion cubic feet.

Bcfe. One billion cubic feet of natural gas equivalents, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

BOE. Barrels of oil equivalent, determined using the ratio of one Bbl of crude oil, condensate or natural gas liquids, to six Mcf of natural gas.

Btu or British thermal unit. The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Completion. The operations required to establish production of oil or natural gas from a wellbore, usually involving perforations, stimulation and/or installation of permanent equipment in the well, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

Condensate. Liquid hydrocarbons associated with the production of a primarily natural gas reserve.

Conventional resources. Natural gas or oil that is produced by a well drilled into a geologic formation in which the reservoir and fluid characteristics permit the natural gas or oil to readily flow to the wellbore.

Coring. The act of taking a core. A core is a solid column of rock, usually from two to four inches in diameter, taken as a sample of an underground formation. It is common practice to take cores from wells in the process of being drilled. A core bit is attached to the end of the drill pipe. The core bit then cuts a column of rock from the formation being penetrated. The core is then removed and tested for evidence of oil or natural gas, and its characteristics (porosity, permeability, etc.) are determined.

Developed acreage. The number of acres that are allocated or assignable to productive wells.

Development well. A well drilled into a proved 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 exceed production-related expenses and taxes.

Exploratory well. A well drilled to find and produce oil or natural gas reserves not classified as proved, 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.

Farmin or farmout. An agreement under which the owner of a working interest in an oil or natural gas lease assigns the working interest or a portion of the working interest to another party who desires to drill on the leased acreage. Generally, the assignee is required to drill one or more wells in order to earn its interest in the acreage. The assignor usually retains a royalty or reversionary interest in the lease. The interest received by an assignee is a "farmin" while the interest transferred by the assignor is a "farmout."

FERC. Federal Energy Regulatory Commission.

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Fracture stimulation technology. The technique of improving a well's production or injection rates by pumping a mixture of fluids into the formation and rupturing the rock, creating an artificial channel. As part of this technique, sand or other material may also be injected into the formation to prop the channel open, so that fluids or gases may more easily flow from the formation, through the fracture channel and into the wellbore. This technique may also be referred to as hydraulic fracturing.

Gross acres or gross wells. The total acres or wells in which a working interest is owned.

Held by production. An oil and natural gas property under lease in which the lease continues to be in force after the primary term of the lease in accordance with its terms as a result of production from the property.

Horizontal drilling or well. A drilling operation in which a portion of the well is drilled horizontally within a productive or potentially productive formation. This operation typically yields a horizontal well that has the ability to produce higher volumes than a vertical well drilled in the same formation. A horizontal well is designed to replace multiple vertical wells, resulting in lower capital expenditures for draining like acreage and limiting surface disruption.

Liquids. Liquids, or natural gas liquids, are marketable liquid products including ethane, propane, butane and pentane resulting from the further processing of liquefiable hydrocarbons separated from raw natural gas by a gas processing facility.

MBbl. One thousand barrels of crude oil or other liquid hydrocarbons.

Mcf. One thousand cubic feet of natural gas.

Mcfe. One thousand cubic feet of natural gas equivalents, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

MMBtu. One million British thermal units.

MMcf. One million cubic feet of natural gas.

MMcf/d. MMcf per day.

MMcfe. One million cubic feet of natural gas equivalents, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

MMcfe/day. MMcfe per day.

Net acres or net wells. The sum of the fractional working interest owned in gross acres or wells.

Net revenue interest. The interest that defines the percentage of revenue that an owner of a well receives from the sale of oil, gas and/or natural gas liquids that are produced from the well.

NYMEX. New York Mercantile Exchange.

Overriding royalty interest. A fractional interest in the gross production of oil and natural gas under a lease, in addition to the usual royalties paid to the lessor, free of any expense for exploration, drilling, development, operating, marketing and other costs incident to the production and sale of oil and natural gas produced from the lease. It is an interest carved out of the lessee's working interest, as distinguished from the lessor's reserved royalty interest.

Permeability. A reference to the ability of oil and/or natural gas to flow through a reservoir.

Petrophysical analysis. The interpretation of well log measurements, obtained from a string of electronic tools inserted into the borehole, and from core measurements, in which rock samples are retrieved from the subsurface, then combining these measurements with other relevant geological and geophysical information to describe the reservoir rock properties.

Play. A set of known or postulated oil and/or natural gas accumulations sharing similar geologic, geographic and temporal properties, such as source rock, migration pathways, timing, trapping mechanism and hydrocarbon type.

Possible reserves. Additional reserves that are less certain to be recognized than probable reserves.

Probable reserves. Additional reserves that are less certain to be recognized than proved reserves but which, in sum with proved reserves, are as likely as not to be recovered.

Producing well, production well or productive well. A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the well's production exceed production-related expenses and taxes.

Properties. Natural gas and oil wells, production and related equipment and facilities and natural gas, oil or other mineral fee, leasehold and related interests.

Prospect. A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is considered to have potential for the discovery of commercial hydrocarbons.

Proved developed non-producing. Hydrocarbons in a potentially producing horizon penetrated by a wellbore, the production of which has been postponed pending installation of surface equipment or gathering facilities, or pending the production of hydrocarbons from another formation penetrated by the wellbore. The hydrocarbons are classified as proved but non-producing reserves.

Proved developed reserves. Proved reserves that can be expected to be recovered through existing wells and facilities and by existing operating methods.

Proved reserves. Reserves of oil and natural gas that have been proved to a high degree of certainty by analysis of the producing history of a reservoir and/or by volumetric analysis of adequate geological and engineering data.

Proved undeveloped reserves. Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

Recompletion. Completing in the same wellbore to reach a new reservoir after production from the original reservoir has been abandoned.

Repeatability. The potential ability to drill multiple wells within a prospect or trend.

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

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

2-D seismic. The method by which a cross-section of the earth's subsurface is created through the interpretation of reflecting seismic data collected along a single source profile.

3-D seismic. The method by which a three-dimensional image of the earth's subsurface is created through the interpretation of reflection seismic data collected over a surface grid. 3-D seismic surveys allow for a more detailed understanding of the subsurface than do 2-D seismic surveys and contribute significantly to field appraisal, exploitation and production.

Spud. The act of beginning to drill an oil or natural gas well.

Trend. A region of oil and/or natural gas production, the geographic limits of which have not been fully defined, having geological characteristics that have been ascertained through supporting geological, geophysical or other data to contain the potential for oil and/or natural gas reserves in a particular formation or series of formations.

Unconventional resource play. A set of known or postulated oil and or gas resources or reserves warranting further exploration which are extracted from (i) low-permeability sandstone and shale formations and (ii) coalbed methane. These plays require the application of advanced technology to extract the oil and natural gas resources.

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas, regardless of whether such acreage contains proved reserves. Undeveloped acreage is usually considered to be all acreage that is not allocated or assignable to productive wells.

Unproved and unevaluated properties. Properties where no drilling or other actions have been undertaken that permit such property to be classified as proved.

Vertical well. A hole drilled vertically into the earth from which oil, natural gas or water flows or is pumped.

Visualization. An exploration technique in which the size and shape of subsurface features are mapped and analyzed based upon information derived from well logs, seismic data and other well information.

Volumetric reserve analysis. A technique used to estimate the amount of recoverable oil and natural gas. It involves calculating the volume of reservoir rock and adjusting that volume for the rock porosity, hydrocarbon saturation, formation volume factor and recovery factor.

Wellbore. The hole made by a well.

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production.

Matador Resources Company and Subsidiaries

CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2011, 2010 and 2009

Contents

Report of Independent Registered Public Accounting Firm

Board of Directors and Shareholders
Matador Resources Company

We have audited the accompanying consolidated balance sheets of Matador Resources Company (a Texas corporation) and subsidiaries (collectively, the "Company") as of December 31, 2011 and 2010, and the related consolidated statements of operations, shareholders' 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. The Company is not required to have, nor were we engaged to perform an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, 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 Matador Resources Company 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.

As discussed in Note 2 to the financial statements, the Company adopted new oil and gas reserves estimation and disclosure requirements as of December 31, 2009. In addition, as discussed in Note 8, the Company changed its method of valuation of stock options for recording stock option expense in 2011.

/s/ GRANT THORNTON LLP
Dallas, Texas
April 2, 2012

Matador Resources Company and Subsidiaries

CONSOLIDATED BALANCE SHEETS

	December 31, 2011	December 31, 2010
ASSETS		
Current assets		
Cash and cash equivalents	$ 10,284,180	$ 21,059,519
Certificates of deposit	1,335,000	2,349,313
Accounts receivable		
Oil and natural gas revenues	9,237,322	6,514,122
Joint interest billings	2,488,070	2,042,999
Other	1,446,113	3,091,372
Derivative instruments	8,988,767	4,144,411
Lease and well equipment inventory	1,343,416	1,423,197
Prepaid expenses	1,153,214	1,802,807
Total current assets	36,276,082	42,427,740
Property and equipment, at cost		
Oil and natural gas properties, full-cost method		
Evaluated	423,944,476	255,408,993
Unproved and unevaluated	162,597,985	172,451,449
Other property and equipment	18,764,038	14,035,010
Less accumulated depletion, depreciation and amortization	(205,441,724)	(138,014,986)
Net property and equipment	399,864,775	303,880,466
Other assets		
Derivative instruments	847,267	–
Deferred income taxes	1,593,331	–
Other assets	887,061	73,551
Total other assets	3,327,659	73,551
Total assets	$ 439,468,516	$ 346,381,757
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable	$ 18,841,295	$ 12,166,938
Accrued liabilities	25,438,893	14,789,712
Royalties payable	1,855,296	982,270
Borrowings under Credit Agreement	25,000,000	–
Derivative instruments	171,252	–
Advances from joint interest owners	–	722,843
Deferred income taxes	3,023,760	1,473,619
Dividends payable — Class B	68,713	68,713
Other current liabilities	176,868	23,577
Total current liabilities	74,576,077	30,227,672
Long-term liabilities		
Borrowings under Credit Agreement	88,000,000	25,000,000
Asset retirement obligations	3,935,084	3,563,851
Derivative instruments	382,848	–
Deferred income taxes	–	5,432,638
Other long-term liabilities	1,059,314	280,453
Total long-term liabilities	93,377,246	34,276,942
Commitments and contingencies (Note 12)		
Shareholders' equity		
Common stock — Class A, $0.01 par value, 80,000,000 shares authorized; 42,916,668 and 42,749,820 shares issued; and 41,737,493 and 41,570,645 shares outstanding, respectively	429,166	427,498
Common stock — Class B, $0.01 par value, 2,000,000 shares authorized; 1,030,700 shares issued and outstanding	10,307	10,307
Additional paid-in capital	263,561,890	263,341,642
Retained earnings	18,278,652	28,862,518
Treasury stock, at cost, 1,179,175 shares	(10,764,822)	(10,764,822)
Total shareholders' equity	271,515,193	281,877,143
Total liabilities and shareholders' equity	$ 439,468,516	$ 346,381,757

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

Matador Resources Company and Subsidiaries

CONSOLIDATED STATEMENTS OF OPERATIONS

	For the years ended December 31,		
	2011	2010	2009
Revenues			
Oil and natural gas revenues	$ 66,999,826	$34,041,607	$ 19,038,514
Realized gain on derivatives	7,106,260	5,299,380	7,625,120
Unrealized gain (loss) on derivatives	5,137,522	3,138,726	(2,374,638)
Total revenues	79,243,608	42,479,713	24,288,996
Expenses			
Production taxes and marketing	6,277,860	1,981,550	1,077,145
Lease operating	7,244,339	5,284,362	4,725,022
Depletion, depreciation and amortization	31,753,640	15,596,470	10,742,873
Accretion of asset retirement obligations	208,547	154,756	137,347
Full-cost ceiling impairment	35,673,098	–	25,243,738
General and administrative	13,394,390	9,701,850	7,115,118
Total expenses	94,551,874	32,718,988	49,041,243
Operating (loss) income	(15,308,266)	9,760,725	(24,752,247)
Other (expense) income			
Net loss on asset sales and inventory impairment	(153,533)	(223,690)	(379,316)
Interest expense	(682,754)	(3,235)	–
Interest and other income	314,136	364,338	781,072
Total other (expense) income	(522,151)	137,413	401,756
(Loss) income before income taxes	(15,830,417)	9,898,138	(24,350,491)
Income tax (benefit) provision			
Current	(45,576)	(1,410,608)	(2,324,338)
Deferred	(5,475,828)	4,931,783	(7,600,811)
Total income tax (benefit) provision	(5,521,404)	3,521,175	(9,925,149)
Net (loss) income	$(10,309,013)	$ 6,376,963	$(14,425,342)
Earnings (loss) per common share			
Basic			
Class A	$ (0.25)	$ 0.15	$ (0.37)
Class B	$ 0.02	$ 0.42	$ (0.10)
Diluted			
Class A	$ (0.25)	$ 0.15	$ (0.37)
Class B	$ 0.02	$ 0.42	$ (0.10)
Weighted average common shares outstanding			
Basic			
Class A	41,686,807	40,006,787	39,092,567
Class B	1,030,700	1,030,700	1,030,700
Total	42,717,507	41,037,487	40,123,267
Diluted			
Class A	41,686,807	40,102,927	39,092,567
Class B	1,030,700	1,030,700	1,030,700
Total	42,717,507	41,133,627	40,123,267

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

Matador Resources Company and Subsidiaries
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
For the years ended December 31, 2011, 2010 and 2009

	Common stock				Additional paid-in capital	Retained earnings (deficit)	Treasury stock		Total
	Class A		Class B						
	Shares	Amount	Shares	Amount			Shares	Amount	
Balance at January 1, 2009	40,548,037	$405,480	1,030,700	$10,307	$238,413,969	$ 38,526,701	(39,873)	$ (351,545)	$277,004,912
Issuance of Class A common stock	4,974,194	49,742	–	–	28,201,626	–	–	–	28,251,368
Cost to issue equity	–	–	–	–	(92,549)	–	–	–	(92,549)
Repurchase and retirement of Class A common stock	(5,422,713)	(54,227)	–	–	(26,686,133)	(373,205)	–	–	(27,113,565)
Stock options granted	–	–	–	–	592,962	–	–	–	592,962
Stock options exercised	343,500	3,435	–	–	1,278,065	–	–	–	1,281,500
Restricted stock vested	–	–	–	–	33,750	–	–	–	33,750
Class B dividends declared	–	–	–	–	–	(274,853)	–	–	(274,853)
Current period net loss	–	–	–	–	–	(14,425,342)	–	–	(14,425,342)
Issuance of treasury stock	–	–	–	–	(78,178)	(692,893)	652,126	4,787,678	4,016,607
Purchase of treasury stock	–	–	–	–	–	–	(679,923)	(4,953,400)	(4,953,400)
Balance at December 31, 2009	40,443,018	404,430	1,030,700	10,307	241,663,512	22,760,408	(67,670)	(517,267)	264,321,390
Issuance of Class A common stock	1,879,427	18,794	–	–	20,632,903	–	–	–	20,651,697
Cost to issue equity	–	–	–	–	(531,152)	–	–	–	(531,152)
Issuance of Class A common stock to Board members and advisors	20,000	200	–	–	197,800	–	–	–	198,000
Stock options granted	–	–	–	–	414,610	–	–	–	414,610
Stock options exercised	392,375	3,924	–	–	1,974,451	–	–	–	1,978,375
Stock options modified	–	–	–	–	(1,086,271)	–	–	–	(1,086,271)
Restricted stock issued	15,000	150	–	–	(150)	–	–	–	–
Restricted stock vested	–	–	–	–	73,689	–	–	–	73,689
Class B dividends declared	–	–	–	–	–	(274,853)	–	–	(274,853)
Current period net income	–	–	–	–	–	6,376,963	–	–	6,376,963
Issuance of treasury stock	–	–	–	–	2,250	–	6,000	45,000	47,250
Purchase of treasury stock	–	–	–	–	–	–	(1,117,505)	(10,292,555)	(10,292,555)
Balance at December 31, 2010	42,749,820	427,498	1,030,700	10,307	263,341,642	28,862,518	(1,179,175)	(10,764,822)	281,877,143
Issuance of Class A common stock	53,772	538	–	–	590,954	–	–	–	591,492
Cost to issue equity	–	–	–	–	(1,667,013)	–	–	–	(1,667,013)
Issuance of Class A common stock to Board members and advisors	20,075	201	–	–	230,199	–	–	–	230,400
Stock options exercised	93,001	929	–	–	1,022,082	–	–	–	1,023,011
Restricted stock vested	–	–	–	–	44,026	–	–	–	44,026
Class B dividends declared	–	–	–	–	–	(274,853)	–	–	(274,853)
Current period net loss	–	–	–	–	–	(10,309,013)	–	–	(10,309,013)
Balance at December 31, 2011	42,916,668	$429,166	1,030,700	$10,307	$263,561,890	$ 18,278,652	(1,179,175)	$(10,764,822)	$271,515,193

