Matador Resources Co
Form S-1/A
December 30, 2011
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As filed with the Securities and Exchange Commission on December 30, 2011

Registration No. 333-176263

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Amendment No. 2

to

Form S-1

REGISTRATION STATEMENT

UNDER

THE SECURITIES ACT OF 1933

Matador Resources Company

(Exact name of registrant as specified in its charter)

Texas	**1311**	**27-4662601**
(State or other jurisdiction of incorporation or organization)	**(Primary Standard Industrial Classification Code Number)**	**(I.R.S. Employer Identification No.)**

One Lincoln Centre

5400 LBJ Freeway, Suite 1500

Dallas, Texas 75240

(972) 371-5200

(Address, including zip code, and telephone number, including area code, of registrant s principal executive offices)

Joseph Wm. Foran

Chairman, President and Chief Executive Officer

Matador Resources Company

5400 LBJ Freeway, Suite 1500

Dallas, Texas 75240

(972) 371-5200

(Name, address, including zip code, and telephone number, including area code, of agent for service)

Copies to:

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2323 Victory Avenue, Suite 700	**1445 Ross Avenue, Suite 3700**
Dallas, Texas 75219	**Dallas, Texas 75202**
(214) 651-5000	**(214) 979-3000**

Approximate date of commencement of proposed sale to the public: As soon as practicable after the effective date of this registration statement.

If any of the securities being registered on this Form are to be offered on a delayed or continuous basis pursuant to Rule 415 under the Securities Act of 1933 check the following box: ¨

If this Form is filed to register additional securities for an offering pursuant to Rule 462(b) under the Securities Act, please check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. ¨

If this Form is a post-effective amendment filed pursuant to Rule 462(c) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. ¨

If this Form is a post-effective amendment filed pursuant to Rule 462(d) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. ¨

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

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

CALCULATION OF REGISTRATION FEE

Title of Each Class of Securities to Be Registered	**Amount to be Registered(1)**	**Proposed Maximum Offering Price Per Share**	**Proposed Maximum Aggregate Offering Price(2)**	**Amount of Registration Fee(3)**
Common Stock, par value $0.01 per share			$150,000,000	$17,415

(1) Includes shares of common stock which may be issued on exercise of a 30-day option granted to the underwriters to cover over-allotments, if any, and shares to be sold by certain selling shareholders.
(2) Estimated solely for the purpose of calculating the registration fee pursuant to Rule 457(a) under the Securities Act of 1933, as amended.
(3) The registration fee was previously paid.

The registrant hereby amends this registration statement on such date or dates as may be necessary to delay its effective date until the registrant shall file a further amendment which specifically states that this registration statement shall thereafter become effective in accordance with Section 8(a) of the Securities Act of 1933 or until the registration statement shall become effective on such date as the Commission acting pursuant to said Section 8(a), may determine.

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The information in this prospectus is not complete and may be changed. Neither we nor the selling shareholders may sell these securities until the registration statement filed with the Securities and Exchange Commission is effective. This prospectus is not an offer to sell these securities and we and the selling shareholders are not soliciting offers to buy these securities in any state where the offer or sale is not permitted.

(Subject to completion, dated December 30, 2011)

PROSPECTUS Issued , 2012

Shares

Matador Resources Company

Common Stock

Matador Resources Company is offering shares of its common stock, and the selling shareholders are offering shares of our common stock. This is our initial public offering, and no public market currently exists for our shares. We anticipate that the initial public offering price of our common stock will be between $ and $ per share. We will not receive any of the proceeds from the sale of shares by the selling shareholders.

We intend to apply to list our common stock on the New York Stock Exchange under the symbol MTDR.

Investing in our common stock involves risks. See Risk Factors beginning on page 20.

PRICE $ PER SHARE

	Price to Public	Underwriting Discounts and Commissions[1]	Proceeds to Company	Proceeds to Selling Shareholders
Per Share	$	$	$	$
Total	$	$	$	$

(1) See Underwriters for additional items of underwriting compensation.

We have granted the underwriters the right to purchase up to an additional shares of common stock to cover over-allotments.

The Securities and Exchange Commission and state securities regulators have not approved or disapproved of these securities, or determined if this prospectus is truthful or complete. Any representation to the contrary is a criminal offense.

The underwriters expect to deliver the shares of common stock to purchasers on , 2012.

RBC Capital Markets **Citigroup**

, 2012

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You should rely only on the information contained in this prospectus and any free writing prospectus prepared by or on behalf of us or to which we have referred you. Neither we nor the selling shareholders have authorized anyone to provide you with information different from that contained in this prospectus and any free writing prospectus. We and the selling shareholders are offering to sell shares of common stock, and seeking offers to buy shares of common stock, only in jurisdictions where offers and sales are permitted. The information in this prospectus is accurate only as of the date of this prospectus, regardless of the time of delivery of this prospectus or any sale of the common stock.

Until , 2012, all dealers that buy, sell or trade our common stock, whether or not participating in this offering, may be required to deliver a prospectus. This requirement is in addition to the dealers obligation to deliver a prospectus when acting as underwriters and with respect to their unsold allotments or subscriptions.

Industry and Market Data

The market data and certain other statistical information used throughout this prospectus are based on independent industry publications, government publications or other published independent sources. Although we believe these third party sources are reliable and that the information is accurate and complete, we have not independently verified the information. Some data is also based on our good faith estimates.

PROSPECTUS SUMMARY

This summary provides a brief overview of information contained elsewhere in this prospectus. You should read the entire prospectus carefully before making an investment decision, including the information presented under the headings Risk Factors, Cautionary Note Regarding Forward-Looking Statements and Management s Discussion and Analysis of Financial Condition and Results of Operations and the historical consolidated financial statements and related notes thereto included elsewhere in this prospectus. Unless otherwise indicated, information presented in this prospectus assumes that the underwriters option to purchase additional common shares is not exercised. We have provided definitions for certain oil and natural gas terms used in this prospectus in the Glossary of Oil and Natural Gas Terms beginning on page A-1 of this prospectus.

In this prospectus, unless the context otherwise requires, the terms we, us, our, and 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. See Organizational Structure on page 12 and Corporate Reorganization on page 164 of this prospectus.

In this prospectus, 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 this offering, as the Class A common stock will be the only class of common stock authorized after this offering, 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 this offering. See Description of Capital Stock. In addition, in this prospectus, we have assumed that 285,000 shares of common stock will be issued to certain holders of stock options immediately prior to consummation of this offering in connection with the sale of these shares by the option holders as selling shareholders in this offering.

Matador Resources Company

Overview

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, 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. These plays are a key part of our growth strategy, and we believe they currently represent two of the most active and economically viable unconventional resource plays in North America. We expect the majority of our near-term capital expenditures will focus on increasing our production and reserves from the Eagle Ford and Haynesville shale plays as we seek to capitalize on the relative economics of each play. 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 Joseph Wm. Foran, Chairman, President and CEO, and Scott E. King, Co-Founder and Vice President, Geophysics and New Ventures, with an initial equity investment of approximately $6.0 million. Shortly thereafter, investors contributed approximately $46.5 million to provide a total initial capitalization of approximately $52.5 million. Most of this initial capital was provided by the same institutional and individual investors who helped capitalize Mr. Foran s previous company, Matador Petroleum Corporation.

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.

With an average of more than 25 years of oil and natural gas industry experience, our management team has extensive expertise in exploring for and developing hydrocarbons in multiple U.S. basins. Members of our management team have participated in the assimilation of numerous lease positions and in the drilling and completion of hundreds of vertical and horizontal wells in unconventional resource plays.

Since our first well in 2004, we have drilled or participated in drilling 213 wells through September 30, 2011, including 83 Haynesville and six Eagle Ford wells. From December 31, 2008 through September 30, 2011, we grew our estimated proved reserves from 20.0 Bcfe to 161.8 Bcfe. At September 30, 2011, 35% of our estimated proved reserves were proved developed reserves and 96% of our estimated proved reserves were natural gas. We also grew our average daily production by approximately 162% from 9.0 MMcfe per day for the year ended December 31, 2008 to 23.6 MMcfe per day for the year ended December 31, 2010. In addition, as a result of production from new wells that were completed in 2011, our daily production for the nine months ended September 30, 2011 averaged approximately 42.5 MMcfe per day. We have achieved this growth while lowering operating costs (consisting of lease operating expenses and production taxes and marketing expenses) from $1.91 per Mcfe for the year ended December 31, 2008, to $0.90 per Mcfe for the nine months ended September 30, 2011, or a decrease of approximately 53%.

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The following table presents certain summary data for each of our operating areas as of and for the nine months ended September 30, 2011:

		Producing Wells		Total Identified Drilling Locations(1)		Estimated Net Proved Reserves		Avg. Daily Production
	Net Acreage	Gross	Net	Gross	Net	Bcfe(2)	% Developed	(MMcfe)
South Texas:								
Eagle Ford	28,906	5.0	3.4	197.0	157.1	8.4	51.0	3.2
Austin Chalk	14,849			16.0	16.0			
Area Total(3)	28,906	5.0	3.4	213.0	173.1	8.4	51.0	3.2
NW Louisiana/E Texas:								
Haynesville	14,705	83.0	10.6	545.0	103.9	136.6	25.4	32.1
Cotton Valley(4)	23,236	108.0	71.7	60.0	36.0	16.1	100.0	7.0
Area Total(5)	25,477	191.0	82.3	605.0	139.9	152.7	33.3	39.1
SW Wyoming, NE Utah, SE Idaho	135,862							
SE New Mexico, West Texas	7,519	13.0	5.7			0.7	100.0	0.2
Total	197,764	209.0	91.4	818.0	313.0	161.8	34.5	42.5

(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 September 30, 2011, these identified drilling locations included 2 gross and 2 net locations to which we have assigned proved undeveloped reserves in the Eagle Ford and 95 gross and 15 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 September 30, 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 September 30, 2011, our properties included approximately 52,000 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 (see Recent Developments). We have identified 197 gross locations and 157 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 September 30, 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

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locations for drilling. At September 30, 2011, these identified potential future drilling locations in the Eagle Ford shale play included 2 gross and 2 net locations to which we have assigned proved undeveloped reserves.

In addition, at September 30, 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, almost 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. Just 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 September 30, 2011, we have identified 545 gross locations and 104 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 545 gross locations identified for future drilling, 470 of these locations (53 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 September 30, 2011, these identified potential future drilling locations in the Haynesville shale play included 95 gross and 15 net locations 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. 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 213 gross wells we have drilled or participated in drilling, we drilled approximately half of these wells as the operator. At September 30, 2011, we were the operator for approximately 80% 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.

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Our net proceeds from this offering, after repaying the then outstanding borrowings under our revolving credit agreement ($113.0 million at December 30, 2011, excluding $1.3 million in outstanding letters of credit), when taken together with our cash flows and future potential borrowings under our credit agreement, will be used to fund our 2012 capital expenditure requirements and for potential acquisitions of interests and acreage (none of which have been identified). We anticipate that we may need to access future borrowings under our credit agreement within 60 to 90 days following completion of this offering to fund a portion of our 2012 capital expenditure requirements in excess of amounts available from our cash flows and the net proceeds of this offering. See Use of Proceeds.

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

	2012 Anticipated Drilling						2012 Anticipated Capital Expenditure Budget (in millions)(2)		
	Gross Wells(1)			Net Wells(1)					
	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	2.5	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 September 30, 2011, just over 90% of our

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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

In December 2011, we amended and restated our senior secured revolving credit agreement. This amendment increased the maximum facility amount from $150 million to $400 million. Borrowings are limited to the lesser of $400 million or the borrowing base, which will be $100 million immediately following this offering.

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. We are the operator and have a 100% working interest in these three wells.

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 and began producing to sales in late December 2011. We are the operator of this well and paid 100% of the costs to drill and complete the well. We will receive 85% of the revenues attributable to the working interest in the well until we have recovered all of our acquisition, drilling and completion costs, after which time, our partner will receive 50% of the revenues attributable to the working interest in the well and we and our partner will each maintain a 50% working interest in the well.

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.

In March 2011, first sales of natural gas began from our Williams 17 H#1 well, located in what we believe to be the core area of the Haynesville shale play in northwest Louisiana. We began producing this well at a constrained rate of about 10.0 MMcf of natural gas per day. During November 2011, this well produced at an average daily rate of 4.5 MMcf of natural gas per day, and through November 30, 2011, had produced approximately 1.7 Bcf of natural gas. We are the operator and have a 100% working interest and a favorable 87.5% net revenue interest in this well.

In February 2011, we completed our third operated Eagle Ford horizontal well, the Affleck #1H, in eastern Dimmit County, Texas. This well tested at approximately 415 Bbls of oil and 5.4 MMcf of natural gas per day during an initial flow test. During November 2011, this well produced at an average daily rate of 0.9 MMcf of natural gas and 70 Bbls of oil per day. We are the operator and have a 100% working interest in this well.

In January 2011, we completed a private placement offering of 1,922,199 shares of our Class A common stock at $11.00 per share for an aggregate amount of $21,144,189.

In January 2011, we completed our second operated Eagle Ford horizontal well, the Martin Ranch #1H, in northeastern LaSalle County, Texas. 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 November 2011, the well produced at an average daily rate of approximately 520 Bbls of oil and 0.6 MMcf of natural gas per day, and through November 30, 2011, had produced a total of approximately 111,000 Bbls of oil and 135 MMcf of natural gas. We are the operator and have a 100% working interest in this well.

In January 2011, first sales of oil and natural gas began from our first operated Eagle Ford horizontal well, the JCM Jr. Minerals #1H, in southern LaSalle County, at approximately 3.4 MMcf of natural gas and 135 Bbls of condensate per day. During November 2011, the well produced at an average daily rate of approximately 0.6 MMcf of natural gas and 12 Bbls of condensate per day, and through November 30, 2011, had produced a total of approximately 416 MMcf of natural gas and 10,900 Bbls of condensate. We are the operator and have a 100% working interest in this well.

In January 2011, we completed our first horizontal Cotton Valley well, the Tigner Walker H#1-Alt., in DeSoto Parish, Louisiana. First sales of natural gas from this well began in late January at approximately 4.6 MMcf of natural gas per day. During November 2011, the well produced at an average daily rate of approximately 1.9 MMcf of natural gas per day, and through November 30, 2011, had produced a total of approximately 900 MMcf of natural gas. We are the operator and have a 100% working interest in this well subject to a reversionary interest at payout.

On December 31, 2010, first sales of natural gas began from our L.A. Wildlife H#1 Alt. horizontal well, located in what we believe to be the core area of the Haynesville shale play in northwest Louisiana. We began producing this well at a constrained rate of about 10.0 MMcf of natural gas per day. During November 2011, the well produced at an average daily rate of approximately 10.0 MMcf of natural gas per day, and through November 30, 2011, had produced a total of approximately 3.2 Bcf of natural gas. We are the operator and have a 95% working interest in this well.

Business Strategies

Our goal is to increase shareholder value by building reserves, production and cash flows at an attractive return on invested capital. We plan to achieve our goal by executing the following strategies:

Focus Exploration and Development Activity on Our Eagle Ford and Haynesville Shale Assets. We have established core acreage positions in the Eagle Ford and Haynesville shale plays, which we believe are two of the most active and economically viable shale plays in North America. 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.

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Since just 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 at September 30, 2011, we have the flexibility to develop our acreage in a disciplined manner in order to maximize the resource recovery from these assets. We believe the economics for development in these two areas are attractive at current commodity prices.

Identify, Evaluate and Exploit Oil Plays to Create a More Balanced Portfolio.
Although most of our current proved reserves are classified as natural gas, we have been evaluating various oil plays to find and execute upon opportunities that would fit well with our exploration and operating strategies. 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. We believe oil and liquids opportunities represent about 94% of our anticipated 2012 capital expenditure budget. We expect to continue to create and acquire additional prospects and opportunities for the exploration and production of oil and liquids.

Pursue Opportunistic Acquisitions.
We believe our management team s familiarity with our key operating areas and its contacts with the operators and mineral owners in those regions enable us to identify high-return opportunities at attractive prices. We actively pursue opportunities to acquire unproved and unevaluated acreage, drilling prospects and low-cost producing properties within our core areas of operations where we have operational control and can enhance value and performance. We view these acquisitions as an important component of our business strategy and intend to selectively make acquisitions on attractive terms that complement our growth and help us achieve economies of scale.

Maintain Our Financial Discipline.
As an operator, we leverage advanced technologies and integrate the knowledge, judgment and experience of our management and technical teams. We believe our team demonstrates financial discipline that is achieved by our approach to evaluating and analyzing prospects and prior drilling and completion results before allocating capital and is reflected in the improvements our team has attained on reducing unit costs. When we are not the operator, we proactively engage with the operators in an effort to ensure similar financial discipline. Additionally, we conduct our own internal geological and engineering studies on these prospects and provide input on the drilling, completion and operation of many of these non-operated wells pursuant to our agreements and relationships with the operators. Through these methods and practices, we believe we are well-positioned to control the expenses and timing of development and exploitation of our properties.

Maintain Proactive and Ongoing Relationships with Other Industry Participants.
We believe maintaining proactive and ongoing relationships with other industry operators and vendors enhances our understanding of the shale plays and allows us to leverage their expertise without having to commit substantial capital. We currently participate in various drilling activities with larger industry participants, including affiliates of Chesapeake Energy Corporation, EOG Resources, Inc., Royal Dutch Shell plc and others. We are also active participants in three industry shale consortia: the North American Gas Shale, Haynesville and Bossier Shale and Eagle

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Ford Shale consortia organized by Core Laboratories, LP. As active members in various professional societies, our staff and board members also regularly interact on a professional basis with other industry participants.

Competitive Strengths

We believe our prior success is, and our future performance will be, directly related to the following combination of strengths that will enable us to implement our strategies:

High Quality Asset Base in Attractive Areas.
We have key acreage positions in active areas of the Eagle Ford and Haynesville shale plays. We believe our assets in these plays are characterized by low geological risk and similar repeatable drilling opportunities that we expect will result in a predictable production growth profile. The commodity mix of our production and reserves is expected to become more balanced as a result of our planned activities on our Eagle Ford and Austin Chalk acreage, which is located in oil and liquids prone areas of the plays. In addition to the Haynesville shale, our east Texas and north Louisiana assets have multiple, recognized geologic horizons, including the Middle Bossier shale, Cotton Valley and Hosston (Travis Peak) formations. We also believe there is additional resource potential in our oil and natural gas prospects in southeast New Mexico and west Texas, along with our natural gas prospects in southwest Wyoming and adjacent areas in Utah and Idaho.

Large, Multi-year, Development Drilling Inventory.
Within our northwest Louisiana/east Texas and south Texas regions, we have identified 818 gross and 313 net drilling locations, including 197 gross and 157 net locations in the Eagle Ford shale play and 545 gross and 104 net locations in the Haynesville shale play. At September 30, 2011, these identified drilling locations included 2 gross and 2 net locations to which we have assigned proved undeveloped reserves in the Eagle Ford shale play and 95 gross and 15 net locations to which we have assigned proved undeveloped reserves in the Haynesville shale play. We have identified 28 gross and 26 net locations in the Eagle Ford shale play and 25 gross and 2 net locations in the Haynesville shale play that we expect to drill in 2012, the completion of which would represent approximately 14% and 5% of our identified gross drilling locations in these two areas at September 30, 2011, respectively. Additionally, we expect to identify and develop additional locations across our broad exploration portfolio as we evaluate our Cotton Valley, Austin Chalk, Meade Peak and Delaware and Midland Basin assets. We believe our multi-year, identified drilling inventory and exploration portfolio provide visible near-term growth in our production and reserves, and highlight the long-term resource potential across our asset base.

Financial Flexibility to Fund Expansion.
Historically, we have maintained financial flexibility by obtaining capital through shareholder investments and our operational cash flows while maintaining low levels of indebtedness, which has allowed us to take advantage of acquisition opportunities as they arise. Upon the completion of this offering and the repayment of the then outstanding borrowings under our credit agreement ($113.0 million outstanding, excluding $1.3 million in outstanding letters of credit, at December 30, 2011), we expect to have at least $ million in cash, cash equivalents and certificates of deposit and at least $98.7 million available for borrowings under our credit agreement after giving effect to outstanding letters of credit. Excluding any possible acquisitions,

we expect to maintain our current financial flexibility by funding our entire 2012 capital expenditure budget through the net proceeds we receive from this offering, together with our cash flows and future potential borrowings under our credit agreement. We anticipate that we may need to access future borrowings under our credit agreement within 60 to 90 days following completion of this offering to fund a portion of our 2012 capital expenditure requirements in excess of amounts available from our cash flows and the net proceeds of this offering. Our availability of capital as described above will also allow us to maintain our competitiveness in seeking to acquire additional oil and natural gas properties as opportunities arise. A strong balance sheet and interest savings should also reduce unit costs and increase profitability. In addition, since a large portion of our Eagle Ford and Haynesville acreage was held by production at September 30, 2011, we have the financial flexibility to allocate our capital when we believe it is economical and justified.

Experienced and Incentivized Management, Technical Team and Board.
Our management and technical teams possess extensive oil and natural gas expertise with an average of over 25 years of relevant industry experience from companies such as Matador Petroleum Corporation, S. A. Holditch & Associates, Inc., Schlumberger Limited, Conoco and ARCO, and we believe they have a demonstrated record of growth and financial discipline over many years. The management team has experience in drilling and completing hundreds of vertical and horizontal wells in unconventional resource plays, including the Cotton Valley, Bossier, Wilcox/Vicksburg, Austin Chalk, Haynesville and Eagle Ford plays. Our management team s experience is complemented by a strong technical team with deep knowledge of advanced geophysical, drilling and completion technologies whose members are active in their professional societies. Additionally, we have a group of board members and special advisors with considerable experience and expertise in the oil and natural gas industry and in managing other successful enterprises who provide insight and perspective regarding our business and the evaluation, exploration, engineering and development of our prospects. In addition to its considerable experience, our management team currently owns and will continue to own a significant direct ownership interest in us immediately following the completion of this offering. We believe our management team s direct ownership interest, as well as its ability to increase its holdings over time through our long-term incentive plan, aligns management s interests with those of our shareholders.

Extensive Geologic, Engineering and Operational Experience in Unconventional Reservoir Plays.
The individuals on our technical team are highly experienced in analyzing unconventional reservoir plays and in horizontal drilling, completion and production operations in a number of geographic areas. Our geologists have extensive experience in analyzing unconventional reservoir plays throughout the United States, including our principal areas of interest, by using the latest imaging technology, such as 2-D and 3-D seismic interpretation, and petrophysical analysis. In addition, our technical team has been directly involved in over 26 different horizontal well drilling and/or operations programs in both onshore and offshore formations located in the United States and abroad. Our team s diverse and broad horizontal drilling experience includes most, if not all, techniques used in modern day drilling. Additionally, our team has in-depth experience with various horizontal completion techniques and their applications in multiple unconventional plays. We intend to leverage our team s geological expertise and horizontal drilling and completion experience to develop and exploit our large, multi-year development drilling inventory.

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Multi-Disciplined Approach to New Opportunities.
Our process for evaluating and developing new oil and natural gas prospects is a result of what we believe is an organizational philosophy that is dedicated to a systematic, multi-disciplinary approach to new opportunities with an emphasis on incorporating petroleum systems, geosciences, technology and finance into the decision-making process. We recognize the importance of consulting multiple individuals in our organization across all disciplines and all levels of responsibility prior to making exploration, acquisition or development decisions and the formulation of key criteria for successful exploration and development projects in any given play to enhance our decision-making. We also conduct a post-completion review of our major decisions to determine what we did right and where we need to improve. At times, this approach results in a decision to accelerate our drilling program or expand our positions in certain areas. Other times, this approach results in a decision to mitigate risk associated with our exploration and development programs by sharing operational risks and costs with other industry participants or exiting an area altogether. We believe this multi-disciplined approach underpins our track record of value creation and represents the best way to deliver consistent, year-over-year results to our shareholders.

Certain Risk Factors

An investment in our common stock involves risks that include the speculative nature of oil and natural gas exploration and production, competition, volatile oil and natural gas prices and other material factors. In particular, the following considerations may offset our competitive strengths or have a negative effect on both our business strategy as well as on activities on our properties, which could cause a decrease in the price of our common stock and result in a loss of all or a portion of your investment:

- Our success is dependent on the prices of oil and natural gas. Low oil or natural gas prices or the substantial volatility in these prices may adversely affect our financial condition and our ability to meet our capital expenditure requirements and financial obligations;

- Drilling for and producing oil and natural gas are high-risk activities with many uncertainties that could adversely affect our business, financial condition, results of operations and cash flows;

- 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 reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves;

- 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;

- 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;

- 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;

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- Drilling locations that we decide to drill may not yield oil or natural gas in commercially viable quantities;

- We may have accidents, equipment failures or mechanical problems while drilling or completing wells or in production activities, which could adversely affect our business;

- We have limited control over activities on properties we do not operate;

- Approximately 67% of our total proved reserves at September 30, 2011 consisted of undeveloped and developed non-producing reserves, and those reserves may not ultimately be developed or produced;

- 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; and

- 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.

For a discussion of these risks and other considerations that could negatively affect us, including risks related to this offering and our common stock, see Risk Factors beginning on page 21 and Cautionary Note Regarding Forward-Looking Statements.

Organizational Structure

Matador Resources Company was formed as a Texas corporation in July 2003. Pursuant to the terms of the corporate reorganization that was completed on August 9, 2011, former Matador Resources Company, now known as MRC Energy Company, became a wholly owned subsidiary of current Matador Resources Company, formerly known as Matador Holdco, Inc. In connection with the reorganization, former Matador Resources Company changed its corporate name to MRC Energy Company, and Matador Holdco, Inc. changed its corporate name to Matador Resources Company.

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The following diagram indicates our ownership structure and organizational structure after giving effect to our corporate reorganization and this offering. The shareholder ownership information set forth below is based on the beneficial ownership of our common stock after consummation of this offering based on the number of shares beneficially owned by our current shareholders at , 2012.

Corporate Information

We are headquartered in Dallas, Texas. Our executive offices and mailing address are at One Lincoln Centre, 5400 LBJ Freeway, Suite 1500, Dallas, Texas 75240. Our telephone number is (972) 371-5200. We expect to have an operational website that meets Securities and Exchange Commission, or SEC, and New York Stock Exchange, or NYSE, requirements concurrently with, or prior to, the completion of this offering. Information on our website or any other website is not and will not be incorporated by reference herein and does not and will not constitute a part of this prospectus.

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The Offering

Issuer	Matador Resources Company
Selling shareholders	See Principal and Selling Shareholders.
Common stock offered by us	shares (shares if the underwriters over-allotment is exercised in full)
Common stock offered by selling shareholders	shares
Common stock outstanding after offering	shares (shares if the underwriters over-allotment is exercised in full) The number of shares to be outstanding after this offering is based on shares of our common stock outstanding at , 2012 and excludes additional shares that are authorized for future issuance under our equity incentive plans, of which shares may be issued subsequent to the offering pursuant to outstanding stock options.
Over-allotment option	We have granted the underwriters a 30-day option to purchase up to an aggregate of additional shares of our common stock to cover any over-allotments.
Use of proceeds	We estimate that our net proceeds from this offering will be approximately $ million after deducting the underwriting discounts and commissions and estimated offering expenses. We intend to use the net proceeds we receive from this offering to repay the then outstanding borrowings under our credit agreement ($113.0 million outstanding, excluding $1.3 million in outstanding letters of credit, at December 30, 2011). The remaining net proceeds will be used to fund a portion of our anticipated 2012 capital expenditure budget. We will not receive any of the proceeds from the sale of shares of our common stock by the selling shareholders. See Use of Proceeds.
Dividend policy	We do not anticipate paying any cash dividends on our common stock.
Risk factors	You should carefully read and consider the information beginning on page 20 of this prospectus set forth under the heading Risk Factors and all other information set forth in this prospectus before deciding to invest in our common stock.
New York Stock Exchange Symbol	MTDR

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Summary Financial, Reserves and Operating Data

You should read the following summary financial, reserves and operating data in conjunction with Selected Historical Consolidated and Other Financial Data, Management s Discussion and Analysis of Financial Condition and Results of Operations, Business and our audited and unaudited historical consolidated financial statements and related notes thereto included elsewhere in this prospectus. The financial information included in this prospectus may not be indicative of our future results of operations, financial position and cash flows.

Financial Data

The following tables set forth summary historical consolidated financial information for the company and its subsidiaries. The historical consolidated financial information is derived from the audited consolidated financial statements for the company and its subsidiaries at and for the years ended December 31, 2010, 2009 and 2008 and the unaudited condensed consolidated financial statements for the company and its subsidiaries at and for the nine months ended September 30, 2011 and 2010. The balance sheet data has also been adjusted to reflect the estimated net proceeds to be received by us from this offering. The audited consolidated financial statements for the company and its subsidiaries at and for the years ended December 31, 2010, 2009 and 2008 and the unaudited condensed consolidated financial statements for the company and its subsidiaries at and for the nine months ended September 30, 2011 and 2010 are contained elsewhere in this prospectus. Our consolidated financial statements for the years ended December 31, 2010, 2009 and 2008 were audited by Grant Thornton LLP.

	Year Ended December 31,			Nine Months Ended September 30,	
	2010	2009	2008	2011	2010
				(Unaudited)	(Unaudited)
(In thousands, except per share data)					
Statement of operations data:					
Revenues:					
Oil and natural gas revenues	$ 34,042	$ 19,039	$ 30,645	$ 52,009	$ 25,182
Realized gain (loss) on derivatives	5,299	7,625	(1,326)	4,237	2,988
Unrealized gain (loss) on derivatives	3,139	(2,375)	3,592	1,534	5,813
Total revenues	42,480	24,289	32,911	57,780	33,983
Expenses:					
Production taxes and marketing	1,982	1,077	1,639	4,801	1,235
Lease operating	5,284	4,725	4,667	5,639	3,801
Depletion, depreciation and amortization	15,596	10,743	12,127	22,578	10,931
Accretion of asset retirement obligations	155	137	92	158	107
Full-cost ceiling impairment		25,244	22,195	35,673	
General and administrative	9,702	7,115	8,252	9,395	6,793
Total expenses	32,719	49,041	48,972	78,244	22,867
Operating income (loss)	9,761	(24,752)	(16,061)	(20,464)	11,116
Other:					
Other (expense) income	137	402	139,962[(1)]	(213)	300
Income (loss) before income taxes	9,898	(24,350)	123,901	(20,677)	11,416
Net income (loss)	$ 6,377	$ (14,425)	$ 103,878	$ (13,725)	$ 7,373

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(In thousands, except per share data)	Year Ended December 31, 2010	2009	2008	Nine Months Ended September 30, 2011 (Unaudited)	2010 (Unaudited)
Earnings (loss) per share (basic) [2]					
Class A	$ 0.15	$ (0.37)	$ 2.50	$ (0.33)	$ 0.18
Class B[2]	$ 0.42	$ (0.10)	$ 2.77	$ (0.13)	$ 0.38
Weighted average common shares outstanding (basic)	41,037	40,123	41,385	42,702	40,880
Class A	40,007	39,093	40,355	41,671	39,849
Class B[2]	1,031	1,031	1,031	1,031	1,031

(1) Increase in other income was primarily due to gain on unproved and unevaluated property dispositions in 2008.

(2) At September 30, 2011, we had 1,030,700 shares of Class B common stock issued and outstanding. All shares of Class B common stock will automatically convert on a one-for-one basis into shares of Class A common stock upon the consummation of this offering pursuant to the terms of our certificate of formation. If the Class B common stock were converted at the applicable date, the earnings per share would not be materially different than the Class A earnings per share.