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

Matador Resources Company and Subsidiaries
CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the years ended December 31, 2011	2010	2009
Operating activities			
Net (loss) income	$ (10,309,013)	$ 6,376,963	$ (14,425,342)
Adjustments to reconcile net (loss) income to net cash provided by operating activities			
Unrealized (gain) loss on derivatives	(5,137,522)	(3,138,726)	2,374,638
Depletion, depreciation and amortization	31,753,640	15,596,470	10,742,873
Accretion of asset retirement obligations	208,547	154,756	137,347
Full-cost ceiling impairment	35,673,098	–	25,243,738
Stock option and grant expense	2,361,799	824,048	622,337
Restricted stock grants	44,026	73,689	33,750
Deferred income tax (benefit) provision	(5,475,828)	4,931,783	(7,600,811)
Loss on asset sales and inventory impairment	153,533	223,690	379,316
Changes in operating assets and liabilities			
Accounts receivable	(1,523,011)	(385,671)	408,710
Lease and well equipment inventory	22,412	(8,078)	(799,844)
Prepaid expenses	649,593	(579,964)	(186,371)
Other assets	(813,510)	33,165	33,165
Accounts payable, accrued liabilities and other current liabilities	13,497,251	2,487,643	(15,463,066)
Royalties payable	873,026	309,005	35,763
Advances from joint interest owners	(722,843)	272,843	450,000
State income tax payable	–	–	(48,000)
Other long-term liabilities	613,108	101,423	(147,155)
Net cash provided by operating activities	61,868,306	27,273,039	1,791,048
Investing activities			
Proceeds from sale of oil and natural gas properties	–	–	28,732
Oil and natural gas properties capital expenditures	(156,431,123)	(159,050,066)	(54,243,838)
Expenditures for other property and equipment	(4,670,981)	(1,609,882)	(306,642)
Purchases of certificates of deposit	(4,298,000)	(3,739,000)	(15,500,424)
Sales of certificates of deposit	5,312,313	17,065,033	20,607,012
Net cash used in investing activities	(160,087,791)	(147,333,915)	(49,415,160)
Financing activities			
Repayments of borrowings under Credit Agreement	(103,000,000)	–	–
Borrowings under Credit Agreement	191,000,000	25,000,000	–
Proceeds from issuance of common stock	591,492	20,651,697	28,251,368
Cost to issue equity	(1,709,502)	(171,978)	(92,549)
Proceeds from stock options exercised	837,009	1,978,375	1,281,500
Payment of dividends — Class B	(274,853)	(274,853)	(274,853)
Repurchase and retirement of Class A common stock	–	–	(27,113,565)
Issuance of treasury stock	–	–	3,987,231
Purchase of treasury stock	–	(10,292,555)	(4,953,400)
Net cash provided by financing activities	87,444,146	36,890,686	1,085,732
Decrease in cash and cash equivalents	(10,775,339)	(83,170,190)	(46,538,380)
Cash and cash equivalents at beginning of year	21,059,519	104,229,709	150,768,089
Cash and cash equivalents at end of year	$ 10,284,180	$ 21,059,519	$ 104,229,709

Supplemental disclosures of cash flow information (Note 14)

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

Matador Resources Company and Subsidiaries
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2011, 2010 and 2009

NOTE 1 — NATURE OF OPERATIONS

Matador Resources Company ("Matador" or the "Company") is an independent energy company engaged in the exploration, development, production and acquisition of oil and natural gas resources in the United States, with a particular emphasis on oil and natural gas shale plays and other unconventional resource plays. Matador's current operations are located primarily in the Eagle Ford shale play in south Texas and the Haynesville shale play in northwest Louisiana and east Texas. In addition to these primary operating areas, Matador has acreage positions in southeast New Mexico and west Texas and in southwest Wyoming and adjacent areas in Utah and Idaho where the Company continues to identify new oil and natural gas prospects.

On November 22, 2010, the company formerly known as Matador Resources Company, a Texas corporation founded on July 3, 2003, formed a wholly-owned subsidiary, Matador Holdco, Inc. Pursuant to the terms of a corporate reorganization that was completed on August 9, 2011, the former Matador Resources Company became a wholly owned subsidiary of Matador Holdco, Inc. and changed its corporate name to MRC Energy Company, and Matador Holdco, Inc. changed its corporate name to Matador Resources Company.

MRC Energy Company holds the primary assets of the Company and has four wholly owned subsidiaries: Matador Production Company, MRC Permian Company, MRC Rockies Company and Longwood Gathering and Disposal Systems GP, Inc. Matador Production Company serves as the oil and natural gas operating entity. MRC Permian Company conducts oil and natural gas exploration and development activities in southeast New Mexico. MRC Rockies Company conducts oil and natural gas exploration and development activities in the Rocky Mountains and specifically in the states of Wyoming, Utah and Idaho. Longwood Gathering and Disposal Systems GP, Inc. serves as the general partner of Longwood Gathering and Disposal Systems, LP which owns a majority of the pipeline systems and salt water disposal wells used in the Company's operations and also transports limited quantities of third-party natural gas.

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

The consolidated financial statements include the accounts of Matador Resources Company and its wholly owned subsidiary, MRC Energy Company, as well as the accounts of MRC Energy Company's four wholly owned subsidiaries, Matador Production Company, Longwood Gathering and Disposal Systems, GP, Inc., MRC Permian Company and MRC Rockies Company, and the accounts of Longwood Gathering and Disposal Systems, LP. These consolidated financial statements have been prepared in accordance with generally accepted accounting principles in the United States of America ("U.S. GAAP"). The Company's operations are conducted in the one segment generally referred to as the oil and natural gas exploration and production industry. All significant intercompany balances and transactions have been eliminated in consolidation.

Reclassifications

Certain reclassifications have been made to the prior years' financial statements to conform to the current year presentation. These reclassifications had no effect on previously reported results of operations, cash flows or retained earnings.

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES — Continued

Use of Estimates

The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. These estimates and assumptions may also affect disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. While the Company believes its estimates are reasonable, changes in facts and assumptions or the discovery of new information may result in revised estimates. Actual results could differ from these estimates.

The Company's consolidated financial statements are based on a number of significant estimates, including oil and natural gas revenues, accrued assets and liabilities, stock-based compensation, valuation of derivative instruments, deferred tax assets and liabilities and oil and natural gas reserves. The estimates of oil and natural gas reserves quantities and future net cash flows are the basis for the calculations of depletion and impairment of oil and natural gas properties, as well as estimates of asset retirement obligations and certain tax accruals. The Company's oil and natural gas reserves estimates, which are inherently imprecise and based upon many factors that are beyond the Company's control, including oil and natural gas prices, are prepared by the Company's engineering staff in accordance with guidelines established by the Securities and Exchange Commission ("SEC") and then audited for their reasonableness and conformance with SEC guidelines by Netherland, Sewell & Associates, Inc., independent reservoir engineers.

Cash and Cash Equivalents

The Company considers all highly liquid investments with an original maturity of thirty (30) days or less as cash equivalents, and cash equivalents are recorded at market. Except for small cash balances held in the Company's operating accounts to conduct its ongoing business, the remainder of the Company's cash equivalents as of December 31, 2010 was held in money market accounts composed of United States Treasury securities offering daily liquidity. The Company had no cash equivalents as of December 31, 2011.

Certificates of Deposit

Certificates of deposit ("CD's") are highly liquid, short-term investments with an original maturity of more than 30 days but not more than one year. Each CD is recorded at market and is fully insured by the Federal Deposit Insurance Corporation.

Accounts Receivable

The Company sells its operated oil and natural gas production to various purchasers (see Note 13). Due to the nature of the markets for oil and natural gas, the Company does not believe that the loss of any one purchaser would significantly impact operations. In addition, the Company may participate with industry partners in the drilling, completion and operation of oil and natural gas wells. Substantially all of the Company's accounts receivable are due from either purchasers of oil and natural gas or participants in oil and natural gas wells for which the Company serves as the operator. Accounts receivable are due within 30

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES — Continued

to 45 days of the production or billing date and are stated at amounts due from purchasers and industry partners.

The Company reviews its need for an allowance for doubtful accounts on a periodic basis, and determines the allowance, if any, by considering the length of time past due, previous loss history, future net revenues of the debtor's ownership interest in oil and natural gas properties operated by the Company and the debtor's ability to pay its obligations, among other things. The Company has no allowance for doubtful accounts related to its accounts receivable for any reporting period presented.

The Company wrote off receivables of $24,229 in 2011; there were no receivables written off in 2010 or 2009. When necessary, the Company accounts for a write off by recording the loss as a reduction of accounts receivable once the specific account has been determined to be uncollectible.

Lease and Well Equipment Inventory

Lease and well equipment inventory is stated at the lower of cost or market and consists entirely of equipment scheduled for use in future well operations or equipment held for sale.

Property and Equipment

The Company uses the full-cost method of accounting for its investments in oil and natural gas properties. Under this method of accounting, all costs associated with the acquisition, exploration and development of oil and natural gas properties and reserves, including unproved and unevaluated property costs, are capitalized as incurred and accumulated in a single cost center representing the Company's activities, which are undertaken exclusively in the United States. Such costs include lease acquisition costs, geological and geophysical expenditures, lease rentals on undeveloped properties, costs of drilling both productive and non-productive wells, capitalized interest on qualifying projects and general and administrative expenses directly related to acquisition, exploration and development activities, but do not include any costs related to production, selling or general corporate administrative activities. The Company capitalized $2,020,486, $1,604,682 and $1,642,868 of its general and administrative costs in 2011, 2010 and 2009, respectively. The Company capitalized $1,278,383 of its interest expense for the year ended December 31, 2011. The Company recorded only $3,235 in interest expense for the year ended December 31, 2010 and had no outstanding borrowings in 2009. As a result, the Company capitalized no interest expense for the years ended December 31, 2010 and 2009.

The net capitalized costs of oil and natural gas properties are limited to the lower of unamortized costs less related deferred income taxes or the cost ceiling, with any excess above the cost center ceiling charged to operations as a full-cost ceiling impairment. Beginning January 1, 2011, the need for a full-cost ceiling impairment is assessed on a quarterly basis. The cost center ceiling is defined as the sum of (a) the present value discounted at 10 percent of future net revenues of proved oil and natural gas reserves, plus (b) unproved and unevaluated property costs not being amortized, plus (c) the lower of cost or estimated fair value of unproved and unevaluated properties included in the costs being amortized, if any, less (d) income tax effects related to the properties involved. Future net revenues from proved non-producing and proved undeveloped reserves are reduced by the estimated costs for developing these reserves. The fair value of the

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES — Continued

Company's derivative instruments is not included in the ceiling test computation as the Company does not designate these instruments as hedge instruments for accounting purposes.

The estimated present value of after-tax future net cash flows from proved oil and natural gas reserves is highly dependent on the commodity prices used in these estimates. These estimates are determined in accordance with guidelines established by the SEC for estimating and reporting oil and natural gas reserves. Under these guidelines, oil and natural gas reserves are estimated using then-current operating and economic conditions, with no provision for price and cost escalations in future periods except by contractual arrangements. In January 2009, the SEC issued *The Modernization of Oil and Gas Reporting, Final Rule* and in January 2010, the Financial Accounting Standards Board ("FASB") amended *Topic 932, Extractive Activities — Oil and Gas* to align with this rule. As a result, beginning December 31, 2009, the commodity prices used to estimate oil and natural gas reserves are based on unweighted, arithmetic averages of first-day-of-the-month oil and natural gas prices for the previous 12-month period. For the period January through December 31, 2011, these average oil and natural gas prices were $92.71 per barrel and $4.118 per MMBtu (million British thermal units), respectively. For the period January through December 2010, these average oil and natural gas prices were $75.96 per barrel and $4.376 per MMBtu, respectively. For the period January through December 2009, these average oil and natural gas prices were $57.65 per barrel and $3.866 per MMBtu, respectively. In estimating the present value of after-tax future net cash flows from proved oil and natural gas reserves, the average oil prices were further adjusted by property for quality, transportation fees and regional price differentials, and the average natural gas prices were further adjusted by property for energy content, transportation fees and regional price differentials.

During the first quarter ended March 31, 2011, the Company's net capitalized costs less related deferred income taxes exceeded the full-cost ceiling by $22,989,866. The Company recorded an impairment charge of $35,673,098 to its net capitalized costs and a deferred income tax credit of $12,683,232 related to the full-cost ceiling limitation. These charges are reflected in the Company's consolidated statement of operations for the year ended December 31, 2011. Using the average commodity prices, as adjusted, to determine the Company's estimated proved oil and natural gas reserves at December 31, 2011, the Company's net capitalized costs did not exceed the cost center ceiling. Changes in oil and natural gas production rates, reserves estimates, future development costs and other factors will determine the Company's actual ceiling test computation and impairment analyses in future periods.

Using the average commodity prices, as adjusted, for 2010 to determine the Company's estimated proved oil and natural gas reserves at December 31, 2010, the Company's net capitalized costs less related deferred income taxes did not exceed the full-cost ceiling. As a result, the Company recorded no impairment to its net capitalized costs and no corresponding charge to its consolidated statement of operations for 2010.

Using the average commodity prices, as adjusted, for 2009 to determine the Company's estimated proved oil and natural gas reserves at December 31, 2009, the Company's net capitalized costs less related deferred income taxes exceeded the full-cost ceiling by $16,267,822. The Company recorded an impairment charge of $25,243,738 to its net capitalized costs and a deferred income tax credit of $8,975,916 related to the full-cost ceiling limitation for 2009. Corresponding charges were also recorded to the Company's consolidated statement of operations for 2009.

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES — Continued

As a non-cash item, the full-cost ceiling impairment impacts the accumulated depletion and the net carrying value of the Company's assets on its balance sheet, as well as the corresponding shareholders' equity, but it has no impact on the Company's net cash flows as reported.

Capitalized costs of oil and natural gas properties are amortized using the unit-of-production method based upon production and estimates of proved reserves quantities. Unproved and unevaluated property costs are excluded from the amortization base used to determine depletion. Unproved and unevaluated properties are assessed for possible impairment on a periodic basis based upon changes in operating or economic conditions. This assessment includes consideration of the following factors, among others: the assignment of proved reserves, geological and geophysical evaluations, intent to drill, remaining lease term, and drilling activity and results. Upon impairment, the costs of the unproved and unevaluated properties are immediately included in the amortization base. Exploratory dry holes are included in the amortization base immediately upon determination that the well is not productive.

Sales of oil and natural gas properties are accounted for as adjustments to net capitalized costs with no gain or loss recognized, unless such adjustments would significantly alter the relationship between net capitalized costs and proved reserves of oil and natural gas. All costs related to production activities and maintenance and repairs are expensed as incurred. Significant workovers that increase the properties' reserves are capitalized.

Other property and equipment are stated at cost. Computer equipment, furniture, software and other equipment are depreciated over their useful life (5 to 7 years) using the straight-line method. Support equipment and facilities include the pipelines and salt water disposal systems owned by Longwood Gathering and Disposal Systems, LP and are depreciated over a 30-year useful life using the straight-line, mid-month convention method. Leasehold improvements are depreciated over the lesser of their useful life or the term of the lease.

Asset Retirement Obligations

The Company recognizes the fair value of an asset retirement obligation in the period in which it is incurred if a reasonable estimate of fair value can be made. The asset retirement obligation is recorded as a liability at its estimated present value, with an offsetting increase recognized in oil and natural gas properties or support equipment and facilities on the balance sheet. Periodic accretion of the discounted value of the estimated liability is recorded as an expense in the consolidated statement of operations. In general, the Company's future asset retirement obligations relate to future costs associated with plugging and abandonment of its oil and natural gas wells, removal of equipment and facilities from leased acreage and returning such land to its original condition. The amounts recognized are based on numerous estimates and assumptions, including future retirement costs, future recoverable quantities of oil and natural gas, future inflation rates and the credit-adjusted risk-free interest rate. Revisions to the liability can occur due to changes in its estimate or if federal or state regulators enact new plugging and abandonment requirements. At the time of actual plugging and abandonment of its oil and natural gas wells, the Company includes any gain or loss associated with the operation in the amortization base to the extent that the actual costs are different from the estimated liability.