(In thousands)	At December 31, 2010	2009	2008	At September 30, 2011 Actual (Unaudited)	2011 As Adjusted[1] (Unaudited)	2010 (Unaudited)
Balance sheet data:						
Cash and cash equivalents	$ 21,060	$ 104,230	$ 150,768	$ 7,768	$ 31,768	$ 38,618
Certificates of deposit	2,349	15,675	20,782	2,085	2,085	7,429
Net property and equipment	303,880	142,078	125,261	350,279	350,279	227,052
Total assets	346,382	277,400	314,539	383,244	407,244	291,423
Current liabilities	30,097	8,868	35,475	50,102	25,102	19,396
Long term liabilities	34,408	4,210	2,059	64,604	4,604	8,125
Total shareholders equity	$ 281,877	$ 264,321	$ 277,005	$ 268,538	$ 405,538	$ 263,902

(1) As adjusted to give effect to this offering (assuming aggregate net proceeds of $137.0 million are received by us), the application of the estimated net proceeds to be received by us to repay the then outstanding borrowings under our credit agreement ($113.0 million, excluding $1.3 million in outstanding letters of credit, at December 30, 2011), with the balance being added to cash and cash equivalents to fund a portion of our 2012 capital expenditure budget.

(In thousands)	Year Ended December 31, 2010	2009	2008	Nine Months Ended September 30, 2011 (Unaudited)	2010 (Unaudited)
Other financial data:					
Net cash provided by operating activities	$ 27,273	$ 1,791	$ 25,851	$ 34,443	$ 21,390
Net cash (used in) provided by investing activities	(147,334)	(49,415)	115,481	(107,772)	(78,718)
Oil and natural gas properties capital expenditures	(159,050)	(54,244)	(104,119)	(104,733)	(86,031)
Expenditures for other property and equipment	(1,610)	(307)	(3,012)	(3,303)	(934)
Net cash provided by (used in) financing activities	36,891	1,086	419	60,037	(8,284)
Adjusted EBITDA[1]	$ 23,635	$ 15,184	$ 18,411	$ 37,550	$ 17,133

(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 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, 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

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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. GAAP means Generally Accepted Accounting Principles.

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 the 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 reconciliation of Adjusted EBITDA to the GAAP financial measures of net income (loss) and net cash provided by operating activities, respectively.

	Year Ended December 31,			**Nine Months Ended September 30,**	
	2010	**2009**	**2008**	**2011**	**2010**
(In thousands)					
Unaudited Adjusted EBITDA reconciliation to Net Income (Loss):					
Net income (loss)	$ 6,377	$ (14,425)	$ 103,878	$ (13,725)	$ 7,373
Interest expense	3			461	
Total income tax provision (benefit)	3,521	(9,925)	20,023	(6,952)	4,043
Depletion, depreciation and amortization	15,596	10,743	12,127	22,578	10,931
Accretion of asset retirement obligations	155	137	92	158	107
Full-cost ceiling impairment		25,244	22,195	35,673	
Unrealized (gain) loss on derivatives	(3,139)	2,375	(3,592)	(1,534)	(5,812)
Stock option and grant expense	824	622	605	855	466
Restricted stock grants	74	34	60	36	25
Net (gain)/loss on asset sales and inventory impairment	224	379	(136,977)		
Adjusted EBITDA	$ 23,635	$ 15,184	$ 18,411	$ 37,550	$ 17,133

	Year Ended December 31,			**Nine Months Ended September 30,**	
	2010	**2009**	**2008**	**2011**	**2010**
(In thousands)					
Unaudited Adjusted EBITDA reconciliation to Net Cash Provided by Operating Activities:					
Net cash provided by operating activities	$ 27,273	$ 1,791	$ 25,851	$ 34,443	$ 21,390
Net change in operating assets and liabilities	(2,230)	15,717	(17,888)	2,692	(2,846)
Interest expense	3			461	
Current income tax (benefit) provision	(1,411)	(2,324)	10,448	(46)	(1,411)
Adjusted EBITDA	$ 23,635	$ 15,184	$ 18,411	$ 37,550	$ 17,133

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Reserves Data

The following table presents summary data with respect to our estimated net proved oil and natural gas reserves at the dates indicated. The reserves estimates at December 31, 2008 presented in the table below are based on evaluations prepared by our engineering staff, which have been audited by LaRoche Petroleum Consultants, Ltd., independent reservoir engineers. The reserves estimates at December 31, 2010 and 2009 and at September 30, 2011 are based on evaluations prepared by our engineering staff, which have been audited by Netherland, Sewell & Associates, Inc., independent reservoir engineers. These reserves estimates were prepared in accordance with the Securities and Exchange Commission s rules regarding oil and natural gas reserves reporting that were in effect at the time of the preparation of the reserves report. Our total estimated proved reserves are estimated using a conversion ratio of one Bbl per six Mcf.

	At December 31,			At September 30,
	2010	2009	2008	2011
Estimated proved reserves:[1] [2]				
Natural gas (Bcf)	127.4	63.9	19.2	155.3
Oil (MBbls)	152	103	131	1,083
Total (Bcfe)	128.3	64.5	20.0	161.8
Developed proved reserves (Bcfe)	44.1	26.0	20.0	55.8
Percent developed	34.3%	40.3%	100.0%	34.5%
Undeveloped proved reserves (Bcfe)	84.3	38.6		106.0
PV-10 (in thousands)[3]	$ 119,869	$ 70,359	$ 44,069	$ 155,217
Standardized Measure (in thousands)[4]	$ 111,077	$ 65,061	$ 43,254	$ 143,372

(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 index prices were $41.00 per Bbl for oil and $5.710 per MMBtu for natural gas at December 31, 2008. 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-month period from October 2010 to September 2011 were $91.00 per Bbl for oil and $4.158 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, 2008, 2009 and 2010 and at September 30, 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, 2008, 2009 and 2010 and at September 30, 2011 were, in thousands, $815, $5,298, $8,792 and $11,845, 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.

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Unaudited Operating Data

The following table sets forth summary unaudited production results for the company and its subsidiaries for the years ended December 31, 2010, 2009 and 2008 and for the nine month periods ended September 30, 2011 and 2010.

	Year Ended December 31,			Nine Months Ended September 30,	
	2010	**2009**	**2008**	**2011**	**2010**
Production:					
Natural gas (Bcf)	8.4	4.8	3.1	10.9	5.9
Oil (MBbls)	33	30	37	113	24
Total natural gas equivalents (Bcfe)(1)	8.6	5.0	3.3	11.6	6.0
Average net daily production (MMcfe)	23.6	13.7	9.0	42.5	22.0
Average sales price (per Mcfe):					
Average sales price (including effects of hedging)	$ 4.58	$ 5.33	$ 8.86	$ 4.85	$ 4.68
Average sales price (before effects of hedging)	$ 3.96	$ 3.81	$ 9.27	$ 4.48	$ 4.19
Operating expenses (per Mcfe):					
Production taxes and marketing	$ 0.23	$ 0.22	$ 0.50	$ 0.41	$ 0.21
Lease operating	$ 0.61	$ 0.94	$ 1.41	$ 0.49	$ 0.63
Depletion, depreciation and amortization	$ 1.81	$ 2.15	$ 3.67	$ 1.95	$ 1.82
General and administrative	$ 1.13	$ 1.42	$ 2.50	$ 0.81	$ 1.13

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

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RISK FACTORS

You should carefully consider the risks described below before making an investment decision. Our business, financial condition or results of operations could be materially adversely affected by any of these risks. The trading price of our common stock could decline due to any of these risks, and you may lose all or part of your investment.

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.

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Because we expect to produce more natural gas than oil in the immediate future, we will face more risk associated with fluctuations in the price of natural gas than oil. Approximately 98% of our production during the year ended December 31, 2010, 94% of our production during the nine month period ended September 30, 2011 and 96% of our proved reserves at September 30, 2011 are attributable to natural gas. In addition, three of our largest prospects, our Haynesville shale, Cotton Valley properties and our Meade Peak shale, 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 almost 85% of our Eagle Ford acreage is prospective predominantly for oil and liquids production, and we have identified 197 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 would not only reduce our revenue, but could reduce the amount of oil and natural gas that we can produce economically. Should natural gas or oil prices decrease from current 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.

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

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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 north 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 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.

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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. In the future, we may have difficulty expanding our current production or acquiring new properties. 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 prospectus 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

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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 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 September 30, 2011 Consisted of Undeveloped and Developed Non-Producing Reserves, and Those Reserves May Not Ultimately Be Developed or Produced.

At September 30, 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 oil and/or natural gas prices 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. The net proceeds we receive from this offering, our 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.

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;

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- 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.

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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 delay 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

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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 prospectus 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 also acquired other non-operated acreage positions in north 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.

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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.

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.

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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

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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. Our existing oil and natural gas hedges will expire at various times during 2012 and 2013.

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 and February 14, 2011, and may be raised again in the future. The American Jobs Act of 2011 proposed by President Obama also contains similar changes. It is unclear whether any such changes will actually be enacted or, if enacted, how soon any such changes could become effective. The passage of any legislation as a result of the budget 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.

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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.

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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.

Congress is currently considering legislation to amend the federal Safe Drinking Water Act to remove the exemption from restrictions on underground injection of fluids near drinking water sources granted to hydraulic fracturing operations and 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 natural gas production. We routinely use hydraulic fracturing to produce commercial quantities of oil, liquids and natural gas from shale formations such as the Haynesville and the Eagle Ford 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. These bills, 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 U.S. Environmental Protection Agency, or 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 these bills are 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,

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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.

On December 15, 2009, the EPA 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 federal Clean Air Act. 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 on March 31, 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 legislation establishing a cap and trade program, but that legislation appears unlikely to pass. Further, various states have 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 Natural Gas Act of 1938, or NGA, exempts natural gas gathering facilities from regulation by the Federal Energy Regulatory Commission, or 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 on-going 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.

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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 Domenici-Barton Energy Policy Act of 2005, 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 September 30, 2011, we had leasehold interests in approximately 122,000 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

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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.

Upon the completion of this offering and the application of the net proceeds to be received by us, we expect to have available borrowings of approximately $98.7 million under our credit agreement (after giving effect to outstanding letters of credit). Our borrowing base under our credit agreement immediately following the offering will be limited to $100 million. 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,

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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 bear interest at a variable rate of 3.25% plus a Eurodollar-based rate per annum, which equated to approximately 3.6% per annum at December 30, 2011. 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

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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 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 Will Own Approximately % of Our Common Stock after the Consummation of this Offering, Which Could Give Them Influence in Corporate Transactions and Other Matters, and the Interests of Our Management Could Differ From Yours.

Our directors and officers will beneficially own approximately % of our outstanding shares of common stock following this offering based on shares of common stock to be sold in this offering. These shareholders will be 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 this Offering and Our Common Stock

The Market Price and Trading Volume of Our Common Stock May Be Volatile Following this Offering.

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. 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;

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- 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, the selling shareholders or other 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 prospectus;
- 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 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.

There Is Currently No Public Market for Our Common Stock, and an Active Liquid Trading Market for Our Common Stock May Not Develop Following this Offering.

Prior to this offering, there has been no public market for our common stock. We intend to file a listing application with the New York Stock Exchange, or NYSE, for our common stock in connection with this offering, which is subject to official notice of issuance. Liquid and active trading markets usually result in less price volatility and more efficiency in carrying out investors purchase and sale orders. Our common stock may have limited trading volume, and many investors may not be interested in owning our common stock because of the inability to acquire or sell a substantial block of our common stock at one time. Such illiquidity could have an adverse effect on the market price of our common stock. In addition, a shareholder may not be able to borrow funds using our common stock as collateral because lenders may be unwilling to accept the pledge of securities having such a limited market. We cannot assure you that an active trading market for our common stock will develop or, if one develops, be sustained.

The Initial Public Offering Price of Our Common Stock May Not Be Indicative of the Market Price of Our Common Stock after this Offering.

The initial public offering price may not necessarily bear any relationship to our book value or the fair market value of our assets. The initial public offering price will be negotiated between us and representatives of the underwriters, based on numerous factors which we discuss in the

Underwriters section of this prospectus, and may not be indicative of the market price of our common stock after this offering. Consequently, you may not be able to sell shares of our common stock at prices equal to or greater than the price paid by you in this offering.

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Purchasers of Common Stock in this Offering will Experience Immediate and Substantial Dilution of $ Per Share.

Based on an assumed initial public offering price of $ per share, purchasers of our common stock in this offering will experience an immediate and substantial dilution of $ per share in the pro forma as adjusted net tangible book value per share of common stock from the initial public offering price, and our pro forma as adjusted net tangible book value at December 31, 2010 after giving effect to this offering would be $ per share. See Dilution for a complete description of the calculation of net tangible book value.

Our Intended Use of the Net Proceeds We Receive from this Offering is as Set Forth Under Use of Proceeds in this Prospectus, but Our Budgets May Change Throughout 2012 Depending on Oil and Natural Gas Prices, the Outcome of Our Drilling and Exploration Programs and Proposed Acquisitions.

As we discuss in the Use of Proceeds section in this prospectus, we intend to use the net proceeds we receive from this offering and from any exercise of the underwriters over-allotment option to repay the then outstanding borrowings under our credit agreement and to fund a portion of our anticipated 2012 capital expenditure budget. To the extent we repay borrowings under our credit agreement, additional borrowings will be available to be used to fund our 2012 capital expenditure budget. However, we may determine to revise our 2012 capital expenditure budget based on the then current oil and natural gas prices and the outcome of our drilling programs. In addition, we may spend some of the net proceeds we receive from this offering or additional borrowings under our credit agreement to consummate acquisitions of interests and acreage not contemplated by our 2012 capital expenditure budget if we are presented with attractive acquisition opportunities. Management has broad discretion in applying the net proceeds we receive from this offering. Our shareholders may not agree with the manner in which our management chooses to allocate and spend the net proceeds we receive from this offering. The failure of management to apply these funds effectively will have a material adverse effect on our business, financial condition, results of operations and cash flows. Pending their use, we may invest our net proceeds from this offering in a manner that does not produce income or that loses value.

Because We Are a Relatively Small Company, 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, May Strain Our Resources, Increase Our Costs and Distract Management; and We May Be Unable to Comply with these Requirements in a Timely or Cost-Effective Manner.

As a public company with listed equity securities, we will need to comply with new laws, regulations and requirements, certain corporate governance provisions of the Sarbanes-Oxley Act of 2002, or Sarbanes-Oxley Act, related regulations of the SEC and the requirements of the NYSE, with which we are 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, which we cannot estimate accurately at this time. 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 and the Public Company Accounting Oversight Board;
- 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;

involve and retain to a greater degree outside counsel and accountants in the above activities;

establish an internal audit function; and

establish an investor relations function.

In addition, we also expect that being a public company subject to these rules and regulations may require us to accept less director and officer liability insurance coverage than we desire or to incur substantial costs to obtain 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.

Prior to the completion of this offering, we have been a private company and have 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 audit for the year ended December 31, 2010, our independent registered public accountants identified and communicated material weaknesses related to accounting for deferred income taxes, impairment of oil and natural gas properties, assessment of unproved and unevaluated properties and the administration of our stock plan. 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 on a timely basis.

We have begun the process of evaluating our internal control over financial reporting and will continue to work with our auditors to put into place new accounting process and control procedures to address the issues set forth above. However, we will not complete this process until well after this offering is completed. We cannot predict the outcome of this process at this time.

We are not currently required to comply with the SEC s rules implementing Section 404 of the Sarbanes-Oxley Act, and are therefore not required to make a formal assessment of the effectiveness of our internal control over financial reporting for that purpose. Upon becoming a public company, we will be required to comply with the SEC s rules implementing Section 302 of the Sarbanes-Oxley Act, which will 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 not be required to make our first assessment of our internal control over financial reporting until the year following the year that our first annual report is filed or required to be filed with the SEC. To comply with the requirements of being a public company, we will need to upgrade our systems, including information technology, implement additional financial and management controls, reporting systems and procedures and hire 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 until the year following the year that our first

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annual report is required to be filed with the SEC. Once they are required to do so, our independent registered public accountants may issue a report that is adverse in the event it is 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 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.

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, prohibition on the payment of dividends and the repurchase of shares of our common stock are imposed under our credit agreement. While these prohibitions exist, we are prohibited from the payment of dividends and the repurchase of shares of our common stock without a waiver from our lenders. 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 after this offering may never exceed the price paid by you in this offering.

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 after this offering, and the perception that these sales could occur may also depress the market price of our common stock. Based on shares outstanding at , 2012, upon completion of this offering, we will have outstanding approximately shares of common stock, and in addition to the shares sold in this offering, shares of common stock will be immediately freely tradable, without restriction, in the public market. The underwriters expect that of our shares, including all shares held by our officers, directors and selling shareholders (after taking into account the shares sold by the selling shareholders), will be subject to lock-up agreements that prohibit the disposition of those shares during the 180-day period beginning on the date of the final prospectus related to this offering, except with the prior written consent of RBC Capital Markets, LLC and subject to certain exceptions. We expect to obtain these agreements prior to the commencement of this offering. After the expiration of the 180-day restricted period, all of these shares may be sold in the public market in the United States, subject to prior registration in the United States, if required, or reliance upon an exemption from U.S. registration, including, in the case of shares held by affiliates or control persons, compliance with the volume restrictions of Rule 144.

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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 discussed in this prospectus lapse, the trading price of our common stock could decline significantly and could decline below the initial public offering price. 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.

As soon as practicable after this offering, we intend to file a registration statement with the SEC on Form S-8 providing for the registration of 4,739,500 shares of our common stock issuable or reserved for issuance under our 2003 Stock and Incentive Plan and our 2011 Long-Term Incentive Plan. Subject to the satisfaction of vesting conditions, the expiration of lockup agreements and certain restrictions on sales by affiliates, shares registered under a registration statement on Form S-8 will be available for resale immediately in the public market without restriction.

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, or will contain upon completion of this offering, 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. See Description of Capital Stock Business Combinations Under Texas Law.

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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.

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CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This prospectus contains forward-looking statements that are subject to a number of risks and uncertainties, many of which are beyond our control. All statements, other than statements of historical fact included in this prospectus, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs and cash flows, prospects, plans and objectives of management are forward-looking statements. When used in this prospectus, the words could, believe, anticipate, intend, estimate, expect, may, should, continue, project and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words.

Forward-looking statements may include statements about our:

- business strategy;
- reserves;
- technology;
- cash flows and liquidity;
- financial strategy, budget, projections and operating results;
- oil and natural gas realized prices;
- timing and amount of future production of oil and natural gas;
- availability of drilling and production equipment;
- availability of oil field labor;
- the amount, nature and timing of capital expenditures, including future exploration and development costs;
- availability and terms of capital;
- drilling of wells;
- competition and government regulations;

marketing of oil and natural gas;

exploitation projects or property acquisitions;

costs of exploiting and developing our properties and conducting other operations;

general economic conditions;

competition in the oil and natural gas industry;

effectiveness of our risk management and hedging activities;

environmental liabilities;

counterparty credit risk;

governmental regulation and taxation of the oil and natural gas industry;

developments in oil-producing and natural gas-producing countries;

uncertainty regarding our future operating results;

estimated future reserves and present value thereof; and

plans, objectives, expectations and intentions contained in this prospectus that are not historical.

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All forward-looking statements speak only at the date of this prospectus. You should not place undue reliance on these forward-looking statements. Although we believe that our plans, intentions and expectations reflected in or suggested by the forward-looking statements we make in this prospectus are reasonable, we can give no assurance that these plans, intentions or expectations will be achieved. We disclose important factors that could cause our actual results to differ materially from our expectations under Risk Factors and Management s Discussion and Analysis of Financial Condition and Results of Operations and elsewhere in this prospectus. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf. We do not undertake any obligation to update or revise publicly any forward-looking statements except as required by law, including the securities laws of the United States and the rules and regulations of the SEC.

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USE OF PROCEEDS

We will receive net proceeds of approximately $ million from the sale of the common stock offered by us, assuming an initial public offering price of $ per share (the midpoint of the price range set forth on the cover page of this prospectus) and after deducting estimated expenses of approximately $ million and estimated underwriting discounts and commissions of approximately $ million. If the underwriters over-allotment option is exercised in full, we estimate that our net proceeds will be approximately $ million. We will not receive any proceeds from the sale of shares of our common stock by the selling shareholders.

Initially, we intend to use the net proceeds we receive from this offering to repay the then outstanding borrowings under our credit agreement ($113.0 million outstanding, excluding $1.3 million in outstanding letters of credit, at December 30, 2011). Following the application of the net proceeds we receive from this offering, we will have approximately $98.7 million available for potential future borrowings under our credit agreement (after giving effect to outstanding letters of credit). We intend to use the remaining net proceeds from this offering, our cash from operations and available borrowings under our credit agreement to fund our 2012 capital expenditure requirements. Although we have no current plans or proposals, pending application of the portion of our net proceeds to fund our 2012 capital expenditure requirements, we may be presented with other opportunities for acquisitions of interests or acreage. In that case, we may decide to use a portion of the net proceeds to finance these acquisitions and use cash flows from operations or additional borrowings under our credit agreement to fund our 2012 capital expenditure requirements, when necessary.

We intend to use the following amounts of the net proceeds for the above uses:

Use of Net Proceeds	**Amount (in millions)**
Repayment of senior secured revolving credit agreement	$
Payment of a portion of 2012 capital expenditure requirements	
Total net proceeds	$

In December 2011, we amended and restated our senior secured revolving credit agreement. This amendment increased the maximum facility amount from $150 million to $400 million. Borrowings are limited to the lesser of $400 million or the borrowing base, which will be $100 million immediately following this offering. Comerica Bank serves as administrative agent of our credit agreement, which matures in December 2016. Our borrowings under the credit agreement bear interest at a variable rate of 3.25% plus a Eurodollar-based rate per annum, which equated to approximately 3.6% per annum at December 30, 2011. For more information regarding our amended and restated credit agreement, see Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Credit Agreement.

Borrowings under the credit agreement were incurred from December 2010 through December 2011 to finance acquisitions of acreage and ongoing drilling and completion operations. Upon consummation of this offering and application of the net proceeds we receive in the manner described above, we will have available borrowings under our credit agreement to finance our capital expenditure requirements. We anticipate that we may need to access future borrowings under our credit agreement within 60 to 90 days following completion of this offering to fund a portion of our 2012 capital expenditure requirements in excess of amounts available from our cash flows and the net proceeds of this offering.

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The selling shareholders will receive net proceeds of approximately $ million from their sale of shares of common stock in this offering after deducting estimated underwriting discounts and commissions. We will pay all expenses related to this offering, other than underwriting discounts and commissions related to the shares sold by the selling shareholders. See Principal and Selling Shareholders and Underwriters.

An increase or decrease in the initial public offering price of $1.00 per share of common stock would cause the net proceeds that we will receive from this offering, after deducting estimated expenses and underwriting discounts and commissions, to increase or decrease by approximately $ million.

While we expect to use the net proceeds from this offering in the manner described above, including for potential acquisitions of interests and/or acreage (although we have no current plans to do so), the ultimate amount of capital we will expend may fluctuate materially based on market conditions and our drilling results. Our future financial condition and liquidity will be impacted by, among other factors, our level of production of oil and natural gas and the prices we receive from the sale thereof, the outcome of our exploration and drilling programs, the number of commercially viable oil and natural gas discoveries made and the quantities of oil and natural gas discovered, the speed with which we can bring such discoveries to production, and the actual cost of exploration and development of our oil and natural gas assets. We intend to invest any net proceeds from this offering that exceed the pay off amount of our credit agreement as described above in U.S. treasury bonds or investment grade instruments until otherwise needed.

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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, limitations on the payment of dividends on our common stock are imposed under our credit agreement.

In addition, prior to consummation of this offering, the holders of our Class B common stock 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 accrue and are payable quarterly at the rate of $0.06-2/3 per share of Class B common stock outstanding. For the years ended December 31, 2010 and 2009, we declared dividends on our outstanding shares of Class B common stock totaling $274,853 in each year. For the nine months ended September 30, 2011, we declared dividends on our outstanding shares of Class B common stock totaling $206,140. Upon the automatic conversion of the outstanding shares of Class B common stock at the closing of this offering, the right of the holders of Class B common stock to dividends will terminate. Any accrued but unpaid dividends existing at the time of such conversion will be paid to the holders of the Class B common stock upon conversion.

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CAPITALIZATION

The following table sets forth our capitalization at September 30, 2011. Our capitalization is presented:

- on an actual basis; and

- on an as adjusted basis to give effect to this offering (assuming aggregate net proceeds of $137.0 million are received by us), the application of the estimated net proceeds to be received by us to repay then outstanding borrowings under our credit agreement ($113.0 million outstanding, excluding $1.3 million in outstanding letters of credit, at December 30, 2011), with the balance being added to cash and cash equivalents until it is used to fund capital requirements, the issuance of 285,000 shares of common stock by us to certain holders of stock options immediately prior to consummation of this offering in connection with the exercise of their stock options at an exercise price of $9.00 per share and the conversion of our Class B common stock into Class A common stock upon consummation of this offering.

You should read the following table in conjunction with Use of Proceeds, Selected Historical Consolidated and Other Financial Data, Management s Discussion and Analysis of Financial Condition and Results of Operations and our historical consolidated financial statements and related notes thereto appearing elsewhere in this prospectus.

	At September 30, 2011	
	Actual	**As Adjusted**
(In thousands except for shares)		
Cash and cash equivalents	$ 7,768	$
Certificates of deposit	2,085	
Debt:		
Short-term debt	25,000	
Long-term debt[(1)]	60,000	
Shareholders equity:		
Class A common stock, $0.01 par value, 80,000,000 shares authorized; 42,907,843 shares issued and 41,728,668 shares outstanding, actual; shares issued and shares outstanding, as adjusted	429	
Class B common stock, $0.01 par value, 2,000,000 shares authorized; 1,030,700 shares issued and outstanding, actual; zero shares issued and outstanding, as adjusted	10	
Additional paid-in capital	263,933	
Retained earnings	14,931	
Treasury stock, at cost, 1,179,175 shares	(10,765)	
Total shareholders equity	$ 268,538	$
Total capitalization	$ 328,538	$

(1) At December 30, 2011, the borrowing base under our credit agreement was $125.0 million, and we had $113.0 million in borrowings outstanding, excluding $1.3 million in outstanding letters of credit. Approximately $10.7 million remained available for additional borrowings. See Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Credit Agreement.

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DILUTION

Purchasers of the common stock in this offering will experience immediate and substantial dilution in the net tangible book value per share of the common stock for accounting purposes. Our net tangible book value at September 30, 2011 was approximately $269 million, or $6.28 per share of common stock. Pro forma net tangible book value per share is determined by dividing our pro forma tangible net worth (tangible assets less total liabilities) by the total number of outstanding shares of common stock that will be outstanding immediately prior to the closing of this offering.

After giving effect to the sale of the shares in this offering and further assuming the receipt of the estimated net proceeds to be received by us (after deducting estimated discounts and expenses of this offering), our adjusted pro forma net tangible book value at September 30, 2011 would have been approximately $ million, or $ per share. This represents an immediate increase in the net tangible book value of $ per share to our existing shareholders and an immediate dilution (i.e., the difference between the offering price and the adjusted pro forma net tangible book value after this offering) to new investors purchasing shares in this offering of $ per share. The following table illustrates the per share dilution to new investors purchasing shares in this offering:

Assumed initial public offering price per share	$
Pro forma net tangible book value per share at September 30, 2011	
Increase per share attributable to new investors in this offering	
As adjusted pro forma net tangible book value per share after giving effect to this offering	
Dilution in pro forma net tangible book value per share to new investors in this offering	$

The following table summarizes, on an as adjusted basis at September 30, 2011, the total number of shares of common stock owned by existing shareholders (assuming (i) the issuance by us of 285,000 shares of common stock to certain holders of stock options immediately prior to consummation of this offering in connection with the exercise of their stock options at an exercise price of $9.00 per share and (ii) the conversion of our Class B common stock as described under Description of Capital Stock) and to be owned by new investors, the total consideration paid, and the average price per share paid by our existing shareholders and to be paid by new investors in this offering at $, the midpoint of the range of the initial public offering prices set forth on the cover page of this prospectus, calculated before deduction of estimated underwriting discounts and commissions:

	Shares Acquired		Total Consideration		Average Price
	Number	Percent	Amount	Percent	per Share
Existing shareholders	42,759,368				
New investors					
Total		100%		100%	

(1) The number of shares disclosed for the existing shareholders includes shares being sold by the selling shareholders in this offering. The number of shares disclosed for the new investors does not include the shares being purchased by the new investors from the selling shareholders in this offering.

Apart from the information set forth in the tables above, assuming the underwriters over-allotment is exercised in full, sales by us in this offering will reduce the percentage of shares held by existing shareholders to % and will increase the number of shares held by new investors to , or % on an as adjusted pro forma basis at September 30, 2011.

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SELECTED HISTORICAL CONSOLIDATED AND OTHER FINANCIAL DATA

You should read the following selected financial data in conjunction with Corporate Reorganization, 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 prospectus. The financial information included in this prospectus may not be indicative of our future results of operations, financial position and cash flows.

The following selected financial information is summarized from our results of operations for the five-year period ended December 31, 2010 and selected consolidated balance sheet data at December 31, 2010, 2009, 2008, 2007 and 2006 and our results of operations for the nine months ended September 30, 2011 and 2010 and the consolidated balance sheet data at September 30, 2011 and 2010 and should be read in conjunction with the consolidated financial statements at the years ended December 31, 2010, 2009 and 2008 and the nine month periods ended September 30, 2011 and 2010, and the notes thereto included herewith.