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES — Continued

Derivative Financial Instruments

From time to time, the Company uses derivative financial instruments to hedge its exposure to commodity price risk associated with oil and natural gas prices. These instruments consist of put and call options in the form of costless (or zero-cost) collars. A costless collar provides the Company with downside price protection through the purchase of a put option which is financed through the sale of a call option. Because the call option proceeds are used to offset the cost of the put option, this arrangement is initially "costless" to the Company. The Company's derivative financial instruments are recorded on the balance sheet as either an asset or a liability measured at fair value. The Company has elected not to apply hedge accounting for its existing derivative financial instruments, and as a result, the Company recognizes the change in derivative fair value between reporting periods currently in its consolidated statement of operations (see Note 10). The fair value of the Company's derivative financial instruments is determined using purchase and sale information available for similarly traded securities. Realized gains and realized losses from the settlement of derivative financial instruments and unrealized gains and losses from valuation changes in the remaining unsettled derivative financial instruments are reported under "Revenues" in our consolidated statement of operations.

Revenue Recognition

The Company follows the sales method of accounting for its oil and natural gas revenue, whereby it recognizes revenue, net of royalties, on all oil or natural gas sold to purchasers regardless of whether the sales are proportionate to its ownership in the property. Under this method, revenue is recognized at the time oil and natural gas are produced and sold, and the Company accrues for revenue earned but not yet received.

Stock-Based Compensation

Non-qualified stock option expense is typically recognized in the Company's consolidated statement of operations on the date of grant. Incentive stock options vest over four years, and the associated compensation expense is recognized on a straight-line basis over the vesting period. At December 31, 2011, the Company used the fair value method to measure and recognize the liability associated with its outstanding stock options.

Prior to November 22, 2010, all of the Company's outstanding stock options were classified as equity instruments, with all stock-based compensation expense measured on the date of grant and recognized over the vesting period, if any. On November 22, 2010, the Company changed its method of accounting for outstanding stock options, reclassifying all outstanding stock options from equity to liability instruments. This change was made as a result of the Company purchasing shares from certain of its employees to assist them in the exercise of outstanding options of the Company's Class A common stock. At December 31, 2010, the Company measured and recognized the liability associated with its outstanding stock options using the intrinsic value method.

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES — Continued

The Company's consolidated statements of operations for the years ended December 31, 2011, 2010 and 2009 include a stock-based compensation (non-cash) expense of $2,405,825, $897,737, and $656,087, respectively. This stock-based compensation expense includes common stock and treasury stock issuances totaling $230,400, $245,250, and $29,375 in 2011, 2010 and 2009, respectively, paid to members of the Board of Directors and advisors as compensation for their services to the Company.

Income Taxes

The Company accounts for income taxes using the asset and liability approach for financial accounting and reporting. The Company evaluates the probability of realizing the future benefits of its deferred tax assets and provides a valuation allowance for the portion of any deferred tax assets where the likelihood of realizing an income tax benefit in the future does not meet the more likely than not criteria for recognition.

The Company recognizes the tax benefit of an uncertain tax position only if it is more likely than not that the tax position will be sustained upon examination by the taxing authorities based on the technical merits of the position. For tax positions meeting the more-likely-than-not threshold, the amount recognized in the financial statements is the benefit that has a greater than 50 percent likelihood of being realized upon ultimate settlement with the relevant tax authority. Management believes that the material positions taken by the Company would more likely than not be sustained by examination. At December 31, 2011 and 2010, the Company had not established any reserves for, nor recorded any unrecognized tax benefits related to, uncertain tax positions.

When necessary, the Company would include interest assessed by taxing authorities in "Interest expense" and penalties related to income taxes in "Other expense" on its consolidated statements of operations. The Company did not record any interest or penalties related to income tax for the years ended December 31, 2011, 2010 and 2009.

Earnings Per Common Share

The Company reports basic earnings per common share, which excludes the effect of potentially dilutive securities, and diluted earnings per common share, which includes the effect of all potentially dilutive securities, unless their impact is anti-dilutive.

Prior to consummation of the Company's Initial Public Offering in February 2012, the Company had issued two classes of common stock, Class A and Class B. The holders of the Class B shares are entitled to be paid cumulative dividends at a per share rate of $0.26-2/3 annually out of funds legally available for the payment of dividends. These dividends were accrued and paid quarterly. Dividends declared during 2011, 2010 and 2009 totaled $274,853 in each year. The holders of the Class B shares were also entitled to share on an equivalent basis in any dividends paid to holders of the Class A shares when and as declared by the Board of Directors. As of December 31, 2011, the Company has not paid any dividends to holders of the Class A shares.

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES — Continued

The following are reconciliations of the numerators and denominators used to compute the Company's basic and diluted distributed and undistributed earnings per common share as reported for the years ended December 31, 2011, 2010 and 2009.

	Year ended December 31,		
	2011	2010	2009
Net income (loss) — numerator			
Net (loss) income	$(10,309,013)	$ 6,376,963	$(14,425,342)
Less dividends to Class B shareholders — distributed earnings	(274,853)	(274,853)	(274,853)
Undistributed (loss) earnings	$(10,583,866)	$ 6,102,110	$(14,700,195)
Weighted average common shares outstanding — denominator			
Basic			
Class A	41,686,807	40,006,787	39,092,567
Class B	1,030,700	1,030,700	1,030,700
Total	42,717,507	41,037,487	40,123,267
Diluted			
Class A			
Weighted average common shares outstanding for basic earnings (loss) per share	41,686,807	40,006,787	39,092,567
Dilutive effect of options	–	96,140	–
Class A weighted average common shares outstanding — diluted	41,686,807	40,102,927	39,092,567
Class B			
Weighted average common shares outstanding — no associated dilutive shares	1,030,700	1,030,700	1,030,700
Total diluted weighted average common shares outstanding	42,717,507	41,133,627	40,123,267

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES — Continued

	Year ended December 31,		
	2011	2010	2009
Earnings (loss) per common share			
Basic			
Class A			
Distributed earnings	$ –	$ –	$ –
Undistributed (loss) earnings	$(0.25)	$0.15	$(0.37)
Total	$(0.25)	$0.15	$(0.37)
Class B			
Distributed earnings	$ 0.27	$0.27	$ 0.27
Undistributed (loss) earnings	$(0.25)	$0.15	$(0.37)
Total	$ 0.02	$0.42	$(0.10)
Diluted			
Class A			
Distributed earnings	$ –	$ –	$ –
Undistributed (loss) earnings	$(0.25)	$0.15	$(0.37)
Total	$(0.25)	$0.15	$(0.37)
Class B			
Distributed earnings	$ 0.27	$0.27	$ 0.27
Undistributed (loss) earnings	$(0.25)	$0.15	$(0.37)
Total	$ 0.02	$0.42	$(0.10)

A total of 1,024,500 and 1,551,750 options to purchase shares of the Company's Class A common stock were excluded from the calculations above for the years ended December 31, 2011 and 2009, respectively, because their effects were anti-dilutive.

Subsequent to December 31, 2011, all Class B shares were converted to Class A shares (see Note 17).

Fair Value Measurements

The Company measures and reports certain assets and liabilities on a fair value basis. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). The Company follows FASB guidance establishing a fair value hierarchy that prioritizes the inputs to valuation methods used to measure fair value.

The carrying amounts reported on the balance sheet for cash and cash equivalents, certificates of deposit, accounts receivable, prepaid expenses, accounts payable, accrued liabilities, royalties payable, advances from joint interest owners, dividends payable and other current liabilities approximate their fair values, due to the short-term maturity of these instruments.

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES — Continued

At December 31, 2011 and 2010, the carrying values of $113,000,000 and $25,000,000, respectively, for the Company's borrowings under its senior secured revolving Credit Agreement on the consolidated balance sheets approximate fair value as they are subject to short-term floating interest rates that approximate the rates available to the Company at the time.

Credit Risk

The Company uses derivative financial instruments to hedge its exposure to oil and natural gas price volatility. These transactions expose the Company to potential credit risk from its single counterparty. Accounts receivable constitute the principal component of additional credit risk to which the Company may be exposed. The Company believes that any credit risk posed is insignificant and is offset by the credit worthiness of its customer base and industry partners.

Risks and Uncertainties

As an oil and natural gas exploration and production company focused on finding and developing its own prospects and reserves, the Company's success is highly dependent on the results of its exploration program. Exploration activities involve numerous risks, including the risk that no commercially productive oil or natural gas reserves will be discovered. In addition, there are uncertainties as to the future costs or timing of drilling, completing and producing wells. Poor results from the Company's exploration activities could limit the Company's ability to replace and grow reserves and materially and adversely affect the Company's financial position, results of operations and cash flows.

The Company does not operate properties constituting a significant portion of its oil and natural gas reserves. As a result of the Company's sale of certain assets to Chesapeake Louisiana, L.P. ("Chesapeake") in 2008, the Company does not operate its most significant natural gas asset, that being the deep rights to explore for and develop the Haynesville shale formation (underlying its existing Cotton Valley Davis production) on the Company's Elm Grove/Caspiana leasehold in northwest Louisiana. Although the Company has reserved the right to participate for a proportionately reduced 25% working interest in all wells that Chesapeake drills or participates in to develop the Haynesville on this acreage, and although the Company has the right to propose the drilling of Haynesville wells on these properties, the Company may have limited influence on when, how and at what pace these properties are developed. This could impact the Company's ability to replace and grow reserves and materially and adversely affect the Company's financial position, results of operations and cash flows. In addition, in 2011, 2010 and 2009, the Company acquired other non-operated acreage positions in northwest Louisiana that it believes to be prospective for the Haynesville shale. The Company has, or will have, small, non-operated working interests in the Haynesville units including these properties, and as a result, the Company will have limited influence on when, how and at what pace these properties are developed.

Estimating oil and natural gas reserves is complex and is not exact because of the numerous uncertainties inherent in the process. The process relies on interpretations of available geological, geophysical, petrophysical, engineering and production data. The extent, quality and reliability of both the data and the associated interpretations of that data can vary. The process also requires certain economic

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES — Continued

assumptions, including, but not limited to, oil and natural gas prices, drilling and operating expenses, capital expenditures and taxes. Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas most likely will vary from the Company's estimates. Any significant variance could materially and adversely affect the Company's future reserves estimates, financial position, results of operations and cash flows.

Historically, the market for oil and natural gas has experienced significant price fluctuations, and this has been particularly evident in recent years. Oil and natural gas prices are impacted by supply and demand, both domestic and international, seasonal variations caused by changing weather conditions, political conditions, governmental regulations, the availability, proximity and capacity of gathering systems for natural gas and numerous other factors. Increases or decreases in prices received could have a significant and material impact on the Company's future reserves estimates, financial position, results of operations and cash flows.

To mitigate its exposure to fluctuations in oil and natural gas prices, the Company, from time to time, enters into hedging arrangements, typically using put and call options in the form of costless collars, with respect to a portion of its oil and natural gas production. Decisions as to whether and at what production volumes to hedge are difficult and depend on market conditions and the Company's forecast of future production and commodity prices, and the Company may not always employ the optimal hedging strategy.

The federal, state and local governments in the areas in which the Company operates or has assets impose taxes on the oil and gas products sold, and sales and use taxes are charged on significant portions of the Company's drilling, completion and operating costs. Historically, there has been a significant amount of discussion by legislators and presidential administrations concerning a variety of energy tax proposals. President Obama has proposed sweeping changes in federal laws on the income taxation of oil and gas exploration and production companies. President Obama has proposed to eliminate allowing U.S. oil and gas companies to deduct intangible well costs as incurred and percentage depletion, among other proposals. Many states have raised state taxes on energy sources, and additional increases may occur. Changes to tax laws could materially and adversely affect the Company's future financial position, results of operations and cash flows.

Recent Accounting Pronouncements

Balance Sheet. In December 2011, the FASB issued Accounting Standards Update, or ASU, 2011-11, *Balance Sheet.* The requirements amend the disclosure requirements related to offsetting in Accounting Standards Codification, or ASC, 210-20-50. The amendments require enhanced disclosures by requiring improved information about financial instruments and derivative instruments that are either (1) offset in accordance with either ASC 210-20-45 or ASC 815-10-45 or (2) subject to an enforceable master netting arrangement or similar agreement, irrespective of whether they are offset in accordance with either ASC 210-20-45 or ASC 815-10-45. The adoption of ASU 2011-11 is not expected to have a material effect on the Company's consolidated financial statements, but may require certain additional disclosures. The amendments in ASU 2011-11 are to be applied for annual reporting periods beginning on or after January 1, 2013 and are to be applied retrospectively for all periods presented.

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES — Continued

Fair Value. In May 2011, the FASB issued ASU 2011-04, *Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS* ("ASU 2011-04"). ASU 2011-04 amends ASC 820 *Fair Value Measurements*, providing a consistent definition and measurement of fair value, as well as similar disclosure requirements between U.S. GAAP and International Financial Reporting Standards. ASU 2011-04 changes certain fair value measurement principles, clarifies the application of existing fair value measurements and expands the ASC 820 disclosure requirements, particularly for Level 3 fair value measurements. The adoption of ASU 2011-04 is not expected to have a material effect on the Company's consolidated financial statements, but may require certain additional disclosures. The amendments in ASU 2011-04 are to be applied prospectively. The amendments are effective during interim and annual periods beginning after December 15, 2011.

In January 2010, the FASB issued authoritative guidance to update certain disclosure requirements and added two new disclosure requirements to fair value measurements. The guidance requires a gross presentation of activities within the Level 3 roll forward and adds a new requirement to disclose details of significant transfers in and out of Level 1 and 2 measurements and the reasons for the transfers. The new disclosures are required for all companies that are required to provide disclosures about recurring and non-recurring fair value measurements and are effective for the first interim or annual reporting period beginning after December 15, 2009, except for the gross presentation of Level 3 roll forward information, which is required for annual reporting periods beginning after December 15, 2010 and for interim reporting periods within those years. The Company adopted the first portion of this guidance beginning January 1, 2010, and the remaining provisions beginning January 1, 2011. The adoption of this guidance did not have a significant impact on the Company's financial position, results of operations or cash flows.

Oil and Natural Gas Reserves Reporting Requirements. In January 2009, the SEC issued *The Modernization of Oil and Gas Reporting, Final Rule.* In January 2010, the FASB amended *Topic 932, Extractive Activities — Oil and Gas* to align with this rule. The changes are designed to modernize and update the oil and gas disclosure requirements to align them with current practices and changes in technology. The new rules made a number of important changes including the following: (1) expanded the definition of oil and gas producing activities to include the extraction of saleable hydrocarbons from oil sands, shale coalbeds or other nonrenewable natural resources, (ii) amended the required price for estimating economic quantities for year-end reserves reporting to be the unweighted, arithmetic average of the first-day-of-the-month price for each month within the previous 12-month period, rather than the year-end price, and (iii) permitted proved reserves to be claimed beyond those development spacing areas that are immediately adjacent to developed spacing areas if it can be established with reasonable certainty that these reserves are economically producible. At December 31, 2009, the Company adopted the provisions of this new rule, and the Company has applied this new guidance for the reserves estimates at December 31, 2011, 2010 and 2009 included herein.

NOTE 3 — PROPERTY AND EQUIPMENT

The following table presents a summary of the Company's property and equipment balances as of December 31, 2011 and 2010.

	December 31, 2011	December 31, 2010
Oil and natural gas properties		
Evaluated (subject to amortization)	$ 423,944,476	$ 255,408,993
Unproved and unevaluated (not subject to amortization)		
Incurred in 2011	60,934,015	–
Incurred in 2010	80,592,790	121,950,288
Incurred in 2009	8,206,954	14,267,810
Incurred in 2008 and prior	12,864,226	36,233,351
Total unproved and unevaluated	162,597,985	172,451,449
Total oil and natural gas properties	586,542,461	427,860,442
Accumulated depletion	(201,542,468)	(134,700,857)
Net oil and natural gas properties	384,999,993	293,159,585
Other property and equipment		
Computer equipment	786,540	685,493
Furniture	458,347	416,095
Software	1,110,890	1,000,558
Other equipment	194,215	111,450
Leasehold improvements	626,583	65,899
Support equipment and facilities	15,587,463	11,755,515
Total other property and equipment	18,764,038	14,035,010
Accumulated depreciation	(3,899,256)	(3,314,129)
Net other property and equipment	14,864,782	10,720,881
Net property and equipment	$ 399,864,775	$ 303,880,466

The following table provides a breakdown of the Company's unproved and unevaluated property costs not subject to amortization as of December 31, 2011 and the year in which these costs were incurred.