	Year Ended December 31,					Nine Months Ended September 30,	
	2010	2009	2008	2007	2006	2011 (Unaudited)	2010 (Unaudited)
(In thousands)							
Statement of operations data:							
Revenues:							
Oil and natural gas revenues	$ 34,042	$ 19,039	$ 30,645	$ 13,988	$ 14,678	$ 52,009	$ 25,182
Realized gain (loss) on derivatives	5,299	7,625	(1,326)	213		4,237	2,988
Unrealized gain (loss) on derivatives	3,139	(2,375)	3,592	(211)		1,534	5,813
Total revenues	42,480	24,289	32,911	13,990	14,678	57,780	33,983
Expenses:							
Production taxes and marketing	1,982	1,077	1,639	779	896	4,801	1,235
Lease operating	5,284	4,725	4,667	3,099	3,075	5,639	3,801
Depletion, depreciation and amortization	15,596	10,743	12,127	7,889	10,950	22,578	10,931
Accretion of asset retirement obligations	155	137	92	70	55	158	107
Full-cost ceiling impairment		25,244	22,195		56,504	35,673	
General and administrative	9,702	7,115	8,252	5,189	5,407	9,395	6,793
Total expenses	32,719	49,041	48,972	17,026	76,887	78,244	22,867
Operating income (loss)	9,761	(24,752)	(16,061)	(3,036)	(62,209)	(20,464)	11,116
Other income (expense):							
Net gain (loss) on asset sales and inventory impairment	(224)	(379)	136,977				
Interest and other income	364	781	2,984	2,736	2,063	248	300
Interest expense	(3)					(461)	
Total other income (expense)	137	402	139,962	2,736	2,063	(213)	300
Net income (loss)	$ 6,377	$ (14,425)	$ 103,878	$ (300)	$ (60,146)	$ (13,725)	$ 7,373

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	At December 31, 2010	2009	2008	2007	2006	At September 30, 2011 Actual (Unaudited)	2011 As Adjusted(1) (Unaudited)	2010 (Unaudited)
(In thousands)								
Balance sheet data:								
Cash and cash equivalents	$ 21,060	$ 104,230	$ 150,768	$ 9,017	$ 43,183	$ 7,768	$ 31,768	$ 38,618
Certificates of deposit	2,349	15,675	20,782			2,085	2,085	7,429
Short-term investments				57,925				
Net property and equipment	303,880	142,078	125,261	105,814	63,062	350,279	350,279	227,052
Total assets	346,382	277,400	314,539	179,152	112,628	383,244	407,244	291,423
Current liabilities	30,097	8,868	35,475	5,541	5,878	50,102	25,102	19,396
Long term liabilities	34,408	4,210	2,059	1,568	878	64,604	4,604	8,125
Total shareholders equity	$ 281,877	$ 264,321	$ 277,005	$ 172,043	$ 105,872	$ 268,538	$ 405,538	$ 263,902

	Year Ended December 31, 2010	2009	2008	2007	2006	Nine Months Ended September 30, 2011 (Unaudited)	2010 (Unaudited)
(In thousands)							
Other financial data:							
Net cash provided by operating activities	$ 27,273	$ 1,791	$ 25,851	$ 7,881	$ 1,570	$ 34,443	$ 21,390
Net cash (used in) provided by investing activities	(147,334)	(49,415)	115,481	(108,296)	(49,501)	(107,772)	(78,718)
Oil and natural gas properties capital expenditures	(159,050)	(54,244)	(104,119)	(50,310)	(51,932)	(104,733)	(86,031)
Expenditures for other property and equipment	(1,610)	(307)	(3,012)	(1,300)	(3,127)	(3,303)	(934)
Net cash provided by (used in) financing activities	36,891	1,086	419	66,250	73,876	60,037	(8,284)
Adjusted EBITDA(2)	$ 23,635	$ 15,184	$ 18,411	$ 8,091	$ 7,582	$ 37,550	$ 17,133

(1) As adjusted to give effect to this offering (assuming aggregate net proceeds of $137.0 million are received by us), the application of the estimated net proceeds to be received by us to repay the then outstanding borrowings under our credit agreement ($113.0 million outstanding, excluding $1.3 million in outstanding letters of credit, at December 30, 2011), with the balance being added to cash and cash equivalents to fund capital requirements, the issuance of 285,000 shares of common stock by us to certain holders of stock options immediately prior to consummation of this offering in connection with the exercise of their stock options at an exercise price of $9.00 per share and the conversion of our Class B common stock into Class A common stock upon consummation of this offering.

(2) 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 Summary Financial, Reserves and Operating Data.

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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 prospectus. 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 the prospectus, 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, acquisition and production of oil and natural gas resources in the United States, with a particular emphasis on oil and natural gas shale plays and other unconventional resources. 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. These plays are a key part of our growth strategy, and we believe they currently represent two of the most active and economically viable unconventional resource plays in North America. We expect the majority of our near-term capital expenditures will focus on increasing our production and reserves from the Eagle Ford and Haynesville shale plays as we seek to capitalize on the relative economics of each play. In addition to these primary operating areas, we have significant 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 213 wells through September 30, 2011, including 83 Haynesville and six Eagle Ford wells. At September 30, 2011, based on the reserves audit by our independent reservoir engineers, we had 161.8 Bcfe of estimated proved reserves with a PV-10 of $155.2 million and a Standardized Measure of $143.4 million. At September 30, 2011, 35% of our estimated proved reserves were proved developed reserves and 96% of our estimated proved reserves were natural gas. We grew our average daily production by 162% from 9.0 MMcfe per day from the year ended December 31, 2008 to 23.6 MMcfe per day for the year ended December 31, 2010. As a result of initial production from several wells that were completed in 2011, our average daily production for the nine months ended September 30, 2011 was approximately 42.5 MMcfe per day.

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

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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. Because we produce more natural gas than oil at the present time and expect to continue to do so in the near term, we will face more risks associated with fluctuations in the price of natural gas. Since one of our current business strategies is to focus on increasing our oil and liquids production, we will face increased risk in the future associated with fluctuations in the price of oil.

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.

One of the biggest challenges we face in the development of our Eagle Ford and Haynesville shale acreage is associated with service costs, and particularly in the Eagle Ford play, pipeline infrastructure and the shortage of stimulation equipment and service dates necessary to stimulate these wells. Due to the increased activity in these areas, service costs have continued to rise and the availability of completion crews has decreased. We believe that reducing drilling and particularly completion costs will be essential to the successful development and profitability of the Eagle Ford and Haynesville shale plays. 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 believe that our general and administrative expenses will increase in connection with the completion of this offering 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 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 following the completion of this offering 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 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.

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Unrealized gain (loss) on derivatives. We use commodity derivative financial instruments to mitigate our exposure to fluctuations in 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,			Nine Months Ended September 30,	
	2010	2009	2008	2011 (Unaudited)	2010 (Unaudited)
Operating Results:					
Revenues (in thousands):					
Oil	$ 2,506	$ 1,719	$ 3,653	$ 10,468	$ 1,831
Natural gas	31,535	17,320	26,992	41,541	23,351
Total oil and natural gas revenues	34,042	19,039	30,645	52,009	25,182
Realized gain (loss) on derivatives	5,299	7,625	(1,326)	4,237	2,988
Unrealized gain (loss) on derivatives	3,139	(2,375)	3,592	1,534	5,813
Total revenues	$ 42,480	$ 24,289	$ 32,911	$ 57,780	$ 33,983
Net Production Volumes:					
Oil (MBbls)	33	30	37	113	24
Natural gas (Bcf)	8.4	4.8	3.1	10.9	5.9
Total natural gas equivalents (Bcfe)	8.6	5.0	3.3	11.6	6.0
Average net daily production (MMcfe/d)	23.6	13.7	9.0	42.5	22.0
Average Sales Prices:					
Oil (per Bbl)	$ 76.39	$ 57.72	$ 98.59	$ 92.71	$ 74.59
Natural gas, with realized derivatives (per Mcf)	$ 4.38	$ 5.17	$ 8.32	$ 4.19	$ 4.49
Natural gas, without realized derivatives (per Mcf)	$ 3.75	$ 3.59	$ 8.75	$ 3.80	$ 3.98

Nine Months Ended September 30, 2011 Compared to Nine Months Ended September 30, 2010

Oil and natural gas revenues. Our oil and natural gas revenues increased by $26.8 million to $52.0 million, or an increase of about 107%, for the nine months ended September 30, 2011, as compared to the nine months ended September 30, 2010. This doubling in oil and natural gas revenues corresponds with an increase of about 93% in our oil and natural gas production to 11.6 Bcfe for the nine months ended September 30, 2011 from 6.0 Bcfe for the nine months ended September 30, 2010. This increased production was primarily due to drilling operations in the Haynesville shale, but also reflects initial production from our first two operated wells in the Eagle Ford shale. A portion of the increased oil and natural gas revenues was also attributable to the approximate five-fold increase in our oil production for the nine months ended September 30, 2011 as compared to the nine months ended September 30, 2010, as well as to the increase of about $18.00 per Bbl in the average price we received for this oil production during the nine months ended September 30, 2011 as compared to the same period in 2010.

Realized gain (loss) on derivatives. Our realized gain on derivatives increased by approximately $1.2 million to $4.2 million for the nine months ended September 30, 2011 from $3.0 million for the nine months ended September 30, 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 $0.91 per MMBtu hedged on all of our open natural gas costless collar contracts during the nine months ended September 30, 2011 as compared to $0.68 per MMBtu hedged on all of our open natural gas costless collar contracts during the nine months ended September 30, 2010.

Unrealized gain (loss) on derivatives. Our unrealized gain on derivatives was $1.5 million for the nine months ended September 30, 2011, compared to an unrealized gain of $5.8 million for the nine months ended September 30, 2010. During the period from December 31, 2010 to September 30, 2011, the net fair value of our open natural gas costless collar contracts increased from $4.1 million to $5.6 million, resulting in an unrealized gain on derivatives of $1.5 million for the nine months ended September 30, 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 the first nine months of 2011 as compared to the comparable period in 2010, as well as an increase in the total number of our open contracts at September 30, 2011 as compared to December 31, 2010. During the period from December 31, 2009 to September 30, 2010, the net fair value of our open natural gas costless collar contracts increased from $1.0 million to $6.8 million, resulting in an unrealized gain on derivatives of $5.8 million for the nine months ended September 30, 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 $3.1 million for the year ended December 31, 2010, compared to an unrealized loss of $2.4 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 $1.0 million to $4.1 million, resulting in an unrealized gain on derivatives of $3.1 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. During the period from December 31, 2008 to December 31, 2009, the net fair value of our open natural gas costless collar contracts decreased from $3.4 million to $1.0 million, resulting in an unrealized loss on derivatives of $2.4 million for the year ended December 31, 2009. This decrease in the net fair value of our open natural gas costless collar contracts was due primarily to an approximate $2.00 per MMBtu decrease in the average floor price of our open contracts at December 31, 2009 as compared with December 31, 2008.

Year Ended December 31, 2009 as Compared to Year Ended December 31, 2008

Oil and natural gas revenues. Our oil and natural gas revenues decreased $11.6 million to $19.0 million, or a decrease of about 38%, during the year ended December 31, 2009 as compared to the year ended December 31, 2008. Although we increased our production by 51% from 3.3 Bcfe in 2008 to 5.0 Bcfe in 2009, the oil and natural gas revenues of approximately $5.8 million generated by these increased production volumes did not fully offset the $17.4 million decrease in oil and natural gas revenues attributable to a sharp decline in the prices we received for both oil and natural gas in 2009 as compared with 2008. For the year ended December 31, 2009, we received an average natural gas price of $3.59 per Mcf and an average oil price of $57.72 per Bbl as compared to an average natural gas price of $8.75 per Mcf and an average oil price of $98.59 per Bbl for the year ended December 31, 2008. Our increased production during this period was due primarily to drilling operations in the Haynesville shale.

Realized gain (loss) on derivatives. Our realized gain on derivatives increased approximately $8.9 million to $7.6 million during the year ended December 31, 2009 from a loss of $1.3 million during the year ended December 31, 2008. Natural gas futures prices closed above the price ceiling of many of our open natural gas costless collar contracts during the first half of 2008, and, as a result, we were required to pay the counterparty at settlement. Natural gas prices declined sharply beginning in August 2008 and continued to decline throughout much of 2009, and as a result, natural gas prices closed below the price floor of many of our open costless collar contracts during almost all of 2009. As a result, we received cash from the counterparty at settlement and our realized gain on derivatives increased significantly.

Unrealized gain (loss) on derivatives. Our unrealized loss on derivatives was $2.4 million for the year ended December 31, 2009 as compared to an unrealized gain of $3.6 million for the year ended December 31, 2008. During the period from December 31, 2008 to December 31, 2009, the net fair value of our open natural gas costless collar contracts decreased from $3.4 million to $1.0 million, resulting in an unrealized loss on derivatives of $2.4 million for the year ended December 31, 2009. This decrease in the net fair value of our open natural gas costless collar contracts was due primarily to an approximate $2.00 per MMBtu decrease in the average floor price of our open contracts at December 31, 2009 as compared with December 31, 2008. During the period from December 31, 2007 to December 31, 2008, the net fair value of our open natural gas costless collar contracts increased from a liability of $0.2 million to $3.4 million, resulting in an unrealized gain on derivatives of $3.6 million for the year ended December 31, 2008. This increase in the net fair value of our open natural gas costless collar contracts was due to a decrease in natural gas prices and an increase in the volume of natural gas hedged at December 31, 2008 as compared with December 31, 2007.

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 differences between the book and tax basis of 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 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.

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 fees and annual agency fees as interest expense.

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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,			Nine Months Ended September 30,	
	2010	2009	2008	2011 (Unaudited)	2010 (Unaudited)
(In thousands, except expenses per Mcfe)					
Expenses:					
Production taxes and marketing	$ 1,982	$ 1,077	$ 1,639	$ 4,801	$ 1,235
Lease operating	5,284	4,725	4,667	5,639	3,801
Depletion, depreciation and amortization	15,596	10,743	12,127	22,578	10,931
Accretion of asset retirement obligations	155	137	91	158	107
Full-cost ceiling impairment		25,244	22,195	35,673	
General and administrative	9,702	7,115	8,252	9,395	6,793
Total expenses	32,719	49,041	48,972	78,244	22,867
Operating income (loss)	9,761	(24,752)	(16,061)	(20,464)	11,116
Other income (expense):					
Net gain (loss) on asset sales and inventory impairment	(224)	(379)	136,978		
Interest and other income	364	781	2,984	248	300
Interest expense	(3)			(461)	
Total other income (expense)	137	402	139,962	(213)	300
Income (loss) before income taxes	9,898	(24,350)	123,901	(20,677)	11,416
Total income tax provision (benefit)	3,521	(9,925)	20,023	(6,952)	4,043
Net income (loss)	$ 6,377	$ (14,425)	$ 103,878	$ (13,725)	$ 7,373
Expenses per Mcfe:					
Production taxes and marketing	$ 0.23	$ 0.22	$ 0.50	$ 0.41	$ 0.21
Lease operating	$ 0.61	$ 0.94	$ 1.41	$ 0.49	$ 0.63
Depletion, depreciation and amortization	$ 1.81	$ 2.15	$ 3.67	$ 1.95	$ 1.82
General and administrative	$ 1.13	$ 1.42	$ 2.50	$ 0.81	$ 1.13

Nine Months Ended September 30, 2011 Compared to Nine Months Ended September 30, 2010

Production taxes and marketing. Our production taxes and marketing expenses increased by $3.6 million to $4.8 million, or an increase of approximately 289% for the nine months ended September 30, 2011, as compared to the nine months ended September 30, 2010. The increase in our production taxes and marketing expenses reflects the increases in both our oil and natural gas production and revenues by 93% and 107%, respectively, during the nine months ended September 30, 2011 as compared to the nine months ended September 30, 2010. The majority of this increase was due to higher marketing, transportation and compression charges on non-operated Haynesville shale production in the first nine months of 2011 as compared to the same period in 2010. Some of this increase was also due to recently completed Haynesville shale wells, several of which were turned to sales or produced their first significant production volumes during the first nine months of 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 September 30, 2011. Thus, we have paid and/or accrued for the associated production taxes on these wells during the first nine months of 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 nine months ended September 30, 2011 was due to production taxes paid on initial production from our first two operated Eagle Ford shale wells in south Texas.

Lease operating expenses. Our lease operating expenses increased by $1.8 million to $5.6 million, or an increase of about 48%, for the nine months ended September 30, 2011 as compared to the nine months ended September 30, 2010. During these respective periods, however, our oil and natural gas production increased 93% from 6.0 Bcfe to 11.6 Bcfe. As a result, our lease operating expenses per unit of production decreased by 22% to $0.49 per Mcfe for the nine months ended September 30, 2011 as compared to $0.63 per Mcfe for the nine months ended September 30, 2010. During the first nine months of 2011, 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 $11.6 million to $22.6 million, or an increase of about 107%, for the nine months ended September 30, 2011 as compared to the nine months ended September 30, 2010. The increase in our depletion, depreciation and amortization expenses was due primarily to an increase of approximately 93% in our oil and natural gas production from 6.0 Bcfe to 11.6 Bcfe during the respective time periods. A portion of this increase was also due to a 7% increase in our depletion, depreciation and amortization expenses on a unit-of-production basis from $1.82 per Mcfe for the nine months ended September 30, 2010 to $1.95 per Mcfe for the nine months ended September 30, 2011. This increase reflects increases in drilling and completion costs for wells drilled to the Haynesville shale during the past year. This increase was also due, in part, to higher finding and development costs on a per Mcfe basis associated with our initial wells drilled and completed in the Eagle Ford shale.

Accretion of asset retirement obligations. Our accretion of asset retirement obligations expenses increased by approximately $51,000 to approximately $158,000, or an increase of about 48%, for the nine months ended September 30, 2011 as compared to the nine months ended September 30, 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. 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 September 30, 2010. At 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 also reflected in our expenses for the nine months ended September 30, 2011.

General and administrative. Our general and administrative expenses increased by $2.6 million to $9.4 million, or an increase of about 38%, for the nine months ended September 30, 2011 as compared to the nine months ended September 30, 2010. The increase in our general and administrative expenses was due

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primarily to increased cash and non-cash compensation expenses and increased accounting and legal expenses for the nine months ended September 30, 2011 as compared to the nine months ended September 30, 2010. As a result of our increased oil and natural gas production, however, our general and administrative expenses decreased by 28% on a unit-of-production basis to $0.81 per Mcfe for the nine months ended September 30, 2011 as compared to $1.13 per Mcfe for the nine months ended September 30, 2010.

Net gain (loss) on asset sales and inventory impairment. We did not incur gains or losses on asset sales and inventory impairment during the nine months ended September 30, 2011 or during the nine months ended September 30, 2010.

Interest expense. At September 30, 2011, we had borrowed $85.0 million under our credit agreement, including a term loan of $25.0 million, to finance a portion of our working capital requirements and capital expenditures and had incurred total interest expense of approximately $1.2 million. We capitalized $756,000 of our interest expense on certain qualifying projects for the nine months ended September 30, 2011 and expensed the remaining $461,000 to operations. At September 30, 2011, the interest rate on the term loan was approximately 5.3% and the interest rate on the other outstanding borrowings was approximately 2.2%. We had no borrowings under the credit agreement at September 30, 2010 and, as a result, we incurred no interest expense for the nine months ended September 30, 2010.

Interest and other income. Our interest and other income decreased by approximately $52,000 to approximately $248,000, or a decrease of about 17%, for the nine months ended September 30, 2011 as compared to the nine months ended September 30, 2010. The decrease in our interest and other income was due primarily to a significant 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 $9.9 million at September 30, 2011 from approximately $46.0 million at September 30, 2010, as we used cash 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 $7.0 million for the nine months ended September 30, 2011 as compared to a total income tax provision of approximately $4.0 million for the nine months ended September 30, 2010. The total income tax benefit for the nine months ended September 30, 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. At 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. This deferred income tax credit exceeded our deferred tax liabilities at March 31, 2011, and as a result, we reduced our net deferred tax liabilities by $6.9 million and established a net valuation allowance due to uncertainties regarding the future realization of our deferred tax assets. We retained a net valuation allowance in the amount of approximately $0.8 million at September 30, 2011. We will continue to assess the valuation allowance on a periodic basis and to the extent we determine that the allowance is no longer required, the tax benefit of the remaining deferred tax assets will be recognized in the future. The total income tax provision for the nine months ended September 30, 2010 included a deferred income tax provision of approximately $5.4 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 nine months ended September 30, 2010, the deferred income tax provision was consistent with our

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income before income taxes, which included approximately $5.8 million in unrealized hedging gains. We had a net loss for the nine months ended September 30, 2011, and our effective tax rate for the nine months ended September 30, 2010 was 35.42%.

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 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 have continued to decrease as our Haynesville production has 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.

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.

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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 $173,690. We also recognized an impairment of $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 $0.4 million.

Interest expense. In December 2010, we borrowed $25.0 million under our revolving credit agreement to finance a portion of our working capital requirements and capital expenditures. At December 31, 2010, the interest rate on the outstanding borrowings was approximately 1.6%. 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.

Year Ended December 31, 2009 Compared to Year Ended December 31, 2008

Production taxes and marketing. Our production taxes and marketing expenses decreased approximately $0.6 million to $1.1 million, or a decrease of about 34%, during the year ended December 31, 2009 as compared to the year ended December 31, 2008. The decrease in our production taxes and marketing expenses was due primarily to a decrease of about 38% in our oil and natural gas revenues to $19.0 million for the year ended December 31, 2009 from $30.6 million for the year ended December 31, 2008. Because our production increased 51% from 3.3 Bcfe to 5.0 Bcfe during these respective periods, our production taxes and marketing expenses on a unit-of-production basis decreased to $0.22 per Mcfe during the year ended December 31, 2009 from $0.50 per Mcfe for the year ended December 31, 2008.

Lease operating expenses. Our lease operating expenses increased approximately $58,000 to $4.7 million, or an increase of about 1%, during the year ended December 31, 2009 as compared to the year ended December 31, 2008. During these respective periods, however, our production increased 51%, from 3.3 Bcfe to 5.0 Bcfe. We began producing natural gas from the Haynesville shale in June 2009 and additional Haynesville wells began producing with corresponding sales during the latter part of 2009. Despite this production growth in 2009, our lease operating expenses increased only slightly due to the fact that the unit lease operating costs associated with the Haynesville production were much less than those associated with the Cotton Valley production, which made up the majority of our production during 2008. This is primarily due to the greater salt water disposal costs associated with the Cotton Valley production. As a result, our unit lease operating costs decreased to $0.94 per Mcfe during the year ended December 31, 2009 from $1.41 per Mcfe during the year ended December 31, 2008, or a decrease of about 33%.

Depletion, depreciation and amortization. Our depletion, depreciation and amortization expenses decreased $1.4 million to $10.7 million, or a decrease of about 11%, during the year ended December 31, 2009 as compared to the year ended December 31, 2008. Our depletion, depreciation and amortization expenses decreased despite the fact that our production grew 51% from 3.3 Bcfe to 5.0 Bcfe during these respective periods. This decrease was due to the fact that the finding and development costs associated with our Haynesville shale production have been less than the finding and development costs associated with our production from the Cotton Valley and other formations. As a result, our depletion, depreciation and amortization expenses on a unit-of-production basis decreased to $2.15 per Mcfe for the year ended December 31, 2009 from $3.67 per Mcfe for the year ended December 31, 2008.

Accretion of asset retirement obligations. Our accretion of asset retirement obligations expenses increased approximately $46,000 to $137,000, or an increase of about 51%, during the year ended December 31, 2009 as compared to the year ended December 31, 2008. 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.

Full-cost ceiling impairment. 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. At December 31, 2008, the net capitalized costs of our oil and natural gas properties less related deferred income taxes exceeded the cost center ceiling by $14.3 million. As a result, we recorded an impairment charge of $22.2 million to the net capitalized costs of our oil and natural gas properties and a deferred income tax credit of $7.9 million. A corresponding charge of $22.2 million was also recorded in the consolidated statement of operations for the year ended December 31, 2008.

General and administrative. Our general and administrative expenses decreased by $1.1 million to $7.1 million, or a decrease of about 14%, for the year ended December 31, 2009 as compared to the year ended December 31, 2008. The decrease in our general and administrative expenses was due primarily to a decrease in compensation expenses between the respective periods. In July 2008, we paid a special cash performance bonus of approximately $1.7 million to eligible employees in recognition of the significant increase in the value of our assets resulting from the sale of a portion of our Haynesville shale exploration and development rights in northwest Louisiana. We did not make any such extraordinary cash bonus payments to our employees during the year ended December 31, 2009; however, the decrease in bonus compensation in 2009 as compared to 2008 was offset to some degree by additional compensation expense associated with the hiring of new staff and the general increase in the costs to conduct our business during the year ended December 31, 2009. As a result of our increased oil and natural gas production, however, our general and administrative expenses decreased by 43% on a unit-of-production basis to $1.42 per Mcfe for the year ended December 31, 2009 as compared to $2.50 per Mcfe for the year ended December 31, 2008.

Net gain (loss) on asset sales and inventory impairment. Our net gain (loss) on asset sales and inventory impairment decreased by $137.4 million to a net loss of approximately $0.4 million for the year ended December 31, 2009 as compared to a net gain of $137.0 million for the year ended December 31, 2008. During the year ended December 31, 2009, we recognized impairments to drilling rig parts and tubular goods held in inventory and sold rod parts held in inventory, recognizing a net loss of $0.4 million. During the year ended December 31, 2008, we sold a portion of our Haynesville shale exploration and development rights in northwest Louisiana to a subsidiary of Chesapeake Energy Corporation and recognized a gain of $137.0 million on the sale. We also recognized a loss of about $44,000 on the sale of tubular goods held in inventory during 2008.

Interest expense. We had no borrowings under our credit agreement in 2009 or 2008. As a result, we had no interest expense for the years ended December 31, 2009 and 2008.

Interest and other income. Our interest and other income expenses decreased by $2.2 million to $0.8 million, or a decrease of about 74%, for the year ended December 31, 2009 as compared to the year ended December 31, 2008. The decrease in our interest and other income expenses 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 respective periods. Our cash and cash equivalents and certificates of deposit decreased to $119.9 million at December 31, 2009 from $171.6 million at December 31, 2008, as we used cash during this period primarily to acquire additional leasehold acreage in the core area of the Haynesville shale play in northwest Louisiana and to fund our operated and non-operated drilling and completion activities.

Total income tax provision (benefit). We recorded a total income tax benefit of approximately $9.9 million for the year ended December 31, 2009 as compared to a total income tax provision of approximately $20.0 million for the year ended December 31, 2008. 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. For the year ended December 31, 2008, we recorded a current income tax provision of approximately $10.4 million which reflects the payment of $9.4 million in U.S. federal alternative minimum tax and approximately $1.0 million in income tax to the state of Louisiana. The alternative minimum tax payment resulted from exhausting our alternative minimum tax net operating loss due to the gain realized from the sale of certain of our Haynesville shale assets. See Business Other Significant Prior Events. We also recorded a deferred income tax provision of approximately $9.6 million, reflecting both the large increase in our income before income taxes for the year, partially offset by the deferred income tax benefit attributable to the full-cost ceiling impairment recorded in 2008, and by the reversal of a previously established valuation allowance of approximately $24.7 million. We had a net loss for the year ended December 31, 2009, and our effective tax rate for the year ended December 31, 2008 was 16.16%.

Liquidity and Capital Resources

Our primary sources of liquidity to date have been 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. See Business Other Significant Prior Events. Our primary use of capital has been for the acquisition, exploration and development of oil and natural gas properties. We continually evaluate potential capital sources, including equity and debt financings, 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 September 30, 2011, we had cash and certificates of deposits totaling approximately $9.9 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 million to $400 million. Borrowings are limited to the lesser of $400 million or the borrowing base. At December 30, 2011, the borrowing base was $125 million, and we had $113.0 million of outstanding indebtedness, excluding $1.3 million in outstanding letters of credit. Following this offering and after application of the net proceeds, our borrowing base will be reduced to $100 million. The new amended credit agreement matures in December 2016. Our borrowings bear interest at a variable rate of 3.25% plus a Eurodollar-based rate per annum, which equated to approximately 3.6% per annum at December 30, 2011.

We previously entered into the credit agreement in March 2008 and amended and restated it for the first time in May 2011. At September 30, 2011, the agreement provided for a borrowing base of $80.0 million and our outstanding revolving borrowings under the credit agreement bore interest at the rate of 2.2%. In addition to our revolving borrowings under the credit agreement, in May 2011, we borrowed $25 million in 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. The term loan bore interest at an annual rate of 5% plus a Eurodollar-based rate, which equated to approximately 5.3% at September 30, 2011. This term loan was refinanced by revolving borrowings under the amended and restated credit agreement in December 2011. For more information regarding our amended and restated credit agreement, see Credit Agreement.

We actively review acquisition opportunities on an ongoing basis. While we believe the net proceeds we receive from this offering, 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. We anticipate that we may need to access future borrowings under our credit agreement within 60 to 90 days following completion of this offering to fund a portion of our 2012 capital expenditure requirements in excess of amounts available from our cash flows and the net proceeds of this offering. See Use of Proceeds.

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Our cash flows for the years ended December 31, 2010, 2009 and 2008 and the nine months ended September 30, 2011 and 2010, are presented below:

	Year Ended December 31,			Nine Months Ended September 30,	
	2010	2009	2008	2011	2010
(In thousands)				(Unaudited)	(Unaudited)
Net cash provided by operating activities	$ 27,273	$ 1,791	$ 25,851	$ 34,443	$ 21,390
Net cash provided by (used in) investing activities	(147,334)	(49,415)	115,481	(107,772)	(78,718)
Net cash provided by (used in) financing activities	36,891	1,086	419	60,037	(8,284)
Net change in cash and cash equivalents	$ (83,170)	$ (46,538)	$ 141,751	$ (13,292)	$ (65,612)

Cash Flows Provided by Operating Activities

Net cash provided by operating activities increased by $13.0 million to $34.4 million for the nine months ended September 30, 2011 as compared to net cash provided by operating activities of $21.4 million for the nine months ended September 30, 2010. Net cash provided by oil and natural gas operations increased significantly to $37.1 million for the nine months ended September 30, 2011 from $18.5 million for the nine months ended September 30, 2010. This increase reflects primarily the 93% increase in our oil and natural gas production to 11.6 Bcfe from 6.0 Bcfe between the respective periods. This increase in cash flows provided by oil and natural gas operations was offset partially by changes in our operating assets and liabilities totaling approximately $5.6 million between September 30, 2010 and September 30, 2011. Our accounts payable and accrued liabilities increased to approximately $21.4 million at September 30, 2011 from approximately $15.2 million at September 30, 2010 due to our increased operating activity in south Texas. Our accounts receivable increased to $14.1 million at September 30, 2011 as compared to $7.5 million at September 30, 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.

Net cash provided by operating activities decreased by $24.1 million to $1.8 million for the year ended December 31, 2009 from $25.9 million for the year ended December 31, 2008. Although our production increased to 5.0 Bcfe for the year ended December 31, 2009 from 3.3 Bcfe for the year ended December 31, 2008, the average prices we received for oil and natural gas declined sharply between the respective periods. Our accounts payable and accrued liabilities were approximately $7.3 million at December 31, 2009 as we were drilling and/or completing only one operated horizontal Haynesville shale well at that time. Our accounts payable and accrued liabilities were approximately $25.2 million at December 31, 2008 as we were drilling and/or completing both operated vertical Cotton Valley wells and our first operated horizontal wells in the Haynesville shale play 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

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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. 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 Provided by (Used in) Investing Activities

Net cash used in investing activities increased by $29.1 million to $107.8 million for the nine months ended September 30, 2011 from $78.7 million for the nine months ended September 30, 2010. This increase in net cash used in investing activities reflected primarily an increase of $18.7 million in our oil and natural gas properties capital expenditures for the nine months ended September 30, 2011 as compared to the nine months ended September 30, 2010. The increased oil and natural gas properties capital expenditures for the nine months ended September 30, 2011 were primarily due to increased expenditures associated with our operated and non-operated drilling and completion activities in the Eagle Ford and Haynesville plays and our acreage acquisition in Karnes, DeWitt, Wilson and Gonzales Counties, Texas, as compared to the nine months ended September 30, 2010.

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 $104.1 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 are 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.

Net cash used in investing activities was $49.4 million for the year ended December 31, 2009 as compared to net cash provided by investing activities of $115.5 million for the year ended December 31, 2008. This decrease of $164.9 million in net cash provided by investing activities between the respective periods reflects primarily the proceeds received from the sale of a portion of our Haynesville rights in northwest Louisiana to a subsidiary of Chesapeake Energy Corporation in 2008. In addition, our oil and natural gas properties capital expenditures decreased by $49.9 million between the two periods owing to a decrease in our operated drilling activity and related capital expenditures in 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 Overview.

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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 (Used in) Financing Activities

Net cash provided by financing activities was $60.0 million for the nine months ended September 30, 2011 as compared to net cash used in financing activities of $8.3 million for the nine months ended September 30, 2010. The net cash provided by financing activities for the nine months ended September 30, 2011 was due almost entirely to additional borrowings of $60.0 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 addition, 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. The net cash used in financing activities of $8.3 million for the nine months ended September 30, 2010 reflected primarily our repurchase of 1,000,000 shares of Class A common stock in April 2010 at $9.00 per share for a total of $9.0 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 for 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.