Description	2011	2010	2009	2008 and prior	Total
Costs incurred for					
Property acquisition	$40,435,891	$80,592,790	$8,206,954	$12,864,226	$142,099,861
Exploration wells	16,682,802	–	–	–	16,682,802
Development wells	2,812,615	–	–	–	2,812,615
Capitalized interest	1,002,707	–	–	–	1,002,707
Total	$60,934,015	$80,592,790	$8,206,954	$12,864,226	$162,597,985

NOTE 3 — PROPERTY AND EQUIPMENT — Continued

Property acquisition costs primarily include leasehold costs paid to secure oil and gas mineral leases, but may also include broker and legal expenses, geological and geophysical expenses and capitalized internal costs associated with developing oil and natural gas prospects on these properties. Property acquisition costs are transferred into the amortization base on an ongoing basis as these properties are evaluated and proved reserves are established or impairment is determined. Unproved and unevaluated properties are assessed for possible impairment on a periodic basis based upon changes in operating or economic conditions.

Property acquisition costs incurred in 2011 were primarily related to the Company's leasing and acquisition activities in the Eagle Ford shale play in south Texas. Between March and July 2011, the Company acquired leasehold interests in approximately 6,300 gross and 4,800 net acres in DeWitt, Karnes, Wilson and Gonzales Counties, Texas in the Eagle Ford shale play from Orca ICI Development, JV. The Company paid approximately $31.5 million to acquire this acreage, and only one well has been drilled and completed on these properties at December 31, 2011. The remaining property acquisition costs incurred in 2011 were related to the Company's leasing activities in the Haynesville shale play in northwest Louisiana. Portions of these costs will be transferred to the amortization base periodically as the Company drills wells and assigns proved reserves to these properties or determines that certain portions of this acreage, if any, cannot be assigned proved reserves. The Company estimates that evaluation of most of these properties and the inclusion of their costs in the amortization base is expected to be completed within three to five years.

The 2010 and 2009 property acquisition costs were also related primarily to the Company's leasing activities in the Eagle Ford and Haynesville shale plays. These costs are associated with acreage for which proved reserves have yet to be assigned. As the Company drills wells and assigns proved reserves to these properties or determines that certain portions of this acreage, if any, cannot be assigned proved reserves, portions of these costs are transferred to the amortization base. The Company estimates that evaluation of most of these properties and the inclusion of their costs in the amortization base is expected to be completed within three to five years.

Property acquisition costs incurred in 2008 and prior years were related primarily to the Company's leasing activities in the Haynesville shale play in northwest Louisiana and in southwest Wyoming, northeast Utah and southeast Idaho. During 2011, the Company drilled its first exploration well on its acreage in southwest Wyoming. The Company estimates that evaluation of most of these properties and the inclusion of their costs in the amortization base is expected to be completed within two to five years.

Costs excluded from amortization also include those costs associated with exploration and development wells in progress or awaiting completion at year-end. These costs are transferred into the amortization base on an ongoing basis, as these wells are completed and proved reserves are established or confirmed. These costs totaled $19,495,417 at December 31, 2011. Of this total, $16,682,802 was associated with exploration wells and $2,812,615 was associated with development wells. The Company anticipates that the entire $19,495,417 associated with these wells in progress at December 31, 2011 will be transferred to the amortization base during 2012. At December 31, 2011, there were no well costs excluded from amortization that were incurred in years prior to 2011.

NOTE 4 — ASSET RETIREMENT OBLIGATIONS

The following table summarizes the changes in the Company's asset retirement obligations for the years ended December 31, 2011 and 2010.

	Year ended December 31,	
	2011	2010
Beginning asset retirement obligations	$3,695,017	$2,551,637
Liabilities incurred during period	186,873	847,845
Revisions in estimated cash flows	312,187	140,779
Liabilities settled during period	(133,040)	–
Accretion expense	208,547	154,756
Ending asset retirement obligations	$4,269,584	$3,695,017

At December 31, 2011 and 2010, $334,500 and $131,166, respectively, of the Company's asset retirement obligations were reclassified as current liabilities and included in "accrued liabilities" in the Company's consolidated balance sheets.

NOTE 5 — ASSET SALES AND IMPAIRMENT

In December 2011, the Company recorded an impairment to some of its equipment held in inventory following a determination that the current market value of the equipment, consisting primarily of drilling rig parts, was less than the cost. The carrying value of the inventory was reduced by $17,500 on the balance sheet, and a corresponding charge was recorded to the consolidated statement of operations. In December 2011, the Company also recorded an impairment to some of its equipment held in inventory following a determination that the current market value of the equipment, consisting primarily of pipe and other equipment, was less than the cost. The carrying value of the inventory was reduced by $22,276 on the balance sheet, and a corresponding charge was recorded to the consolidated statement of operations. In addition, the Company recorded a loss of $113,757 on certain other equipment that was sold during 2011.

In December 2010, the Company wrote off the Boise South Pipeline asset in Orange County, Texas from its Longwood Gathering and Disposal Systems, LP subsidiary and recorded a net loss of $173,690. The decision to write off this asset resulted from the fact that natural gas was no longer being put through this pipeline, nor was natural gas expected to be put through this pipeline in the future. In December 2010, the Company also recorded an impairment to some of its equipment held in inventory following a determination that the current market value of the equipment, consisting primarily of drilling rig parts, was less than the cost. The carrying value of the inventory was reduced by $50,000 on the balance sheet, and a corresponding charge was recorded to the consolidated statement of operations.

In December 2009, the Company recorded an impairment to some of its equipment held in inventory following a determination that the current market value of the equipment, consisting primarily of drilling rig parts, was less than the cost. The carrying value of the inventory was reduced by $323,500 on the balance sheet, and a corresponding charge was recorded to the consolidated statement of operations. In addition, the Company recorded a loss of $55,816 on certain other equipment that was sold during 2009.

NOTE 6 — REVOLVING CREDIT AGREEMENT

In December 2011, the Company amended and restated its senior secured revolving credit agreement ("Credit Agreement") for which Comerica Bank serves as administrative agent. This amendment increased the maximum facility amount from $150,000,000 to $400,000,000. Borrowings under the Credit Agreement are limited to the lesser of $400,000,000 or the borrowing base. At December 31, 2011, the borrowing base was $125,000,000, and the Company had $113,000,000 of outstanding borrowings plus an additional $1,262,934 in letters of credit issued pursuant to the Credit Agreement. At December 31, 2011, all borrowings under the Credit Agreement bore interest at approximately 5.3% per annum. The Credit Agreement matures in December 2016. In February 2012, the Company repaid all then outstanding borrowings under its Credit Agreement, and in March 2012, the Company borrowed $15,000,000 under the Credit Agreement (see Note 17).

MRC Energy Company is the borrower under the Credit Agreement and borrowings are secured by mortgages on substantially all of the Company's oil and natural gas properties and by the equity interests of all of MRC Energy Company's wholly owned subsidiaries, which are also guarantors. In addition, all obligations under the Credit Agreement are guaranteed by Matador Resources Company, the parent corporation. Various commodity hedging agreements with Comerica Bank (or an affiliate thereof) are also secured by the collateral and guaranteed by the subsidiaries of MRC Energy Company.

The Company incurred $722,821 of additional deferred loan costs in connection with the amendment and restatement of the Credit Agreement in December 2011. These costs were included with the remaining unamortized portion of the deferred loan fees of $164,240 incurred when the Company entered into the Credit Agreement in March 2008. As a result, total deferred loan costs are $887,061 at December 31, 2011, and these costs are being amortized over the term of the agreement, which approximates the amortization of these costs using the effective interest method.

The Company previously entered into the Credit Agreement in March 2008, with a maturity date of March 2013. The Company amended and restated the Credit Agreement for the first time in May 2011, increasing the borrowing base at that time from $55,000,000 to $80,000,000. In addition to the Company's revolving borrowings under the Credit Agreement, in May 2011, the Company also borrowed $25,000,000 under a term loan pursuant to the Credit Agreement. The term loan was due and payable on December 31, 2011 and there was no penalty for prepayment. This term loan was refinanced by revolving borrowings under the amended and restated Credit Agreement in December 2011.

The borrowing base under the Credit Agreement is determined semi-annually as of May 1 and November 1 by the lenders based primarily on the estimated value of the Company's existing and future acquired oil and gas reserves, but also on external factors, such as the lenders' lending policies and the lenders' estimates of future oil and natural gas prices, over which the Company has no control. At December 31, 2011, the borrowing base was $125,000,000, and the Company was required to repay $25,000,000 prior to December 31, 2012. Upon repayment of the $25,000,000 or any additional amounts above $25,000,000, the borrowing base would then be reduced to $100,000,000 until any subsequent redetermination of the borrowing base under the agreement.

NOTE 6 — REVOLVING CREDIT AGREEMENT — Continued

Both the Company and the lenders may each request an unscheduled redetermination of the borrowing base twice at any time during the first year of the Credit Agreement and once between scheduled redetermination dates thereafter. We requested one such unscheduled redetermination in February 2012 (see Note 17). In the event of a borrowing base increase, the Company is required to pay a fee to the lenders equal to a percentage of the amount of the increase, which will be determined based on market conditions at the time of the borrowing base increase. If the borrowing base were to be less than the outstanding borrowings under the Credit Agreement at any time, the Company would be required to provide additional collateral satisfactory in nature and value to the lenders to increase the borrowing base to an amount sufficient to cover such excess or to repay the deficit in equal installments over a period of six months.

If the Company borrows funds as a base rate loan, such borrowings will bear interest at a rate equal to the higher of (i) the weighted average of rates used in overnight federal funds transactions with members of the Federal Reserve System plus 1.0% or (ii) the prime rate for Comerica Bank then in effect or (iii) a daily adjusted LIBOR rate plus 1.0% plus, in each case, an amount from 0.375% to 1.75% of such outstanding loan depending on the level of borrowings under the agreement. If the Company borrows funds as a Eurodollar loan, such borrowings will bear interest at a rate equal to (i) the quotient obtained by dividing (A) the interest rate appearing on Page BBAM of the Bloomberg Financial Markets Information Service by (B) a percentage equal to 100% minus the maximum rate during such interest calculation period at which Comerica Bank is required to maintain reserves on Eurocurrency Liabilities (as defined in Regulation D of the Board of Governors of the Federal Reserve System), plus (ii) an amount from 1.375% to 2.75% of such outstanding loan depending on the level of borrowings under the agreement. The interest period for Eurodollar borrowings may be one, two, three or six months as designated by the Company. A facility fee of 0.375% to 0.50%, depending on the amounts borrowed, is also paid quarterly in arrears. The Company includes this facility fee in its interest rate calculations and related disclosures.

Key financial covenants under the Credit Agreement require us to maintain (1) a minimum current ratio, which is defined as consolidated total current assets plus the unused availability under the Credit Agreement divided by consolidated total current liabilities, of 1.0 or greater measured at the end of each fiscal quarter beginning March 31, 2012, and (2) a debt to EBITDA ratio, which is defined as total debt outstanding divided by a rolling four quarter EBITDA calculation, of 4.0 to 1.0 or less beginning on December 31, 2011.

Subject to certain exceptions, the Credit Agreement contains various covenants that limit the Company's, along with its subsidiaries', ability to take certain actions, including, but not limited to, the following:

- incur indebtedness or grant liens on any of its assets;
- enter into commodity hedging agreements;
- declare or pay dividends, distributions or redemptions;
- merge or consolidate;

NOTE 6 — REVOLVING CREDIT AGREEMENT — Continued

- make any loans or investments;
- engage in transactions with affiliates; and
- engage in certain asset dispositions, including a sale of all or substantially all of the Company's assets.

If an event of default exists under the Credit Agreement, the lenders will be able to accelerate the maturity of the borrowings and exercise other rights and remedies. Events of default include, but are not limited to, the following events:

- failure to pay any principal or interest on the notes or any reimbursement obligation under any letter of credit when due or any fees or other amount within certain grace periods;
- failure to perform or otherwise comply with the covenants and obligations in the credit agreement or other loan documents, subject, in certain instances, to certain grace periods;
- bankruptcy or insolvency events involving the Company or its subsidiaries; and
- a change of control, as defined in the Credit Agreement.

The Company believes that it was in compliance with the terms of the Credit Agreement and with all its bank covenants at December 31, 2011. We obtained a written extension until May 1, 2012 to comply with a covenant under the Credit Agreement requiring the submission of certain year-end 2011 operating information on or before March 1, 2012.

The following table presents the approximate maturities of amounts outstanding under the Credit Agreement as of December 31, 2011.

Year ending December 31,	Amount
2012	$ 25,000,000
2013	–
2014	–
2015	–
2016	88,000,000
Total	$113,000,000

In December 2010, the Credit Agreement was amended to increase the borrowing base to $55,000,000. At December 31, 2010, the Company had $25,000,000 of outstanding borrowings and $50,000 in letters of credit issued pursuant to the Credit Agreement. At December 31, 2010, all borrowings under the Credit Agreement were Eurocurrency loans, and the interest rate on the outstanding borrowings was approximately 1.6%. The Company had an additional $325,000 in letters of credit secured by certificates of deposit at Comerica Bank at December 31, 2010.

NOTE 7 — INCOME TAXES

Deferred tax assets and liabilities are the result of temporary differences between the financial statement carrying values and the tax bases of assets and liabilities. The Company's net deferred tax position as of December 31, 2011 and 2010, respectively, is as follows.

	December 31,	
	2011	2010
Deferred tax assets		
Net operating loss — federal and state	$ 24,047,022	$ 21,768,007
Federal alternative minimum tax	6,659,528	6,659,528
Total deferred tax assets	30,706,550	28,427,535
Deferred tax liabilities		
Property and equipment	(26,956,869)	(33,800,718)
Unrealized gain on derivatives	(3,322,255)	(1,473,619)
Other	(1,857,855)	(59,455)
Total deferred tax liabilities	(32,136,979)	(35,333,792)
Total net deferred tax liabilities	$ (1,430,429)	$ (6,906,257)

At December 31, 2011 and 2010, the Company recorded $3,023,760 and $1,473,619 of its deferred tax liabilities as current; these liabilities were attributable to the current portion of its unrealized derivative fair value.

At December 31, 2011, the Company had net operating loss carryforwards of $64,207,377 for federal income tax purposes and $58,477,725 for state income tax purposes available to offset future taxable income, as limited by the applicable provisions, and which expire at various dates beginning December 31, 2027 for the federal net operating loss carryforwards. The state net operating loss carryforwards expire at various dates beginning December 31, 2012 for the state of New Mexico; however, the significant portion of the Company's state net operating loss carryforwards expire beginning in 2027.

As noted previously, the Company recorded an impairment charge of $22,989,866 to its net capitalized costs, net of a deferred income tax credit of $12,683,232 related to the full-cost ceiling limitation during the first quarter ended March 31, 2011. This deferred income tax credit exceeded the Company's deferred tax liabilities at March 31, 2011. As a result, the Company established a valuation allowance at March 31, 2011 and retained a valuation allowance until the fourth quarter of the year ended December 31, 2011 due to uncertainties regarding the future realization of its deferred tax assets. At December 31, 2011, the Company assessed the valuation allowance and determined that an allowance was no longer required as the remaining deferred tax assets are expected to be realized in future periods.

NOTE 7 — INCOME TAXES — Continued

The income tax expense reconciled to the tax computed at the statutory federal rate for the years ended December 31, 2011, 2010 and 2009, respectively, is as follows.

	Year ended December 31,		
	2011	2010	2009
Current income tax (benefit) provision			
State income tax	$ (45,576)	$ 30	$ (994,504)
Federal alternative minimum tax	–	(1,410,638)	(1,329,834)
Net current income tax benefit	(45,576)	(1,410,608)	(2,324,338)
Deferred income tax provision (benefit)			
Federal tax expense at statutory rate (34%)	(5,319,101)	3,365,367	(7,941,036)
Statutory depletion carryforward	230,707	(157,278)	(610,013)
State income tax	(435,379)	–	–
Change in state rate applied	–	275,030	(158,638)
Nondeductible expense	47,945	38,026	41,857
Dividends received deduction	–	–	(262,815)
Federal alternative minimum tax	–	1,410,638	1,329,834
Net deferred income tax (benefit)provision	(5,475,828)	4,931,783	(7,600,811)
Total income tax (benefit) provision	$(5,521,404)	$ 3,521,175	$(9,925,149)

The Company files a United States federal income tax return and several state tax returns, a number of which remain open for examination. The tax years open for examination for the federal tax return are 2007, 2008, 2009, 2010 and 2011. The tax years open for examination by the state of Texas are 2007, 2008, 2009, 2010 and 2011. The tax years open for examination by the state of New Mexico are 2008, 2009, 2010 and 2011. The tax years open for examination by the state of Louisiana are 2007, 2008, 2009, 2010 and 2011. As of December 31, 2011, the Company's 2007, 2008 and 2009 income and franchise tax returns are under examination by the state of Louisiana. As a result of preliminary findings received by the Company from the state of Louisiana, the Company has recorded an income tax refund of approximately $46,000 for the year ended December 31, 2011.