Net cash provided by financing activities was $1.1 million for the year ended December 31, 2009 as compared to $0.4 million for the year ended December 31, 2008. 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, at $5.00 per share 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. For the year ended December 31, 2008, the most significant financing activities were the periodic exercise of stock options for which we received aggregate net proceeds of approximately $1.0 million.

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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 certain of MRC Energy Company s wholly owned subsidiaries. In addition, all obligations under the credit agreement are guaranteed by Matador Resources Company, the parent corporation.

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 on 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 30, 2011, the borrowing base was $125.0 million. After repayment of the then outstanding borrowings under our credit agreement with the net proceeds of this offering, the borrowing base will be reduced to $100.0 million until any subsequent redetermination of the borrowing base under the agreement. Both we and the lenders may each request an unscheduled redetermination of the borrowing base twice during the first year of the credit agreement and once during any 12-month period thereafter. 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. Except as set forth in the following sentence, 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, however, our outstanding borrowings under the credit agreement exceed $100.0 million on the earlier of December 31, 2012 or the date on which we inform the lenders that the borrowing base is equal to $100.0 million, then we will be required to immediately repay such excess amount.

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 plus (iii) an amount from 0.75% to 2.25% 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 1.00 minus the maximum rate during such interest calculation period at which Comerica Bank is required to maintain reserves on Euro-currency Liabilities (as defined in Regulation D of the Board of Governors of the Federal Reserve System), plus (ii) an amount from 1.75% to 3.25% 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. An unused facility fee of 0.375% to 0.50%, depending on the unused portion of the borrowing base, is paid quarterly in arrears.

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, 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.

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Our credit agreement contains various covenants that limit our ability to take certain actions, including, but not limited to, the following:

- incur indebtedness;
- enter into commodity hedging agreements;
- declare or pay dividends, distributions or redemptions;
- merge or consolidate; 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 credit agreement 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.

We had no borrowings under the credit agreement at December 31, 2009 and 2008. 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%. We had an additional $325,000 in letters of credit secured by certificates of deposit at Comerica Bank at December 31, 2010.

We believe that we were in compliance with the terms of our credit agreement and with all our bank covenants at December 31, 2010, 2009 and 2008. We obtained a written extension from Comerica Bank until July 15, 2011 to comply with a covenant under the credit agreement requiring submission of audited financial statements within 120 days of the prior year end and the submission of quarterly financial statements within 45 days of the prior quarter end. We submitted both sets of financial statements to Comerica Bank prior to this deadline.

At September 30, 2011, the borrowing base available for revolving borrowings was $80.0 million, and we had $60.0 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 $18.7 million available for additional borrowings. At September 30, 2011, our outstanding revolving borrowings bore interest at the rate of approximately 2.2%. 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 bore interest at an annual rate of 5% plus a Eurodollar-based rate, which equated to approximately

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5.3% at September 30, 2011, and while any principal and interest under the term loan was outstanding, the revolving borrowings under the credit agreement bore interest at the maximum annual rate of 1.875% plus a Eurodollar-based rate which equated to approximately 2.2% at September 30, 2011. The term loan was refinanced by borrowings under the amended and restated credit agreement in December 2011. At December 30, 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, excluding $1.3 million in outstanding letters of credit. We intend to repay all then outstanding borrowings under our credit agreement with the net proceeds we receive from this offering. We anticipate that we may need to access future borrowings under our credit agreement within 60 to 90 days following completion of this offering to fund a portion of our 2012 capital expenditure requirements in excess of amounts available from our cash flows and the net proceeds of this offering.

Obligations and Commitments

We had the following material contractual obligations and commitments at September 30, 2011 except as indicated:

	Payments Due by Period				
(in thousands)	Total	Less Than 1 Year	1 -3 Years	3 -5 Years	More Than 5 Years
Contractual Obligations:					
Revolving credit borrowings and term loan, including letters of credit[1]	$ 86,263	$ 26,263	$ 60,000	$	$
Office lease	6,243	144	1,150	1,186	3,763
Non-operated drilling commitments[2]	1,700	1,700			
Drilling rig contracts[3]	5,100	5,100			
Geological and geophysical contracts[4]	310	310			
Employee bonuses	1,240		1,240		
Asset retirement obligations	4,305	332	461	957	2,555
Total contractual cash obligations	$ 105,161	$ 33,849	$ 62,851	$ 2,143	$ 6,318

(1) At September 30, 2011, we had $60.0 million in revolving borrowings outstanding under our credit agreement, approximately $1.3 million in outstanding letters of credit issued pursuant to the credit agreement and $25.0 million outstanding under the term loan. The term loan was scheduled to mature on December 31, 2011, and our borrowings under our credit agreement were scheduled to mature in March 2013. All such amounts are now included as revolving borrowings under our credit agreement. 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. We incurred $28.0 million in additional borrowings in November and December 2011 under our credit agreement to fund certain capital expenditures.

(2) At September 30, 2011, we had outstanding commitments to participate in the drilling and completion of various non-operated wells in the Haynesville shale play. Our working interest in these wells varies from 0.03% to 0.4%, and most of these wells were in progress at September 30, 2011. If all these wells are drilled and completed, we estimate that we will have a minimum outstanding aggregate capital commitment for our participation in these wells of approximately $1.7 million at September 30, 2011, which we expect to incur within the next 12 months.

(3) At September 30, 2011, we had entered into two drilling rig contracts to explore and develop our Eagle Ford acreage in south Texas. The first rig began drilling operations on our acreage in September 2011 and the second rig began drilling operations on our acreage in November 2011. Both contracts are for a term of six months. Should we elect to terminate both contracts and if the drilling contractor were unable to secure work for both rigs or if the drilling contractor were unable to secure work for 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 for either or both rigs. Our maximum outstanding aggregate capital commitment on these contracts was approximately $5.1 million as of September 30, 2011.

(4) Includes fees pending for two 3-D seismic acquisition projects across our Eagle Ford acreage in south Texas and for core analysis to be provided by a division of Core Laboratories, LP.

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.

Basis of Presentation

The consolidated financial statements include the accounts of Matador Resources Company and its four wholly owned subsidiaries, Matador Production Company, Longwood Gathering and Disposal Systems GP, Inc., MRC Permian Company and MRC Rockies Company, as well as the accounts of Longwood Gathering and Disposal Systems, LP (our consolidated financial statements for the years ended December 31, 2010, 2009 and 2008 reflect our organizational structure prior to the consummation of the holding company merger; see Corporate Reorganization). Our consolidated financial statements have been prepared in accordance with GAAP. Our operations are conducted in one segment, generally referred to as the exploration and production industry. All significant intercompany balances and transactions have been eliminated in consolidation.

Pursuant to the terms of the corporate reorganization that was completed on August 9, 2011, Matador Resources Company changed its corporate name to MRC Energy Company and Matador Holdco, Inc. changed its corporate name to Matador Resources Company. As a part of this reorganization, MRC Energy Company became a wholly owned subsidiary of Matador Resources Company. Our unaudited condensed consolidated financial statements at September 30, 2011 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.

Use of Estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements. The preparation of our financial statements requires us 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. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. While we believe our 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 and assumptions used in preparation of our consolidated financial statements.

Our consolidated financial statements are based on a number of significant estimates. These include estimates of oil and natural gas revenues, accrued assets and liabilities, stock-based compensation, valuation of derivative financial instruments 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. Our oil and natural gas reserves estimates, which are inherently imprecise and based upon many factors beyond our control, are prepared by our engineering staff in accordance with guidelines established by the SEC and then audited for their reasonableness by independent petroleum engineers, except for certain interim periods as noted.

Accounts Receivable

We sell our oil and natural gas production to various purchasers. Due to the nature of the markets for oil and natural gas, we do not believe that the loss of any one purchaser would significantly impact operations. In addition, we may participate with industry partners in the drilling, completion and operation of oil and natural gas wells. Substantially all of our accounts receivable are due from either purchasers of oil and natural gas or participants in oil and natural gas wells for which we serve as the operator. Accounts receivable are due within 30 to 45 days of the production or billing date and are stated at amounts due from purchasers and industry partners.

We review our need for an allowance for doubtful accounts on a periodic basis, and determine 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 we operate and the debtor s ability to pay its obligations, among other things. We have no allowance for doubtful accounts related to our accounts receivable for any reporting period presented.

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 differences between the book and tax basis of 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. In 2009, the SEC provided new guidelines for estimating and reporting oil and natural gas reserves. Under these new guidelines, the commodity prices used to estimate oil and natural gas reserves were changed from last-day-of-the-year prices to an unweighted, arithmetic average of first-day-of-the-month prices for the previous 12-month period.

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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.

Asset Retirement Obligations

We recognize 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, our future asset retirement obligations relate to future costs associated with plugging and abandonment of our 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 our estimate or if federal or state regulators enact new plugging and abandonment requirements. At the time of actual plugging and abandonment of our oil and natural gas wells, we include 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.

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 collars. 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 based on our counterparty s valuation model which we verify for its reasonableness with an independent third party valuation using observable, market-corroborated inputs.

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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

In 2003, our board of directors and shareholders approved the Matador Resources Company 2003 Stock and Incentive Plan, or the 2003 Plan. See Compensation of Named Executive Officers Stock Options. The persons eligible to receive awards under the 2003 Plan include our employees, directors, officers, consultants or advisors. The 2003 Plan is administered by our 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. In the absence of an established market for shares of our common stock as a private company, the board of directors determines the fair market value of our common stock for purposes of awards under the 2003 Plan. We typically use newly issued shares to satisfy option exercises or restricted share grants.

Our 2012 Long-Term Incentive Plan has been adopted, effective January 1, 2012. This plan permits the granting of long-term equity and cash incentive awards to our Named Executive Officers, key employees, consultants and non-employee directors. See Compensation of Named Executive Officers Long-Term Incentive Plan.

Non-qualified stock option expense is recognized in our consolidated statement of operations on the date of the grant. Incentive stock options vest over four years, and the associated compensation expense is recognized on a straight-line basis over the vesting period. 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 and at September 30, 2011, we measured and recognized the fair value of the liability associated with our outstanding stock options using an estimated fair value of our Class A common stock. On occasion, the board of directors grants restricted shares to eligible participants under the 2003 Plan. The fair value of these restricted stock awards are recognized based upon the fair value of our stock as determined by the board of directors on the date of the grant. Depending on the terms of the restricted share grant, the fair value of the award may be recognized on the date of grant in our consolidated statement of operations, or in the case of a restricted share award that vests over time, the fair value of the award is measured on the date of grant and recognized on a straight-line basis over the vesting period.

Income Taxes

We file 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 and 2010. The tax years open for examination by the state of Texas are 2008, 2009 and 2010. The tax years open for examination by the state of New Mexico are 2008, 2009 and 2010. The tax years open for examination by the state of Louisiana are 2007, 2008, 2009 and 2010. At December 30, 2011, our 2007, 2008 and 2009 income and franchise tax returns were under examination by the state of Louisiana. As a result of preliminary findings received by us from the state of Louisiana, we recorded an income tax refund of $45,636, a franchise tax assessment of $91,995 and an associated interest expense of $12,429 for the three and nine months ended September 30, 2011.

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, 2010, 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. At December 31, 2010, 2009 and 2008, we did not record any interest or penalties related to income tax.

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 prospectus. 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

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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

Subsequent Events. We incorporate the accounting and disclosure requirements for subsequent events in our financial statements. In accordance with GAAP, new terminology was introduced recently which defines the date through which management must evaluate subsequent events and lists the circumstances under which an entity must recognize and disclose events or transactions occurring after the balance sheet date. We adopted this guidance at December 31, 2009.

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, 2010 and 2009 and September 30, 2011 included herein.

Derivative Financial Instruments. At December 31, 2008, we adopted new guidance to provide qualitative disclosures about our objectives and strategies for using derivative financial instruments and to provide a tabular presentation of quantitative information for derivatives designated as hedges, hedged items and other derivatives. This new guidance was effective for annual financial periods beginning after November 15, 2008. As its only requirement is to enhance disclosures, the new guidance had no material impact on our consolidated financial statements.

Fair Value. In May 2011, the FASB issued Accounting Standards Update, or ASU, 2011-04, *Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS*, or ASU 2011-04. ASU 2011-04 amends Accounting Standards Codification, or ASC, 820, *Fair Value Measurements*, or ASC 820, 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.

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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. We do not expect the adoption of this new guidance to have a significant impact on our financial position, results of operations or cash flows.

In September 2006, the FASB issued authoritative guidance for using fair value to measure assets and liabilities. This guidance applies whenever other standards require or permit assets or liabilities to be measured at fair value, but it does not expand the use of fair value in any new circumstances. In February 2009, the FASB delayed the effective date by one year for non-financial assets and liabilities. We adopted this guidance effective January 1, 2008, but delayed guidance relating to non-financial assets and liabilities until January 1, 2009. The adoption of this guidance did not have a significant impact on our financial position, results of operations or cash flows.

In February 2007, the FASB issued authoritative guidance permitting entities to choose to measure certain financial instruments and other items at fair value. The objective is to improve financial reporting by providing entities with the opportunity to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. Unrealized gains and losses on any items for which the fair value measurement option is elected are to be reported in the consolidated statement of operations. We adopted this guidance at January 1, 2008. We elected not to measure any eligible items using the fair value option in accordance with this guidance, and therefore, it did not have an impact on our financial position, results of operations or cash flows.

Uncertainty in Income Taxes. At January 1, 2008, we adopted the accounting guidance related to accounting for uncertainty in income taxes which provides for the financial statement benefit of a tax position as being recognized 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. Following adoption, we evaluated all tax positions for which the statute of limitations remained open, and management believes that the material positions taken would more likely than not be sustained by examination. We do not expect any change in unrecognized tax benefits in the next 12 months.

Internal Controls and Procedures

Prior to the completion of this offering, we have been a private company and have 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 other supervisory resources with which to address our internal control over financial reporting. In connection with our audit for the year ended December 31, 2010, our independent registered public accountants identified and communicated material weaknesses related to accounting for deferred income taxes, impairment of oil and natural gas properties, assessment of unproved and unevaluated properties and the administration of our stock plan.

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A material weakness is a control deficiency, or a combination of control deficiencies, in internal control over financial reporting, such that there is reasonable possibility that a material misstatement of our annual or interim financial statements will not be prevented or detected on a timely basis.

We have begun the process of evaluating our internal control over financial reporting and will continue to work with our auditors to put into place new accounting process and control procedures to address the issues set forth above. However, we will not complete this process until well after this offering is completed. We cannot predict the outcome of this process at this time.

We are not currently required to comply with the SEC s rules implementing Section 404 of the Sarbanes-Oxley Act, and are therefore not required to make a formal assessment of the effectiveness of our internal control over financial reporting for that purpose. Upon becoming a public company, we will be required to comply with the SEC s rules implementing Section 302 of the Sarbanes-Oxley Act, which will 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 not be required to make our first assessment of our internal control over financial reporting until the year following the year that our first annual report is filed or required to be filed with the SEC. To comply with the requirements of being a public company, we will need to upgrade our systems, including information technology, implement additional financial and management controls, reporting systems and procedures and hire 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 until the year following the year that our first annual report is required to be filed with the SEC. Once it is required to do so, our independent registered public accounting firm may issue a report that is adverse in the event it is 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.

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. At December 31, 2010, 2009 and 2008 and at September 30, 2011, we used costless collar options to reduce the volatility of natural gas prices on a significant portion of our future expected natural gas production.

We record all derivative financial instruments at fair value. The fair value of our derivative financial instruments is determined based on our counterparty s valuation model which we verified for its reasonableness annually with an independent third party valuation using observable, market-corroborated

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inputs. Comerica Bank is the single counterparty for all of our derivative instruments. We have made no adjustments to the fair value amounts recognized on the balance sheet for these derivative instruments to account for the credit standing of Comerica Bank.