NOTE 8 — EMPLOYEE BENEFIT PLANS

Stock Options, Restricted Stock Grants and Performance Awards

In 2003 the Company's Board of Directors and shareholders approved the Matador Resources Company 2003 Stock and Incentive Plan ("Stock and Incentive Plan"). The Stock and Incentive Plan, as amended, provides that a maximum of 3,481,569 shares of Class A common stock in the aggregate may be issued pursuant to options or restricted stock grants. The persons eligible to receive awards under the Stock and Incentive Plan include employees, directors, officers, consultants or advisors of the Company.

NOTE 8 — EMPLOYEE BENEFIT PLANS — Continued

The Stock and Incentive Plan is administered by the Board of Directors, which determines the number of options or restricted shares to be granted, the effective dates and terms of the grants, the option or restricted share price, and the vesting period. Incentive stock options become exercisable in one to four years from the grant date and expire five years or ten years after the grant date. Non-qualified options become exercisable immediately upon grant and expire five years after the grant date. In the absence of an established market for shares of the Company's common stock, the Board of Directors determines the fair market value of the Company's common stock for purposes of awards under the Stock and Incentive Plan. The Company typically uses newly issued shares of common stock to satisfy option exercises or restricted share grants.

Non-qualified stock option expense is typically recognized in the Company's consolidated statement of operations on the date of grant. Incentive stock option expense is recognized on a straight-line basis over the vesting period. Prior to November 22, 2010, all of the Company's outstanding stock options were classified as equity instruments, with all stock-based compensation expense measured on the date of grant and recognized over the vesting period, if any.

Prior to November 22, 2010, the fair value of stock options granted under the Stock and Incentive Plan was estimated using the following weighted average assumptions for 2010 and 2009, respectively.

	Year ended December 31,	
	2010	2009
Stock option pricing model	Binomial Lattice	Binomial Lattice
Expected option life	5.41 years	3.73 years
Risk-free interest rate	2.58%	2.43%
Volatility	46.17%	52.55%
Dividend yield	0.0%	0.0%
Estimated forfeiture rate	11.15%	3.39%
Weighted average fair value of options granted during the year	$3.02	$1.82

On November 22, 2010, the Company changed its method of accounting for its outstanding stock options, reclassifying all outstanding stock options from equity to liability instruments (see Note 2). At December 31, 2010, the Company measured and recognized the liability associated with its outstanding stock options using the intrinsic value method and an estimated fair value of $11.00 per share for the Company's Class A common stock

Effective upon filing our initial Registration Statement with the SEC in August 2011, the Company adopted the fair value method and used an estimated fair value of $12.00 per share to measure and recognize the liability associated with its outstanding stock options. The Company recorded $1,129,336 in additional general and administrative expenses during 2011 due to this change in the valuation method from the intrinsic value method to the fair value method.

NOTE 8 — EMPLOYEE BENEFIT PLANS — Continued

The Company granted no stock options during the year ended December 31, 2011. The fair value of stock options outstanding under the Stock and Incentive Plan was estimated using the following weighted average assumptions at December 31, 2011.

Stock option pricing model	Black Scholes Merton
Expected option life	1.04 years
Risk-free interest rate	0.37%
Volatility	61.41%
Dividend yield	0.00%
Estimated forfeiture rate	1.04%

The Company estimated the future volatility of its Class A common stock using the historical value of its peer group for a period of time commensurate with the expected term of the stock option due to the lack of historical trading data available for its common stock. The expected term was estimated using the simplified method outlined in Staff Accounting Bulletin Topic 14. The risk free interest rate is the rate for constant yield U.S. Treasury securities with a term to maturity that is consistent with the expected term of the award.

Summarized information about stock options outstanding under the Company's Stock and Incentive Plan is as follows.

	Number of options	Price per share	Aggregate option price	Weighted average exercise price
Options outstanding at January 1, 2009	1,887,750		$14,432,500	$ 7.65
Options granted	45,000	$ 7.50	337,500	7.50
Options exercised	(343,500)	3.33-5.00	(1,281,500)	3.73
Options forfeited	(37,500)	3.33-13.33	(360,500)	9.61
Options outstanding at December 31, 2009	1,551,750		$13,128,000	$ 8.46
Options granted	158,000	$9.00-11.00	1,468,000	9.29
Options exercised	(392,375)	5.00-10.00	(1,978,375)	5.04
Options forfeited or expired	(99,875)	5.00-13.33	(773,875)	7.75
Options outstanding at December 31, 2010	1,217,500		$11,843,750	$ 9.73
Options exercised	(93,001)	$ 9.00	(837,009)	9.00
Options forfeited or expired	(99,999)	9.00-13.33	(1,015,991)	10.16
Options outstanding at December 31, 2011	1,024,500		$ 9,990,750	$ 9.75

NOTE 8 — EMPLOYEE BENEFIT PLANS — Continued

	December 31, 2011				
	Options outstanding			Options exercisable	
Range of exercise prices	Shares outstanding	Weighted average remaining contractual life	Weighted average exercise price	Shares exercisable	Weighted average exercise price
$7.50-$9.00	436,750	2.56 years	$ 8.95	337,375	$ 8.97
$10.00-$13.33	587,750	1.39 years	$10.35	460,625	$10.33

At December 31, 2011, the aggregate intrinsic value for the options outstanding was $2,303,435, of which $1,792,273 was exercisable at December 31, 2011 with a weighted average contractual term of 1.60 years.

The total intrinsic value of options exercised during the years ended December 31, 2011, 2010 and 2009 was $186,002, $2,180,125 and $2,153,500, respectively. The tax related benefit realized from the exercise of stock options totaled $16,220, $779,907 and $572,191 for the years ended December 31, 2011, 2010 and 2009, respectively.

During the year ended December 31, 2011, the Company recognized $2,405,825 in stock compensation expense. At December 31, 2010, the Company recognized a total stock-based liability of $1,250,467 resulting from the reclassification of its outstanding stock options from equity to liability instruments, including a charge to shareholders' equity of $1,086,271 and an additional (non-cash) compensation expense of $164,196. The Company recorded $1,095,014 of this stock-based liability as a current liability and $155,453 as a long-term liability. During the year ended December 31, 2009, the Company recorded $656,087 in stock-based compensation costs.

The total tax benefit recognized for stock based compensation was $861,045, $319,208 and $233,355 for the years ended December 31, 2011, 2010 and 2009, respectively.

At December 31, 2011, 2010 and 2009, the total remaining unrecognized compensation expense related to unvested stock options was approximately $642,519, $376,986 and $807,324, respectively, and the weighted average remaining requisite service period (vesting period) of all unvested stock options was approximately 1.18, 1.65 and 1.93 years, respectively.

A summary of the non-vested stock options as of December 31, 2011 is presented below.

Non-vested stock options	Shares	Weighted average fair value
Non-vested at January 1, 2011	517,750	$4.52
Vested	(247,500)	3.86
Forfeited	(43,750)	4.21
Non-vested at December 31, 2011	226,500	$5.30

The fair value of option shares vested during 2011, 2010 and 2009 was $954,558, $2,413,250 and $2,830,592, respectively.

NOTE 8 — EMPLOYEE BENEFIT PLANS — Continued

On October 28, 2010, the Company made a restricted stock grant of 15,000 shares of Class A common stock to an employee. These shares vest according to the following schedule: 3,000 shares were fully vested upon grant, an incremental 4,000 shares vested on October 28, 2011 and an incremental 4,000 shares will vest on each of October 28, 2012 and 2013. Should the employee cease to remain in service with the Company other than by death or disability, all unvested shares will be forfeited.

In October 2008, the Company's Board of Directors approved the adoption of the Employee Share Repurchase Program ("Repurchase Program") authorizing the Company to repurchase shares of its Class A common stock from its employees, directors and officers, subject to certain conditions and restrictions. In 2010, the Company repurchased 117,505 shares of Class A common stock at $11.00 per share from thirteen employees (including the Executive Vice President, Chief Financial Officer and Chief Operating Officer, the Executive Vice President — Operations and the Vice President — Reservoir Engineering). In 2009, the Company repurchased 114,000 shares of Class A common stock at $7.33-$7.50 per share from ten employees (including the Vice President — Reservoir Engineering and the Vice President — Geophysics and New Ventures). No director nor the Company's Chairman and Chief Executive Officer has ever participated in the Repurchase Program. The Company's Board of Directors terminated the Repurchase Program in April 2011, and the Company is no longer authorized to repurchase shares of Class A common stock from its employees, directors and officers. No shares were repurchased in 2011 prior to the termination of the Repurchase Program by the Board of Directors.

In October 2008, the Company's Board of Directors approved the adoption of the Employee Option Exercise Loan Program ("Loan Program"), authorizing the Company to establish a loan program with a financial institution to assist its employees, directors and officers in the exercise of their outstanding options to purchase shares of Class A common stock, subject to certain conditions and restrictions outlined in the Loan Program. As part of the Loan Program, the Company provides the financial institution with a guaranty of repayment of the loan and makes deposits of funds in certificates of deposit to secure its guaranty. Notwithstanding the guaranty, these loans are fully recourse obligations of each loan recipient, and each loan recipient agrees to indemnify and reimburse the Company in full for all liabilities incurred by the Company in the event of the recipient's default on the loan. Each loan recipient also pledges all shares purchased from the Company with the loan proceeds to further secure his or her obligations to the Company in return for its guaranty. No director nor the Company's Chairman and Chief Executive Officer has ever participated in the Loan Program.

As of December 31, 2011, the Company had secured the loans of eight employees (including the Executive Vice President, Chief Financial Officer and Chief Operating Officer, the Executive Vice President — Operations and the Vice President — Reservoir Engineering) pursuant to this Loan Program in the aggregate amount of $1,326,000. The Company considers the fair value of this aggregate guaranty to be minimal and has recorded no liability provision associated with this guaranty on its consolidated balance sheets in any reporting period presented. The Company's Board of Directors terminated the Loan Program in April 2011, and the Company is no longer authorized to provide financial guaranties for additional loans. No new loans were guaranteed in 2011 prior to the termination of the Loan Program by the Board of Directors. Subsequent to December 31, 2011, the Company terminated its guaranties of the loans for the

NOTE 8 — EMPLOYEE BENEFIT PLANS — Continued

three officers of the Company noted above (see Note 17). The Company continues to secure the loans of the other five employees in the aggregate amount of $266,000.

401(k) Plan

Effective July 3, 2003, the Company established a defined contribution retirement plan. All full-time Company employees are eligible to join the plan the first day of the calendar month immediately following their date of employment. Each Participant may contribute up to the maximum allowable under the Internal Revenue Code. Each year, the Company makes a contribution to the plan which equals 3% of the employee's annual compensation, referred to as the Employer's Safe Harbor Non-Elective Contribution. The Company's Safe Harbor match was $166,204, $159,995, and $140,543 in 2011, 2010 and 2009, respectively. In addition, each year, the Company may determine and make a discretionary matching contribution as well as additional contributions. The Company's discretionary matching contributions totaled $207,735, $197,504, and $167,456 in 2011, 2010 and 2009, respectively. The Company made no additional discretionary contributions in any reporting period presented.

NOTE 9 — COMMON STOCK

Dividends

At December 31, 2011 and 2010, the Company had issued two classes of common stock, Class A and Class B. The holders of the Class B shares are entitled to be paid cumulative dividends at a per share rate of $0.26-2/3 annually out of funds legally available for the payment of dividends. These dividends were accrued and paid quarterly. Dividends declared during 2011, 2010 and 2009 totaled $274,853 in each year. Dividends for the fourth quarter of 2011 were accrued and paid in January 2012. Dividends for the fourth quarter of 2010 and 2009 were accrued and paid in January 2011 and 2010, respectively. As of December 31, 2011, the Company has not paid any dividends to holders of the Class A shares. In February 2012, upon the consummation of the Company's Initial Public Offering, the Class B shares were converted to Class A shares, which are now referred to as common stock (see Note 17).

Stock Offerings, Retirement and Issuances

Subsequent to December 31, 2011, the Company issued 12,209,167 shares of its common stock at $12.00 per share pursuant to its Initial Public Offering (see Note 17). In connection with this offering, the Company incurred $1,660,439 in legal, accounting and other fees during the year ended December 31, 2011, which were recorded as cost to issue equity in the Consolidated Statements of Shareholders' Equity.

In October 2010, the Board of Directors approved and authorized the private offering and sale of additional shares of the Company's Class A common stock at $11.00 per share in the period from October 2010 through January 2011. As of December 31, 2010, the Company sold 1,868,427 shares and received net proceeds of $20,536,167. In January 2011, the Company sold an additional 53,772 shares as part of this offering and received net proceeds of $584,918. The Company also sold 11,000 shares of Class A common stock at $9.00 per share to an accredited investor and received gross and net proceeds of $99,000 in May 2010.

NOTE 9 — COMMON STOCK — Continued

In February 2009, one of the Company's largest shareholders at the time, Gandhara Capital (Gandhara), a large international hedge fund, notified the Company of its need to sell its entire holdings of the Company's Class A common stock totaling 5,422,713 shares due to its plan for liquidation. The Board of Directors unanimously authorized the repurchase of all of Gandhara's outstanding shares at $5.00 per share, and Gandhara accepted this offer. In April 2009, the Company repurchased 5,422,713 shares of its Class A common stock from Gandhara for $27,113,565. These shares were effectively retired by the Company; however, this share repurchase and effective retirement did not reduce the 80,000,000 total shares of Class A common stock authorized for issue by the Company.

Following the repurchase of these shares from Gandhara, the Board of Directors approved and authorized the Company's May 2009 private offering in which the Company sold 4,950,694 shares of Class A common stock and received net proceeds of $27,982,569. In addition to this offering, the Company sold 23,500 shares of Class A common stock to two accredited shareholders and received net proceeds of $176,250 during 2009.

Treasury Stock

During 2010, the Company issued 6,000 shares of Class A common stock valued at $7.50-$9.00 per share from treasury stock. The Company also purchased 1,117,505 shares of Class A common stock for $9.00-$11.00 per share. These purchases included 1,000,000 shares of Class A common stock purchased from five shareholders, all advised by Wellington Management Company, in April 2010 at $9.00 per share, for a total of $9,000,000.

During 2009, the Company issued 652,126 shares of Class A common stock valued at $5.00-$7.50 per share from treasury stock. The Company also purchased 679,923 shares of Class A common stock from certain shareholders at $5.00-$7.50 per share.

NOTE 10 — DERIVATIVE FINANCIAL INSTRUMENTS

From time to time, the Company uses derivative financial instruments to mitigate its exposure to commodity price risk associated with oil and natural gas prices. These instruments consist of put and call options in the form of costless collars. The Company records derivative financial instruments on its balance sheet as either an asset or a liability measured at fair value. The Company has elected not to apply hedge accounting for its existing derivative financial instruments. As a result, the Company recognizes the change in derivative fair value between reporting periods currently in its consolidated statement of operations as an unrealized gain or loss. The fair value of the Company's derivative financial instruments is determined using purchase and sale information available for similarly traded securities. The Company has evaluated the credit standing of its single counterparty, Comerica Bank, in determining the fair value of these derivative financial instruments.

In November and December 2011, the Company entered into various costless collar contracts to mitigate its exposure to fluctuations in oil prices for the first time, each with an established price floor and ceiling. For each calculation period, the specified price for determining the realized gain or loss pursuant to

NOTE 10 — DERIVATIVE FINANCIAL INSTRUMENTS — Continued

any of these transactions is the arithmetic average of the settlement prices for the NYMEX West Texas Intermediate oil futures contract for the first nearby month corresponding to the calculation period's calendar month. When the settlement price is below the price floor established by these collars, the Company receives from Comerica Bank, as counterparty, an amount equal to the difference between the settlement price and the price floor multiplied by the contract oil volume. When the settlement price is above the price ceiling established by these collars, the Company pays to Comerica, as counterparty, an amount equal to the difference between the settlement price and the price ceiling multiplied by the contract oil volume.

During 2011, 2010 and 2009, the Company entered into various costless collar transactions for natural gas, each with an established price floor and ceiling. For each calculation period, the specified price for determining the realized gain or loss to the Company pursuant to any of these transactions is the settlement price for the NYMEX Henry Hub natural gas futures contract for the delivery month corresponding to the calculation period's calendar month for the last day of that contract period. When the settlement price is below the price floor established by these collars, the Company receives from Comerica Bank, as counterparty, an amount equal to the difference between the settlement price and the price floor multiplied by the contract natural gas volume. When the settlement price is above the price ceiling established by these collars, the Company pays to Comerica, as counterparty, an amount equal to the difference between the settlement price and the price ceiling multiplied by the contract natural gas volume.

At December 31, 2011, the Company had three costless collar contracts open and in place to mitigate its exposure to natural gas price volatility and three costless collar contracts open and in place to mitigate its exposure to oil price volatility, each with a specific term (calculation period), notional quantity (volume hedged) and price floor and ceiling. Each contract is set to expire at varying times during 2012 and 2013.

The following is a summary of the Company's open costless collar contracts for oil and natural gas at December 31, 2011.

Commodity	Calculation Period	Notional Quantity (Bbls/month)	Price Floor ($/Bbl)	Price Ceiling ($/Bbl)	Fair Value of Asset (Liability)
Oil	12/01/2011 - 12/31/2012	20,000	90.00	104.20	$ (219,283)
Oil	01/01/2012 - 12/31/2012	10,000	90.00	108.00	48,031
Oil	01/01/2013 - 12/31/2013	20,000	85.00	102.25	(382,848)
Total Oil					(554,100)

Commodity	Calculation Period	Notional Quantity (MMBtu/month)	Price Floor ($/MMBtu)	Price Ceiling ($/MMBtu)	Fair Value of Asset
Natural Gas	07/01/2011 - 12/31/2012	300,000	4.50	5.60	4,690,238
Natural Gas	07/01/2011 - 07/31/2013	150,000	4.50	5.75	3,196,466
Natural Gas	01/01/2012 - 12/31/2012	150,000	4.25	6.17	1,949,330
Total Natural Gas					9,836,034
Total open costless collar contracts					$9,281,934

NOTE 10 — DERIVATIVE FINANCIAL INSTRUMENTS — Continued

The following table summarizes the location and aggregate fair value of all derivative financial instruments recorded in the consolidated balance sheets for the periods presented. These derivative financial instruments are not designated as hedging instruments.

Type of Instrument	Location in Balance Sheet	December 31, 2011	December 31, 2010
Derivative Instrument			
Oil	Current liabilities: Derivative instruments	$ 171,252	$ –
Oil	Long-term liabilities: Derivative instruments	382,848	–
Natural Gas	Current assets: Derivative instruments	8,988,767	4,144,411
Natural Gas	Other assets: Derivative instruments	847,267	–
Total		$9,281,934	$4,144,411

The following table summarizes the location and aggregate fair value of all derivative financial instruments recorded in the consolidated statements of operations for the periods presented. These derivative financial instruments are not designated as hedging instruments.

Type of Instrument	Location in Statement of Operations	Year ended December 31, 2011	2010	2009
Derivative Instrument				
Natural Gas	Revenues: Realized gain on derivatives	$ 7,106,260	$5,299,380	$ 7,625,120
Realized gain on derivatives		7,106,260	5,299,380	7,625,120
Oil	Revenues: Unrealized loss on derivatives	(554,100)	–	–
Natural Gas	Revenues: Unrealized gain (loss) on derivatives	5,691,622	3,138,726	(2,374,638)
Unrealized gain (loss) on derivatives		5,137,522	3,138,726	(2,374,638)
Total		$12,243,782	$8,438,106	$ 5,250,482

NOTE 11 — FAIR VALUE MEASUREMENTS

The Company measures and reports certain financial and non-financial assets and liabilities on a fair value basis. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). Fair value measurements are classified and disclosed in one of the following categories.

Level 1 Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. Active markets are considered to be those in which transactions for the assets or liabilities occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 Quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability. This category includes those derivative instruments that are valued using observable market data. Substantially all of these inputs are observable in the marketplace throughout the full term of the derivative instrument, can be derived from observable data or supported by observable levels at which transactions are executed in the marketplace.

Level 3 Unobservable inputs that are not corroborated by market data. This category is comprised of financial and non-financial assets and liabilities whose fair value is estimated based on internally developed models or methodologies using significant inputs that are generally less readily observable from objective sources.

Financial and non-financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. The assessment of the significance of a particular input to the fair value measurement requires judgment, which may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

The following tables summarize the valuation of the Company's financial assets and liabilities that were accounted for at fair value on a recurring basis in accordance with the classifications provided above as of December 31, 2011 and 2010.

Description	Fair Value Measurements at December 31, 2011 using			
	Level 1	Level 2	Level 3	Total
Assets				
Certificates of deposit	$–	$ 1,335,000	$–	$ 1,335,000
Oil and natural gas derivatives	–	9,836,034	–	9,836,034
Liabilities				
Oil and natural gas derivatives	–	(554,100)	–	(554,100)
Total	$–	$10,616,934	$–	$10,616,934

Description	Fair Value Measurements at December 31, 2010 using			
	Level 1	Level 2	Level 3	Total
Assets				
Certificates of deposit	$–	$ 2,349,313	$–	$ 2,349,313
Natural gas derivatives	–	4,144,411	–	4,144,411
Total	$–	$ 6,493,724	$–	$ 6,493,724

NOTE 11 — FAIR VALUE MEASUREMENTS — Continued

The Company's accounting policies for certificates of deposit and derivative financial instruments are discussed in Note 2; additional disclosures related to derivative financial instruments are provided in Note 10. For purposes of fair value measurement, the Company determined that certificates of deposit and derivative financial instruments (e.g., oil and natural gas derivatives) should be classified as Level 2.

The Company accounts for additions to asset retirement obligations and lease and well equipment inventory at fair value on a non-recurring basis. The following tables summarize the valuation of the Company's assets and liabilities that were accounted for at fair value on a non-recurring basis as of December 31, 2011 and 2010.

Description	Fair Value Measurements at December 31, 2011 using			
	Level 1	Level 2	Level 3	Total
Assets (Liabilities)				
Asset retirement obligations	$–	$–	$ (186,873)	$ (186,873)
Lease and well equipment inventory	–	–	1,343,416	1,343,416
Total	$–	$–	$1,156,543	$1,156,543

Description	Fair Value Measurements at December 31, 2010 using			
	Level 1	Level 2	Level 3	Total
Assets (Liabilities)				
Asset retirement obligations	$–	$–	$ (847,845)	$ (847,845)
Lease and well equipment inventory	–	–	442,500	442,500
Total	$–	$–	$ (405,345)	$ (405,345)

The Company's accounting policies for asset retirement obligations are discussed in Note 2; reconciliations of the Company's asset retirement obligations are provided in Note 4 for the periods presented. For purposes of fair value measurement, the Company determined that the additions to asset retirement obligations should be classified as Level 3. The Company recorded additions to asset retirement obligations of $186,873 and $847,845 in 2011 and 2010, respectively.

The Company's accounting policies for lease and well equipment inventory are discussed in Note 2. For purposes of fair value measurement, the Company determined that lease and well equipment inventory should be classified as Level 3. The Company recorded an impairment to some of its equipment held in inventory, consisting primarily of drilling rig parts, of $17,500 and $50,000 in 2011 and 2010, respectively. The Company recorded an impairment to some of its equipment held in inventory, consisting primarily of pipe and other equipment, of $22,276 in 2011; no impairment to this equipment was recorded in 2010. The Company periodically obtains estimates of the market value of its equipment held in inventory from an independent third-party contractor or seller of similar equipment and uses these estimates as a basis for its measurement of the fair value of this equipment.

NOTE 12 — COMMITMENTS AND CONTINGENCIES

Office Lease

The Company's corporate headquarters are located in 28,743 square feet of office space at One Lincoln Centre, 5400 LBJ Freeway, Suite 1500, Dallas, Texas. The office lease commencement date was September 25, 2003 with an expiration date of June 30, 2011. In April 2011, the Company agreed to a restated third amendment to its office lease agreement, in which the office space was increased to 28,743 square feet and the term of the lease was extended from July 1, 2011 to June 30, 2022. The effective base rent over the term of the new lease extension is $19.75 per square foot per year. The base rate escalates several times during the course of the lease, specifically in July 2015, July 2017, July 2019 and July 2020.

The following is a schedule of future minimum lease payments required under the office lease agreement as of December 31, 2011.

Year ending December 31,	Amount
2012	$ 287,430
2013	574,860
2014	574,860
2015	589,232
2016	603,603
Thereafter	3,612,995
Total	$6,242,980

Rent expense, including fees for operating expenses and consumption of electricity, was $474,923, $386,092 and $417,371 for 2011, 2010 and 2009, respectively.

Other Commitments

At December 31, 2011, the Company had entered into two drilling rig contracts to explore and develop its Eagle Ford acreage in south Texas. The two rigs began drilling on the Company's acreage in September and October 2011, respectively. Both contracts are for a term of six months. Should the Company elect to terminate one or both contracts and if the drilling contractor were unable to secure work for one or both rigs or if the drilling contractor were unable to secure work for one or both rigs at the same daily rates being charged to the Company prior to the end of their respective contract terms, the Company would incur termination obligations. The Company's maximum outstanding aggregate termination obligations under these contracts were approximately $2.7 million at December 31, 2011.

At December 31, 2011, the Company had outstanding commitments to participate in the drilling and completion of various non-operated wells in the Haynesville shale. The Company's working interests in these wells are small, and most of these wells were in progress at December 31, 2011. If all of these wells are drilled and completed, the Company's minimum outstanding aggregate commitments at December 31, 2011 for its participation in these non-operated Haynesville wells were approximately $5.1 million, and the Company expects these costs to be incurred in the next 12 months.

NOTE 12 — COMMITMENTS AND CONTINGENCIES — Continued

In June 2011, the Company awarded bonuses to certain of its current employees, but not including any of its executive officers, in the aggregate amount of $1,240,000. These bonuses will be payable in a lump sum to each of the employees in June 2014, provided each continues to remain an employee in good standing with Company at that time.

Legal Proceedings

The Company is a defendant in several lawsuits encountered in the ordinary course of its business, none of which, in the opinion of management, will have a material adverse impact on the Company's financial position, results of operations or cash flows.

General Federal and State Regulations

Oil and natural gas exploration, production and related operations are subject to extensive federal and state laws, rules and regulations. Failure to comply with these laws, rules and regulations can result in substantial penalties. The regulatory burden on the oil and natural gas industry increases the cost of doing business and affects profitability. The Company believes that it is in compliance with currently applicable state and federal regulations. Because these rules and regulations are frequently amended or reinterpreted, however, the Company is unable to predict the future cost or impact of complying with these regulations.

Environmental Regulations

The exploration, development and production of oil and natural gas, including the operation of salt water injection and disposal wells, are subject to various federal, state and local environmental laws and regulations. These laws and regulations can increase the costs of planning, designing, installing, and operating oil and natural gas wells. The Company's activities are subject to a variety of environmental laws and regulations, including but not limited to the Oil Pollution Act of 1990, or OPA, the Clean Water Act, or CWA, the Comprehensive Environmental Response, Compensation and Liability Act, or CERCLA, the Resource Conservation and Recovery Act, or RCRA, the Clean Air Act, or CAA, the Safe Drinking Water Act, or SDWA, and the Occupational Safety and Health Act, or OSHA, as well as comparable state statutes and regulations. The Company is also subject to regulations governing the handling, transportation, storage and disposal of waste generated by its activities and of naturally occurring radioactive materials, or NORM, that may result from its oil and natural gas operations. Civil and criminal fines and penalties may be imposed for noncompliance with these environmental laws and regulations. Additionally, these laws and regulations require the acquisition of permits or other governmental authorizations before undertaking some activities, limit or prohibit other activities because of protected wetlands, areas or species, and require investigation and cleanup of pollution. The Company has no outstanding material environmental remediation liabilities and believes that it is in compliance with currently applicable environmental laws and regulations and that these laws and regulations will not have a material adverse impact on the financial position, results of operations or cash flows of the Company.

Changes in environmental laws and regulations occur frequently, however, and any changes that result in more stringent and costly waste handling, storage, transport, disposal or cleanup requirements could, and in all likelihood would, materially adversely affect the Company's financial position, results of operations

NOTE 12 — COMMITMENTS AND CONTINGENCIES — Continued

and cash flows, as well as those of the oil and natural gas industry in general. Because these rules and regulations are frequently amended or reinterpreted, the Company is unable to predict the future cost or impact of complying with these regulations. For instance, recent scientific studies have suggested that emissions of certain gases, commonly referred to as "greenhouse gases," and including carbon dioxide and methane, may be contributing to the warming of the Earth's atmosphere. As a result, there have been attempts to pass comprehensive greenhouse gas legislation. To date, such legislation has not been enacted. Any future federal or state laws or implementing regulations that may be adopted to address greenhouse gas emissions could, and in all likelihood would, require the Company to incur increased operating costs adversely affecting its financial position, results of operations and cash flows.

The Company's activities involve the use of hydraulic fracturing. Recently, there has been increasing regulatory scrutiny of hydraulic fracturing, which is generally exempted from regulation as underground injection at the federal level. At the federal level and in some states, there have been efforts to place additional regulatory burdens on hydraulic fracturing activities. In addition, certain bills have been introduced in the Senate and the House of Representatives that, if adopted, could increase the possibility of litigation and establish an additional level of regulation at the federal level that could lead to operational delays or increased operating costs and could, and in all likelihood, would, result in additional regulatory burdens, making it more difficult to perform hydraulic fracturing operations and increasing the Company's costs of compliance. At the state level, Wyoming and Texas, for example, have enacted requirements for the disclosure of the composition of the fluids used in hydraulic fracturing. On June 17, 2011, Texas signed into law a mandate for public disclosure of the chemicals that operators use during hydraulic fracturing in Texas. The law went into effect September 1, 2011. State regulators have until 2013 to complete implementing rules. In addition, at least a few local governments in Texas have imposed temporary moratoria on drilling permits within city limits so that local ordinances may be reviewed to assess their adequacy to address hydraulic fracturing activities. Additional burdens on hydraulic fracturing, such as reporting requirements or permitting requirements for hydraulic fracturing activities, could, and in all likelihood would, result in additional expense and delay the Company's operations adversely affecting its financial position, results of operations and cash flows.

Oil and natural gas exploration and production, operations and other activities have been conducted at some of the Company's properties by previous owners and operators. Materials from these operations remain on some of the properties, and, in some instances, require remediation. In addition, the Company occasionally must agree to indemnify sellers of producing properties the Company acquires against some or all of the liability for environmental claims associated with these properties. While the Company does not believe that the costs it incurs for compliance with environmental regulations and remediating previously or currently owned or operated properties will be material, the Company cannot provide assurances that these costs will not result in material expenditures that adversely affect its financial position, results of operations and cash flows.

The Company maintains insurance against some, but not all, potential risks and losses associated with the oil and natural gas industry and operations. The Company does not carry business interruption insurance. For some risks, the Company may not obtain insurance if it believes the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks

NOTE 12 — COMMITMENTS AND CONTINGENCIES — Continued

generally are not fully insurable. If a significant accident or other event occurs and is not fully covered by insurance, it could, and in all likelihood would, materially adversely affect the Company's financial position, results of operations and cash flows.

NOTE 13 — MAJOR CUSTOMERS

For the year ended December 31, 2011, the Company had three significant purchasers that each accounted for more than 10% of its total oil and natural gas revenues: Sequent Energy Management (24%), Chesapeake Operating, Inc. (21%) and Eastex Crude Company (15%). For the year ended December 31, 2010, the Company had three significant purchasers that each accounted for more than 10% of its total oil and natural gas revenues: Chesapeake Operating, Inc. (42%), Regency Gas Services LP (17%) and Petrohawk Energy Corporation (11%). For the year ended December 31, 2009, the Company had three significant purchasers that each accounted for more than 10% of its total oil and natural gas revenues: Chesapeake Operating, Inc. (32%), Regency Gas Services LP (25%) and J-W Operating Company (17%). Due to the nature of the markets for oil and natural gas, the Company does not believe that the loss of any one purchaser would have a material adverse impact on the Company's financial position, results of operations or cash flows for any significant period of time.

At December 31, 2011, the Company had two industry partners, Goodrich Petroleum Corporation, LLC and Alliance Capital Real Estate, Inc. that accounted for 77% and 17% of its accounts receivable, respectively. At December 31, 2010, the Company had one industry partner, Goodrich Petroleum Corporation, LLC, that accounted for approximately 93%, of its accounts receivable.

NOTE 14 — SUPPLEMENTAL DISCLOSURES

Accrued Liabilities

The following table summarizes the Company's current accrued liabilities at December 31, 2011 and 2010.

	December 31,	
	2011	2010
Accrued evaluated and unproved and unevaluated property costs	$18,184,818	$12,119,475
Accrued support equipment and facilities costs	215,517	40,145
Accrued cost to issue equity	331,818	359,175
Accrued stock-based compensation	2,859,527	1,095,014
Accrued lease operating expenses	575,318	428,481
Accrued asset retirement obligations	334,500	131,166
Other	2,937,395	616,256
Total accrued liabilities	$25,438,893	$14,789,712

NOTE 14 — SUPPLEMENTAL DISCLOSURES — Continued

Supplemental Cash Flow Information

The following table provides supplemental disclosures of cash flow information for the years ended December 31, 2011, 2010 and 2009.

	Year ended December 31,		
	2011	2010	2009
Cash paid (refunded) for income taxes	$ 60	$ (2,155,517)	$(1,235,672)
Cash paid for interest expense, net of amounts capitalized	633,562	–	–
Asset retirement obligations related to mineral properties	487,529	862,238	642,836
Asset retirement obligations related to support equipment and facilities	11,531	126,386	8,155
Increase (decrease) in liabilities for oil and natural gas properties capital expenditures	1,863,715	15,530,871	(2,470,798)
Increase in liabilities for support equipment and facilities	175,372	39,657	–
Issuance of treasury stock for Board and advisor services	–	47,250	29,375
Issuance of stock for Board and advisor services	230,400	–	–
(Decrease) increase in liabilities for accrued cost to issue equity	(27,357)	359,174	–
Stock based compensation expense recognized as liability	2,102,271	164,188	–
Transfer of inventory to oil and natural gas properties	96,164	353,395	–

NOTE 15 — TRANSACTIONS WITH RELATED PARTIES

In January 2007, the Company entered into a joint venture with Marlan Downey and Julie Downey Garvin of Roxanna Oil Company ("Roxanna") to assemble acreage for and to market a new gas shale prospect in southwest Wyoming, northeast Utah and southeast Idaho. Mr. Downey is a special advisor to the Company's Board of Directors and a shareholder in the Company. Ms. Garvin is President of Roxanna, which is also a shareholder in Matador. Mr. Downey and Ms. Garvin developed the prospect concept independently and sought the Company's expertise in assembling a large acreage position across the prospect. At December 31, 2011, the Company has assembled over 140,000 acres across the prospect at a total cost of approximately $9,700,000. The Company actively marketed this prospect in conjunction with Mr. Downey and Ms. Garvin. In May 2010, the Company, Roxanna and its subsidiary, Roxanna Rocky Mountains, LLC, entered into participation and joint operating agreements with an industry partner for the joint exploration and development of this opportunity. Under these agreements, Roxanna Rocky Mountains, LLC reserves a 2.5% overriding royalty interest in the leases and has the opportunity to earn up to a 10% working interest in all wells drilled. The industry partner has a 50% working interest in the project, and the Company retains a working interest equal to the difference between 50% and the working interest participation elected by Roxanna Rocky Mountains, LLC. The Company, as operator, drilled the initial test well for this prospect located in Lincoln County, Wyoming during 2011. This well was awaiting completion at December 31, 2011.

NOTE 16 — SUPPLEMENTAL OIL AND NATURAL GAS DISCLOSURES (Unaudited)

Costs Incurred

The following table summarizes costs incurred and capitalized by the Company in the acquisition, exploration, and development of oil and natural gas properties for the years ended December 31, 2011, 2010 and 2009.

	Year ended December 31,		
	2011	2010	2009
Property acquisition costs			
Proved	$ –	$ –	$ –
Unproved and unevaluated	41,496,929	100,730,019	24,803,480
Exploration costs	108,662,417	60,718,511	21,386,885
Development costs	12,511,018	14,348,040	6,225,511
Total costs incurred	$162,670,364	$175,796,570	$52,415,876

Property acquisition costs are costs incurred to purchase, lease or otherwise acquire oil and natural gas properties, including both unproved and unevaluated leasehold and purchases of reserves in place. For the years ended December 31, 2011, 2010 and 2009, respectively, essentially all of the Company's property acquisition costs resulted from the acquisition of unproved and unevaluated leasehold positions.

Exploration costs are costs incurred in identifying areas of these oil and gas properties that may warrant further examination and in examining specific areas that are considered to have prospects of containing oil and natural gas, including costs of drilling exploratory wells, geological and geophysical costs, and costs of carrying and retaining unproved and unevaluated properties. Exploration costs may be incurred before or after acquiring the related oil and natural gas properties.

Development costs are costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing oil and natural gas. Development costs include the costs of preparing well locations for drilling, drilling and equipping development wells and related service wells (e.g., salt water disposal wells) and acquiring, constructing and installing production facilities.

Costs incurred also include new asset retirement obligations established, as well as changes to asset retirement obligations resulting from revisions in cost estimates or abandonment dates. Asset retirement obligations included in the table above were $499,060, $988,624 and $650,991 for the years ended December 31, 2011, 2010 and 2009, respectively. Capitalized general and administrative expenses that are directly related to acquisition, exploration and development activities are also included in the table above. The Company capitalized $2,020,486, $1,604,682, and $1,642,868 of these internal costs in 2011, 2010 and 2009, respectively. Capitalized interest expense for qualifying projects are also included in the table above. The Company capitalized $1,278,383 of its interest expense for the year ended December 31, 2011. The Company recorded only $3,235 in interest expense for the year ended December 31, 2010 and had no outstanding borrowings in 2009. As a result, the Company capitalized no interest expense for the years ended December 31, 2010 and 2009.

NOTE 16 — SUPPLEMENTAL OIL AND NATURAL GAS DISCLOSURES (Unaudited) — Continued

Oil and Natural Gas Operating Results

The following table provides the results of operations from oil and gas producing activities, excluding corporate overhead and interest costs, for the years ended December 31, 2011, 2010 and 2009.

	Year ended December 31,		
	2011	2010	2009
Oil and natural gas revenues	$ 66,999,826	$34,041,607	$ 19,038,514
Production taxes and marketing expenses	6,277,860	1,981,550	1,077,145
Lease operating expenses	7,244,339	5,284,362	4,725,022
Depletion, depreciation and amortization	31,619,443	15,423,044	10,510,769
Accretion of asset retirement obligations	208,547	154,756	137,347
Full-cost ceiling impairment	35,673,098	–	25,243,738
Net operating income (loss)	(14,023,461)	11,197,895	(22,655,507)
Income tax provision (benefit)	(5,018,997)	3,982,834	(8,055,619)
Results of oil and natural gas operations	$ (9,004,464)	$ 7,215,061	$(14,599,888)
Depletion, depreciation and amortization per Mcfe	$ 2.05	$ 1.79	$ 2.10

Oil and Natural Gas Reserves

Proved reserves are estimated quantities of oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs using existing economic and operating conditions. Estimating oil and natural gas reserves is complex and is not exact because of the numerous uncertainties inherent in the process. The process relies on interpretations of available geological, geophysical, petrophysical, engineering and production data. The extent, quality and reliability of both the data and the associated interpretations of that data can vary. The process also requires certain economic assumptions, including, but not limited to, oil and natural gas prices, drilling and operating expenses, capital expenditures and taxes. Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas most likely will vary from the Company's estimates.

Oil and natural gas reserves are estimated using then-current operating and economic conditions, with no provision for price and cost escalations in future periods except by contractual arrangements. In January 2009, the SEC issued *The Modernization of Oil and Gas Reporting, Final Rule* and in January 2010, the FASB amended *Topic 932, Extractive Activities — Oil and Gas* to align with this rule. As a result, beginning December 31, 2009, the commodity prices used to estimate oil and natural gas reserves are based on unweighted, arithmetic averages of first-day-of-the-month oil and natural gas prices for the previous 12-month period. For the period January through December 2011, these average oil and natural gas prices were $92.71 per barrel and $4.118 per MMBtu (million British thermal units), respectively. For the period January through December 2010, these average oil and natural gas prices were $75.96 per barrel and $4.376 per MMBtu, respectively. For the period January through December 2009, these average oil and natural gas prices were $57.65 per barrel and $3.866 per MMBtu, respectively.

NOTE 16 — SUPPLEMENTAL OIL AND NATURAL GAS DISCLOSURES (Unaudited) — Continued

The Company's oil and natural gas reserves estimates are prepared by the Company's engineering staff in accordance with guidelines established by the SEC and then audited for their reasonableness and conformance with SEC guidelines by Netherland, Sewell & Associates, Inc., independent reservoir engineers, for the years ended December 31, 2011, 2010 and 2009.

The Company's net ownership in estimated quantities of proved oil and natural gas reserves and changes in net proved reserves are summarized as follows. All of the Company's oil and natural gas reserves are attributable to properties located in the United States. The estimated reserves shown below are for proved reserves only and do not include any value for unproved reserves classified as probable or possible reserves that might exist for these properties, nor do they include any consideration that could be attributed to interests in unevaluated acreage beyond those tracts for which reserves have been estimated. In the tables presented throughout this section, oil is converted to gas equivalent using the ratio of one barrel of oil, condensate or natural gas liquids to 6 Mcf (thousand standard cubic feet) of natural gas.

	Net Proved Reserves		
	Oil (MBbl)	Gas (MMcf)	Gas Equivalent (MMcfe)
Proved Developed and Proved Undeveloped Reserves			
Total at December 31, 2008	131	19,196	19,979
Revisions of prior estimates	(13)	(811)	(883)
Extensions and discoveries	15	50,367	50,454
Production	(30)	(4,823)	(5,002)
Total at December 31, 2009	103	63,929	64,548
Revisions of prior estimates	66	874	1,265
Extensions and discoveries	16	71,009	71,107
Production	(33)	(8,400)	(8,597)
Total at December 31, 2010	152	127,412	128,323
Revisions of prior estimates	51	(646)	(343)
Extensions and discoveries	3,745	58,164	80,636
Production	(154)	(14,512)	(15,437)
Total at December 31, 2011	3,794	170,418	193,179
Proved Developed Reserves			
December 31, 2008	131	19,196	19,979
December 31, 2009	103	25,369	25,988
December 31, 2010	152	43,143	44,054
December 31, 2011	1,419	56,547	65,061
Proved Undeveloped Reserves			
December 31, 2008	–	–	–
December 31, 2009	–	38,560	38,560
December 31, 2010	–	84,269	84,269
December 31, 2011	2,375	113,871	128,118

NOTE 16 — SUPPLEMENTAL OIL AND NATURAL GAS DISCLOSURES (Unaudited) — Continued

The following is a discussion of the changes in the Company's proved oil and natural gas reserves estimates for the years ended December 31, 2011, 2010 and 2009.

The Company's proved oil and natural gas reserves increased to 193.2 Bcfe at December 31, 2011 from 128.3 Bcfe at December 31, 2010. The Company increased its proved oil and natural gas reserves by 80.3 Bcfe and produced 15.4 Bcfe during the year ended December 31, 2011, resulting in a net gain of 64.9 Bcfe. A total of 80.6 Bcfe of the increase in proved oil and gas reserves was a result of extensions and discoveries during the year, all of which was attributable to drilling operations in the Eagle Ford shale play in south Texas and the Haynesville shale play in northwest Louisiana. The Company's oil and natural gas reserves decreased by 0.3 Bcfe during the year as a result of revisions to previous estimates, representing the net impact of small changes in prior estimates of proved reserves on a well-by-well basis. The Company's proved developed oil and natural gas reserves increased to 65.1 Bcfe at December 31, 2011 from 44.1 Bcfe at December 31, 2010, primarily due to proved developed reserves added as a result of drilling operations in the Eagle Ford and Haynesville shale plays. At December 31, 2011, the Company's proved reserves were made up of approximately 88% natural gas and 12% oil.

The Company's proved oil and natural gas reserves increased to 128.3 Bcfe at December 31, 2010 from 64.5 Bcfe at December 31, 2009. The Company increased its proved oil and natural gas reserves by 72.4 Bcfe and produced 8.6 Bcfe during the year ended December 31, 2010, resulting in a net gain of 63.8 Bcfe. A total of 71.1 Bcfe of the increase in proved oil and gas reserves was a result of extensions and discoveries during the year, almost all of which was attributable to drilling operations in the Haynesville shale play in northwest Louisiana. A total of 1.3 Bcfe of the increase in proved oil and natural gas reserves was attributable to revisions of previous estimates, representing the net impact of small changes in prior estimates of proved reserves on a well-by-well basis. The Company's proved developed oil and natural gas reserves increased to 44.1 Bcfe at December 31, 2010 from 26.0 Bcfe at December 31, 2009, primarily due to proved developed reserves added as a result of drilling operations in the Haynesville shale play. At December 31, 2010, the Company's proved reserves were made up of approximately 99% natural gas and 1% oil.

The Company's proved oil and natural gas reserves increased to 64.5 Bcfe at December 31, 2009 from 20.0 Bcfe at December 31, 2008. The Company increased its proved oil and natural gas reserves by 49.5 Bcfe and produced 5.0 Bcfe during the year ended December 31, 2009, resulting in a net gain of 44.5 Bcfe. The Company added 50.4 Bcfe in proved oil and natural gas reserves as a result of extensions and discoveries during the year, almost all of which was attributable to drilling operations in the Haynesville shale play in northwest Louisiana. The Company's oil and natural gas reserves decreased by 0.9 Bcfe during the year as a result of revisions to previous estimates, representing the net impact of small changes in prior estimates of proved reserves on a well-by-well basis. The Company's proved developed oil and natural gas reserves increased to 26.0 Bcfe at December 31, 2009 from 20.0 Bcfe at December 31, 2008, primarily due to proved developed reserves added as a result of drilling operations in the Haynesville shale play. At December 31, 2009, the Company's proved reserves were made up of approximately 99% natural gas and 1% oil.

NOTE 16 — SUPPLEMENTAL OIL AND NATURAL GAS DISCLOSURES (Unaudited) — Continued

Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Oil and Natural Gas Reserves

The standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves is not intended to provide an estimate of the replacement cost or fair market value of the Company's oil and natural gas properties. An estimate of fair market value would also take into account, among other things, the recovery of reserves not presently classified as proved, anticipated future changes in prices and costs, potential improvements in industry technology and operating practices, the risks inherent in reserves estimates and perhaps different discount rates.

As noted previously, for the period January through December 2011, average oil and natural gas prices were $92.71 per barrel and $4.118 per MMBtu (million British thermal units), respectively. For the period January through December 2010, average oil and natural gas prices were $75.96 per barrel and $4.376 per MMBtu, respectively. For the period January through December 2009, average oil and natural gas prices were $57.65 per barrel and $3.866 per MMBtu, respectively.

Future net cash flows were computed by applying these oil and natural gas prices, adjusted for all associated transportation costs, gravity and energy content, and regional price differentials, to year-end quantities of proved oil and natural gas reserves and accounting for any future production and development costs associated with producing these reserves; neither prices nor costs were escalated with time in these computations.

Future income taxes were computed by applying the statutory tax rate to the excess of future net cash flows relating to proved oil and natural gas reserves less the tax basis of the associated properties. Tax credits and net operating loss carryforwards available to the Company were also considered in the computation of future income taxes. Future net cash flows after income taxes were discounted using a 10% annual discount rate to derive the standardized measure of discounted future net cash flows.

The following table presents the standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves (in thousands) for the years ended December 31, 2011, 2010 and 2009.

	Year ended December 31,		
	2011	2010	2009
Future cash inflows	$ 924,796	$ 470,386	$219,410
Future production costs	(194,538)	(107,183)	(55,513)
Future development costs	(235,469)	(107,277)	(35,788)
Future income tax expense	(83,840)	(35,352)	(15,805)
Future net cash flows	410,949	220,574	112,304
10% annual discount for estimated timing of cash flows	(195,476)	(109,497)	(47,243)
Standardized measure of discounted future net cash flows	$ 215,473	$ 111,077	$ 65,061

NOTE 16 — SUPPLEMENTAL OIL AND NATURAL GAS DISCLOSURES (Unaudited) — Continued

The following table summarizes the changes in the standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves (in thousands) for the years ended December 31, 2011, 2010 and 2009.

	Year ended December 31,		
	2011	2010	2009
Balance, beginning of period	$111,077	$ 65,061	$ 43,254
Net change in sales and transfer prices and in production (lifting) costs related to future production	53,903	7,632	(10,433)
Changes in estimated future development costs	(64,958)	(36,821)	(17,502)
Sales and transfers of oil and gas produced during the period	(53,478)	(26,776)	(13,236)
Net change due to extensions and discoveries	182,282	94,265	70,361
Net change due to revisions in estimates of reserves quantities	(653)	1,676	(1,232)
Previously estimated development costs incurred during the period	1,023	7,125	(590)
Accretion of discount	11,987	7,036	4,317
Other	(1,335)	1,035	(3,068)
Net change in income taxes	(24,375)	(9,156)	(6,810)
Standardized measure of discounted future net cash flows	$215,473	$111,077	$ 65,061

NOTE 17 — SUBSEQUENT EVENTS

On August 12, 2011, the Company filed a Form S-1 Registration Statement under the Securities Act of 1933 to commence the initial public offering of its common stock (the "Initial Public Offering"). The Company's Registration Statement (File 333-176263), as amended, was declared effective by the SEC on February 1, 2012. The underwriters for the Company's Initial Public Offering were RBC Capital Markets, LLC; Citigroup Global Markets, Inc.; Jefferies & Company, Inc.; Howard Weil Incorporated; Stifel, Nicolaus & Company, Incorporated; Simmons & Company International; Stephens Inc.; and Comerica Securities, Inc. On February 2, 2012, shares of the Company's common stock began trading on the New York Stock Exchange under the symbol "MTDR" at an initial offering price of $12.00 per share.

Pursuant to its Prospectus dated February 1, 2012, the Company and the selling shareholders offered 13,333,334 shares of the Company's common stock for sale. The Company offered 11,666,667 shares of its common stock, and the selling shareholders offered 1,666,667 shares. On February 7, 2012, the Company closed the Initial Public Offering and issued 11,666,667 shares of its common stock pursuant to the Initial Public Offering.

The Company and the selling shareholders granted the underwriters the right to purchase up to an additional 2,000,000 shares of the Company's common stock at the initial offering price of $12.00 per share, less the underwriters' discounts and commissions, for a period of 30 days following the Initial Public Offering to cover over-allotments, with the Company offering 700,000 shares and the selling shareholders offering 1,300,000. On March 2, 2012, the underwriters exercised their option to purchase an additional

NOTE 17 — SUBSEQUENT EVENTS — Continued

1,550,000 shares, including the purchase of 542,500 shares from the Company and the purchase of 1,007,500 shares from the selling shareholders. On March 7, 2012, the Company closed this transaction and issued 542,500 shares of its common stock pursuant to the underwriters' exercise of the over-allotment.

Pursuant to the Initial Public Offering and the over-allotment, the Company issued a total of 12,209,167 shares of its common stock at $12.00 per share and received estimated net proceeds of approximately $133,600,000 after deducting the underwriters' discounts and commissions and the estimated legal, accounting and other fees associated with the offering. The Company did not receive any proceeds from the sale of shares of its common stock by the selling shareholders. On February 8, 2012, the Company used the net proceeds of the offering to repay the $123,000,000 in borrowings then outstanding under its Credit Agreement in full. The Company used the remaining net proceeds of the offering to fund a portion of its 2012 capital expenditures.

Concurrent with the completion of the Initial Public Offering, all 1,030,700 shares of the Company's Class B common stock were converted to Class A common stock on a one-for-one basis. In addition, in February 2012, the Company issued an additional 295,500 shares of its Class A common stock pursuant to the exercise of stock options and received net proceeds of $2,659,500. The Class A common stock is now referred to as the common stock.

Effective February 1, 2012, the Company granted an employee the option to purchase 150,000 shares of its common stock at an exercise price of $12.00 per share. These shares vest over approximately a three-year period, with 50,000 shares being fully vested on December 31, 2012 and an incremental 50,000 shares being vested on each of December 31, 2013 and 2014. The option expires on January 31, 2022.

Following the repayment of the outstanding debt under its Credit Agreement, the Company's borrowing base was reduced to $100,000,000. On February 28, 2012, the borrowing base under the Company's Credit Agreement was increased to $125,000,000 pursuant to a special borrowing base redetermination made by the lenders at the Company's request.

In January 2012, the Company borrowed $10,000,000 under its Credit Agreement, bringing its then-outstanding borrowings to a total of $123,000,000. These outstanding borrowings were repaid in full on February 8, 2012. On March 19, 2012, the Company borrowed $15,000,000 under its Credit Agreement. At March 30, 2012, the Company had $15,000,000 of outstanding borrowings under its Credit Agreement and $1,262,934 in letters of credit issued pursuant to the Credit Agreement. At March 30, 2012, all borrowings under the Credit Agreement bear interest at approximately 2.0% per annum.

Effective January 1, 2012, the Board of Directors adopted the 2012 Long-Term Incentive Plan (the "2012 Incentive Plan"). The 2012 Incentive Plan provides for a maximum of 4,000,000 shares of common stock in the aggregate that may be issued by the Company pursuant to grants of stock options, restricted stock, stock appreciation rights, restricted stock units or other performance awards. The persons eligible to receive awards under the 2012 Incentive Plan include employees, contractors and outside directors of the Company. The primary purpose of the 2012 Incentive Plan is to attract and retain key employees, key contractors and outside directors of the Company. With the adoption of the 2012 Incentive Plan, the

NOTE 17 — SUBSEQUENT EVENTS — Continued

Company does not plan to make any future awards under the 2003 Stock and Incentive Plan, but the 2003 Stock and Incentive Plan will remain in place until all awards outstanding under that plan have been settled (see Note 8).

In January 2012, the Company terminated its guaranties and the associated pledge of certificates of deposit related to the loans of three officers of the Company under the Employee Option Exercise Loan Program (see Note 8). The Company continues to secure the loans of five employees in the aggregate amount of $266,000.

During the first quarter of 2012, the Company entered into several additional costless collar transactions to mitigate its risks associated with fluctuations in oil prices. The following table summarizes these contracts.

Commodity	Calculation Period	Notional Quantity (Bbls/month)	Price Floor ($/Bbl)	Price Ceiling ($/Bbl)
Oil	01/01/2012 - 12/31/2012	10,000	90.00	109.50
Oil	02/01/2012 - 06/30/2012	20,000	90.00	113.75
Oil	04/01/2012 - 12/31/2012	20,000	90.00	111.00
Oil	04/01/2012 - 03/31/2013	20,000	90.00	110.00
Oil	07/01/2012 - 12/31/2012	20,000	90.00	111.90
Oil	07/01/2012 - 12/31/2012	20,000	95.00	116.00
Oil	01/01/2013 - 12/31/2013	20,000	90.00	115.00
Oil	01/01/2013 - 12-31/2013	20,000	85.00	110.40
Oil	01/01/2013 - 12/31/2013	20,000	85.00	108.80
Oil	01/01/2013 - 06/30/2014	8,000	90.00	114.00
Oil	01/01/2013 - 06/30/2014	12,000	90.00	115.50

During the first quarter of 2012, the Company extended one of its drilling rig contracts in south Texas for an additional nine months. The Company terminated its second contract with no termination penalty and entered into a new contract for a higher performance rig with the same drilling rig contractor for a period of one year. Drilling operations under these two contracts began in early March 2012. Should the Company elect to terminate one or both contracts and if the drilling contractor were unable to secure work for one or both rigs or if the drilling contractor were unable to secure work for one or both rigs at the same daily rate being charged to the Company prior to the end of their respective terms, the Company would incur termination obligations. The Company's maximum outstanding aggregate termination obligations under these contracts were approximately $9.8 million at March 30, 2012.

NOTE 18 — SELECTED QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

The following table presents selected unaudited quarterly financial information for 2011.

	December 31	September 30	June 30	March 31
2011				
Oil and natural gas revenues	$14,991,038	$17,446,638	$20,863,572	$ 13,698,578
Realized gain on derivatives	2,868,720	1,435,340	952,450	1,849,750
Unrealized (loss) gain on derivatives	3,603,821	2,870,086	331,730	(1,668,115)
Expenses	15,783,543	15,469,253*	14,952,309	48,346,769
Other (expense) income	(308,999)	(88,930)	(88,856)	(35,366)
Income (loss) before income taxes	5,371,037	6,193,881*	7,106,587	(34,501,922)
Income tax provision (benefit)	1,430,429	60	(45,636)	(6,906,257)
Net income (loss)	$ 3,940,608	$ 6,193,821*	$ 7,152,223	(27,595,665)
Earnings (loss) per common share				
Basic				
Class A	$ 0.09	$ 0.14*	$ 0.17	$ (0.65)
Class B	$ 0.16	$ 0.21*	$ 0.23	$ (0.58)
Diluted				
Class A	$ 0.09	$ 0.14*	$ 0.17	$ (0.65)
Class B	$ 0.16	$ 0.21*	$ 0.23	$ (0.58)

* Revised

The financial information presented above for the quarter ended September 30, 2011 presents an increase in the previously reported general and administrative expenses from $3,682,920 to $4,207,301, an increase in total expenses from $14,944,872 to $15,469,253, a decrease in operating income from $6,807,192 to $6,282,811, a decrease in income before income taxes from $6,718,262 to $6,193,881, a decrease in net income from $6,718,202 to $6,193,821 and a decrease in basic and diluted earnings per share from $0.15 to $0.14 and from $0.22 to $0.21 for Class A common shares and Class B common shares, respectively, to reflect an additional $524,381 in non-cash, stock-based compensation expense recorded during the quarter ended September 30, 2011. This adjustment resulted from the change in the accounting method used to determine the fair value of the Company's outstanding stock options from the intrinsic value method to the fair value method. During the audit of its December 31, 2011 financial statements, the Company discovered the need for this adjustment to effect the change in accounting method during the quarter ended September 30, 2011. This change in accounting method was previously applied in the quarter ended December 31, 2011. The effect of this change on the previously reported financial statements for the nine months ended September 30, 2011 is an increase in general and administrative expenses from $9,394,964 to $9,919,345, an increase in total expenses from $78,243,950 to $78,768,331, an increase in operating loss from $20,463,921 to $20,988,302, an increase in loss before income taxes from $20,677,073 to $21,201,454, an increase in net loss from $13,725,240 to $14,249,621 and a decrease in basic and diluted earnings per share from $(0.33) to $(0.34) and from $(0.13) to $(0.14) for Class A common shares and Class B common shares, respectively. This adjustment to the September 30, 2011 quarterly financial information had no impact on the amounts reported for the full year ended December 31, 2011.

NOTE 18 — SELECTED QUARTERLY FINANCIAL INFORMATION (UNAUDITED) — Continued

The following table presents selected unaudited quarterly financial information for 2010.

	December 31	September 30	June 30	March 31
2010				
Oil and natural gas revenues	$ 8,859,464	$8,454,725	$ 7,537,345	$9,190,073
Realized gain on derivatives	2,311,380	1,172,040	1,514,400	301,560
Unrealized (loss) gain on derivatives	(2,673,837)	2,540,813	(2,821,705)	6,093,455
Expenses	9,852,439	7,980,371	7,855,459	7,030,719
Other (expense) income	(162,935)	78,621	126,037	95,690
Income (loss) before income taxes	(1,518,367)	4,265,828	(1,499,382)	8,650,059
Income tax provision (benefit)	(522,125)	1,584,375	(515,597)	2,974,522
Net income (loss)	$ (996,242)	$2,681,453	$ (983,785)	$5,675,537
Earnings (loss) per common share				
Basic				
Class A	$ (0.03)	$ 0.07	$ (0.03)	$ 0.14
Class B	$ 0.04	$ 0.14	$ 0.03	$ 0.21
Diluted				
Class A	$ (0.03)	$ 0.07	$ (0.03)	$ 0.14
Class B	$ 0.04	$ 0.14	$ 0.03	$ 0.21

BOARD OF DIRECTORS AND SPECIAL ADVISORS
(From left to right):
(Row 1) Stephen A. Holditch; David M. Laney; Joseph Wm. Foran; Margaret B. Shannon; Marlan W. Downey; (Row 2) Edward R. Scott, Jr.; W.J. "Jack" Sleeper, Jr.; Gregory E. Mitchell; Michael C. Ryan; Steven W. Ohnimus; Charles L. Gummer

CORPORATE INFORMATION

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New York Stock Exchange (NYSE): MTDR

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STOCK TRANSFER AGENT & REGISTRAR
Please direct general questions about shareholder accounts, stock certificates, transfer of shares or duplicate mailings to our transfer agent:

Registrar & Transfer Company
10 Commerce Drive
Cranford, NJ 07016
www.rtco.com
(800) 368-5948
Email: info@rtco.com

FINANCIAL INFORMATION REQUESTS
To receive additional copies of our Annual Report on Form 10-K as filed with the SEC or to obtain other information, please contact Wade Massad at our corporate headquarters.

Email: info@matadorresources.com

EXECUTIVE OFFICERS
Joseph Wm. Foran
President & Chief Executive Officer
David E. Lancaster
Executive Vice President, Chief Operating Officer and Chief Financial Officer
Matthew V. Hairford
Executive Vice President — Operations
David F. Nicklin
Executive Director — Exploration
Wade I. Massad
Executive Vice President — Capital Markets
Bradley M. Robinson
Vice President — Reservoir Engineering
Scott E. King
Co-Founder & Vice President — Geophysics & New Ventures

OFFICER CERTIFICATIONS
Our Form 10-K filed with the SEC is included herein, excluding all exhibits other than our Section 302 and 906 certifications by the CEO and CFO. We will send shareholders our Form 10-K exhibits and any of our corporate governance documents, without charge, upon request.

Note that these documents are also available on our website at www.matadorresources.com.

BOARD OF DIRECTORS
Joseph Wm. Foran
Chairman of the Board
David M. Laney
Lead Director
Attorney; Former Chairman, Amtrak
Charles L. Gummer
President & Chief Executive Officer, Comerica Bank — Texas, Retired
Dr. Stephen A. Holditch
Professor of Petroleum Engineering, Texas A&M University
Gregory E. Mitchell
President & Chief Executive Officer, Toot'n Totum Food Stores, Convenience Stores, Fueling Locations
Dr. Steven W. Ohnimus
General Manager — Partner Operated Ventures, Unocal Corporation, Retired
Michael C. Ryan
Partner, Berens Capital Management, Investment Firm
Margaret B. Shannon
Vice President & General Counsel, BJ Services Company, Oilfield Services, Retired

SPECIAL ADVISORS
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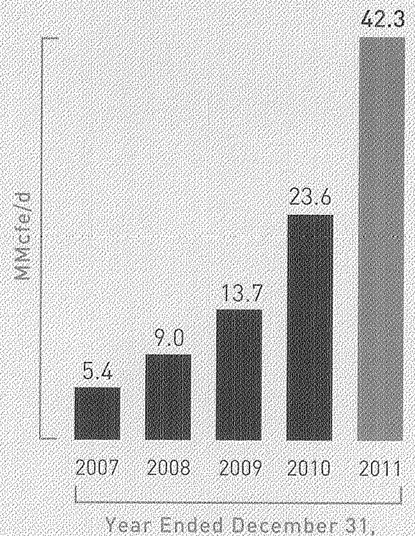
Edward R. Scott, Jr.
Real Estate Developer; Attorney, Retired
W.J. "Jack" Sleeper, Jr.
President & Chief Operating Officer, DeGolyer and McNaughton, Worldwide Petroleum Consulting, Retired

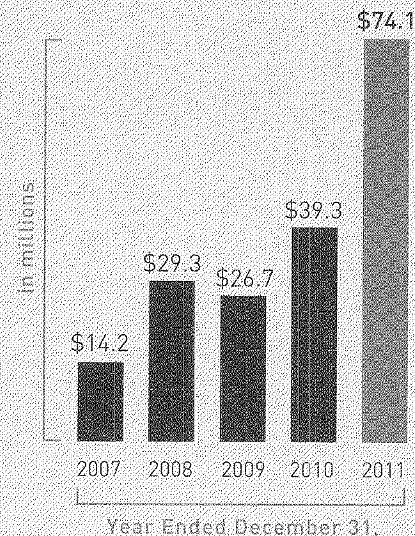
A YEAR OF GROWTH.

AVERAGE DAILY GAS EQUIVALENT PRODUCTION

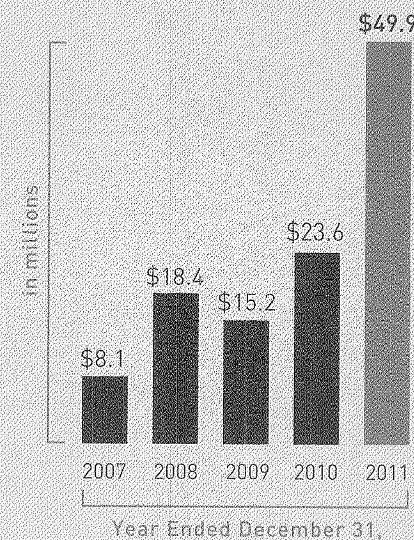


TOTAL REALIZED REVENUES

(INCLUDING REALIZED GAIN ON DERIVATIVES)



ADJUSTED EBITDA



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