The following is a summary of our open natural gas costless collar contracts at November 30, 2011:

Commodity	Calculation Period		Notional Quantity (MMBtu/month)	Price Floor ($/MMBtu)	Price Ceiling ($/MMBtu)	Fair Value of Asset (thousands)
Natural Gas	01/01/2010	12/31/2011	50,000	5.25	8.10	$ 94
Natural Gas	01/01/2010	12/31/2011	50,000	5.50	7.65	107
Natural Gas	01/01/2010	12/31/2011	50,000	5.00	8.65	82
Natural Gas	01/01/2010	12/31/2011	50,000	5.50	7.70	107
Natural Gas	01/01/2011	12/31/2011	90,000	5.50	7.85	192
Natural Gas	07/01/2011	12/31/2012	300,000	4.50	5.60	3,392
Natural Gas	07/01/2011	07/31/2013	150,000	4.50	5.75	2,210
Natural Gas	01/01/2012	12/31/2012	150,000	4.25	6.17	1,200
Total						$ 7,384

All of our existing natural gas derivative contracts will expire at varying times during 2011, 2012 and 2013. In November and December 2011, we entered into various costless collar transactions to mitigate our exposure to oil price volatility for the first time. The following table is a summary of our open oil costless collar contracts at November 30, 2011.

Commodity	Calculation Period		Notional Quantity (Bbl/month)	Price Floor ($/Bbl)	Price Ceiling ($/Bbl)	Fair Value of Asset (thousands)
Oil	12/01/2011	12/31/2012	20,000	90.00	104.20	$ (346)
Oil	01/01/2013	12/31/2013	20,000	85.00	102.25	(220)
Total						$ (566)

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.

Effect of Recent Derivatives Legislation

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

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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 $60.0 million in revolving debt outstanding at September 30, 2011 at an interest rate of 1.875% plus a Eurodollar-based rate, which equated to approximately 2.2% per annum at September 30, 2011. 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 bore interest at an annual rate of 5% plus a Eurodollar-based rate, which equated to approximately 5.3% at September 30, 2011. The term loan was refinanced through revolving borrowings in December 2011 under our amended and restated credit agreement. Borrowings under our amended and restated credit agreement bear interest at a variable rate of 3.25% plus a Eurodollar-based rate per annum, which equated to approximately 3.6% per annum at December 30, 2011. If we incur any 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.

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, 2010, 2009 and 2008. 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 Overview. 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.

Off-Balance Sheet Arrangements

At December 31, 2010 and September 30, 2011, we did not have any off-balance sheet arrangements.

Changes in Accountants

Grant Thornton LLP, or Grant Thornton, performed audits of our consolidated financial statements for the fiscal years ended December 31, 2008 and 2009. Grant Thornton s reports did not contain an adverse opinion or disclaimer of opinion and were not qualified or modified as to uncertainty, audit scope or accounting principles.

On or about June 1, 2010, following the completion of Grant Thornton s audit of our financial statements for the year ended December 31, 2009, our Audit Committee determined not to renew Grant Thornton s engagement as our independent accountant. On October 28, 2010, our board of directors unanimously approved the appointment of Ernst & Young, LLP, or Ernst & Young, as our independent accountant commencing with work to be performed in relation to our nine month period ended September 30, 2010. We had no occasion in 2008 and 2009 and any subsequent interim period prior to October 28, 2010 upon which we consulted with Ernst & Young on any matters.

During the fiscal years ended December 31, 2008 and 2009, and the subsequent interim period through June 1, 2010, there were (i) no disagreements with Grant Thornton on any matter of accounting principles or practices, financial statement disclosure or auditing scope or procedure, which disagreement(s), if not resolved to Grant Thornton s satisfaction, would have caused Grant Thornton to make reference to the subject matter of the disagreement(s) in connection with its reports for such years, and (ii) no reportable events within the meaning set forth in Item 304(a)(1)(v) of Regulation S-K.

Prior to the completion of Ernst & Young s audit of our financial statements for the nine month period ended September 30, 2010, on or about February 28, 2011, we mutually agreed with Ernst & Young to terminate our relationship. The decision to discontinue the audit services of Ernst & Young was mutual and was approved by our Board of Directors and Audit Committee effective at February 28, 2011. From October 28, 2010 through February 28, 2011, there were (i) no disagreements with Ernst & Young on any matter of accounting principles or practices, financial statement disclosure or auditing scope or procedure, which disagreement(s), if not resolved to Ernst & Young s satisfaction, would have caused Ernst & Young to make reference to the subject matter of the disagreement(s) in connection with its report for the nine-month period ended September 30, 2010, and (ii) no reportable events within the meaning set forth in Item 304(a)(1)(v) of Regulation S-K.

Effective at February 28, 2011, our Audit Committee unanimously approved the reappointment of Grant Thornton as our independent accountant to audit our financial statements for the year ended December 31, 2010. Prior to our reengagement of Grant Thornton, we had discussions with Grant Thornton regarding whether they had the capacity, availability and desire to reengage as our auditor going forward. Prior to these reengagement discussions, during the period from approximately the middle of December 2010 through the end of January 2011, there were also discussions regarding the accounting for our outstanding stock options, specifically regarding the liability versus equity classification of the outstanding stock options, and our accounting for income taxes related to the calculation of deferred taxes related to our statutory depletion calculation in 2008 and 2009. Based on discussions held prior to our reengagement of Grant Thornton, it was concluded that the accounting treatment continued to be appropriate with no adjustments to the previously issued financial statements necessary. The aforesaid discussions did not address any accounting issues related to the fiscal year 2010. We had no occasion between June 1, 2010 and February 28, 2011 upon which we consulted with Grant Thornton on any other matters.

Both Grant Thornton and Ernst & Young have been provided with a copy of this disclosure and have furnished to us a letter addressed to the Securities and Exchange Commission stating that they agree with the statements about such firms contained herein.

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BUSINESS

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. These plays are a key part of our growth strategy, and we believe they currently represent two of the most active and economically viable unconventional resource plays in North America. We expect the majority of our near-term capital expenditures will focus on increasing our production and reserves from the Eagle Ford and Haynesville shale plays as we seek to capitalize on the relative economics of each play. 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 Joseph Wm. Foran, Chairman, President and CEO, and Scott E. King, Co-Founder and Vice President, Geophysics and New Ventures, with an initial equity investment of approximately $6.0 million. Shortly thereafter, investors contributed approximately $46.5 million to provide a total initial capitalization of approximately $52.5 million. Most of this initial capital was provided by the same institutional and individual investors who helped capitalize Mr. Foran s previous company, Matador Petroleum Corporation.

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.

With an average of more than 25 years of oil and natural gas industry experience, our management team has extensive expertise in exploring for and developing hydrocarbons in multiple U.S. basins. Members of our management team have participated in the assimilation of numerous lease positions and in the drilling and completion of hundreds of vertical and horizontal wells in unconventional resource plays.

Since our first well in 2004, we have drilled or participated in drilling 213 wells through September 30, 2011, including 83 Haynesville and six Eagle Ford wells. From December 31, 2008 through September 30, 2011, we grew our estimated proved reserves from 20.0 Bcfe to 161.8 Bcfe. At September 30, 2011, 35% of our estimated proved reserves were proved developed reserves and 96% of our estimated proved reserves were natural gas. We also grew our average daily production by approximately 162% from 9.0 MMcfe per day for the year ended December 31, 2008 to 23.6 MMcfe per day for the year ended December 31, 2010. In addition, as a result of production from new wells that were completed in 2011, our daily production for the nine months ended September 30, 2011 averaged approximately 42.5 MMcfe per day. We have achieved this growth while lowering operating costs (consisting of lease operating expenses and production taxes and marketing expenses) from $1.91 per Mcfe for the year ended December 31, 2008, to $0.90 per Mcfe for the nine months ended September 30, 2010, or a decrease of approximately 53%.

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The following table presents certain summary data for each of our operating areas as of and for the nine months ended September 30, 2011:

		Producing Wells		Total Identified Drilling Locations(1)		Estimated Net Proved Reserves		Avg. Daily
	Net Acreage	Gross	Net	Gross	Net	Bcfe(2)	% Developed	Production (MMcfe)
South Texas:								
Eagle Ford	28,906	5.0	3.4	197.0	157.1	8.4	51.0	3.2
Austin Chalk	14,849			16.0	16.0			
Area Total(3)	28,906	5.0	3.4	213.0	173.1	8.4	51.0	3.2
NW Louisiana/E Texas:								
Haynesville	14,705	83.0	10.6	545.0	103.9	136.6	25.4	32.1
Cotton Valley(4)	23,236	108.0	71.7	60.0	36.0	16.1	100.0	7.0
Area Total(5)	25,477	191.0	82.3	605.0	139.9	152.7	33.3	39.1
SW Wyoming, NE Utah, SE Idaho	135,862							
SE New Mexico, West Texas	7,519	13.0	5.7			0.7	100.0	0.2
Total	197,764	209.0	91.4	818.0	313.0	161.8	34.5	42.5

(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 September 30, 2011, these identified drilling locations included 2 gross and 2 net locations to which we have assigned proved undeveloped reserves in the Eagle Ford and 95 gross and 15 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 September 30, 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 September 30, 2011, our properties included approximately 52,000 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 (see Recent Developments). We have identified 197 gross locations and 157 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

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authorities and surface considerations, among others. At September 30, 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 September 30, 2011, these identified potential future drilling locations in the Eagle Ford shale play included 2 gross and 2 net locations to which we have assigned proved undeveloped reserves.

In addition, at September 30, 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, almost 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. Just 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 September 30, 2011, we have identified 545 gross locations and 104 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 545 gross locations identified for future drilling, 470 of these locations (53 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 September 30, 2011, these identified potential future drilling locations included 95 gross and 15 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. 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 213 gross wells we have drilled or participated in drilling, we drilled approximately half of these wells as the operator. At September 30, 2011, we were the operator for approximately 80% 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.

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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 (see Other Significant Prior Events Chesapeake Transaction) 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.

Our net proceeds from this offering, after repaying the then outstanding borrowings under our revolving credit agreement ($113.0 million at December 30, 2011, excluding $1.3 million in outstanding letters of credit) when taken together with our cash flows and future potential borrowings under our credit agreement, will be used to fund our 2012 capital expenditure requirements and for potential acquisitions of interests and acreage (none of which have been identified). We anticipate that we may need to access future borrowings under our credit agreement within 60 to 90 days following completion of this offering to fund a portion of our 2012 capital expenditure requirements in excess of amounts available from our cash flows and the net proceeds of this offering. See Use of Proceeds.

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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 considered to be exploration or development wells.

	2012 Anticipated Drilling						2012 Anticipated Capital Expenditure Budget (in millions)[2]		
	Gross Wells[1]			Net Wells[1]					
	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	2.5	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 September 30, 2011, just 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.

Business Strategies

Our goal is to increase shareholder value by building reserves, production and cash flows at an attractive return on invested capital. We plan to achieve our goal by executing the following strategies:

Focus Exploration and Development Activity on Our Eagle Ford and Haynesville Shale Assets.

We have established core acreage positions in the Eagle Ford and Haynesville shale plays, which we believe are two of the most active and economically viable shale plays in North America. Although we intend to allocate a portion of our 2012 capital expenditure budget to

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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. Since just 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 at September 30, 2011, we have the flexibility to develop our acreage in a disciplined manner in order to maximize the resource recovery from these assets. We believe the economics for development in these two areas are attractive at current commodity prices.

Identify, Evaluate and Exploit Oil Plays to Create a More Balanced Portfolio.
Although most of our current proved reserves are classified as natural gas, we have been evaluating various oil plays to find and execute upon opportunities that would fit well with our exploration and operating strategies. 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. We believe oil and liquids opportunities represent about 94% of our anticipated 2012 capital expenditure budget. We expect to continue to create and acquire additional prospects and opportunities for the exploration and production of oil and liquids.

Pursue Opportunistic Acquisitions.
We believe our management team s familiarity with our key operating areas and their contacts with the operators and mineral owners in those regions enable us to identify high-return opportunities at attractive prices. We actively pursue opportunities to acquire unproved and unevaluated acreage, drilling prospects and low-cost producing properties within our core areas of operations where we have operational control and can enhance value and performance. We view these acquisitions as an important component of our business strategy and intend to selectively make acquisitions on attractive terms that complement our growth and help us achieve economies of scale.

Maintain Our Financial Discipline.
As an operator, we leverage advanced technologies and integrate the knowledge, judgment and experience of our management and technical teams. We believe our team demonstrates financial discipline that is achieved by our approach to evaluating and analyzing prospects and prior drilling and completion results before allocating capital and is reflected in the improvements our team has attained on reducing unit costs. When we are not the operator, we proactively engage with the operators in an effort to ensure similar financial discipline. Additionally, we conduct our own internal geological and engineering studies on these prospects and provide input on the drilling, completion and operation of many of these non-operated wells pursuant to our agreements and relationships with the operators. Through these methods and practices, we believe we are well-positioned to control the expenses and timing of development and exploitation of our properties.

Maintain Proactive and Ongoing Relationships with Other Industry Participants.
We believe maintaining proactive and ongoing relationships with other industry operators and vendors enhances our understanding of the shale plays and allows us to leverage their expertise without having to commit substantial capital. We currently participate in various drilling activities with larger industry participants, including affiliates of Chesapeake Energy Corporation, EOG

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Resources, Inc., Royal Dutch Shell plc and others. We are also active participants in three industry shale consortia: the North American Gas Shale, Haynesville and Bossier Shale and Eagle Ford Shale consortia organized by Core Laboratories, LP. As active members in various professional societies, our staff and board members also regularly interact on a professional basis with other industry participants.

Competitive Strengths

We believe our prior success is, and our future performance will be, directly related to the following combination of strengths that will enable us to implement our strategies:

High Quality Asset Base in Attractive Areas.
We have key acreage positions in active areas of the Eagle Ford and Haynesville shale plays. We believe our assets in these plays are characterized by low geological risk and similar repeatable drilling opportunities that we expect will result in a predictable production growth profile. The commodity mix of our production and reserves is expected to become more balanced as a result of our planned activities on our Eagle Ford and Austin Chalk acreage, which is located in oil and liquids prone areas of the plays. In addition to the Haynesville shale, our east Texas and north Louisiana assets have multiple, recognized geologic horizons, including the Middle Bossier shale, Cotton Valley and Hosston (Travis Peak) formations. We also believe there is additional resource potential in our oil and natural gas prospects in southeast New Mexico and west Texas, along with our natural gas prospects in southwest Wyoming and adjacent areas in Utah and Idaho.

Large, Multi-year, Development Drilling Inventory.
Within our northwest Louisiana/east Texas and south Texas regions, we have identified 818 gross and 313 net drilling locations, including 197 gross and 157 net locations in the Eagle Ford shale play and 545 gross and 104 net locations in the Haynesville shale play. At September 30, 2011, these identified drilling locations included 2 gross and 2 net locations to which we have assigned proved undeveloped reserves in the Eagle Ford shale play and 95 gross and 15 net locations to which we have assigned proved undeveloped reserves in the Haynesville shale play. We have identified 28 gross and 26 net locations in the Eagle Ford shale play and 25 gross and 2 net locations in the Haynesville shale play that we expect to drill in 2012, the completion of which would represent approximately 14% and 5% of our identified gross drilling locations in these two areas at September 30, 2011, respectively. Additionally, we expect to identify and develop additional locations across our broad exploration portfolio as we evaluate our Cotton Valley, Austin Chalk, Meade Peak and Delaware and Midland Basin assets. We believe our multi-year, identified drilling inventory and exploration portfolio provide visible near-term growth in our production and reserves, and highlight the long-term resource potential across our asset base.

Financial Flexibility to Fund Expansion.
Historically, we have maintained financial flexibility by obtaining capital through shareholder investments and our operational cash flows while maintaining low levels of indebtedness, which has allowed us to take advantage of acquisition opportunities as they arise. Upon the completion of this offering and the repayment of the then outstanding borrowings under our credit agreement ($113.0 million outstanding, excluding $1.3 million in outstanding letters of credit, at December 30, 2011), we expect to have at least $ million in cash, cash equivalents and certificates of deposit and at least $98.7 million available for borrowings under our credit agreement after giving effect to outstanding letters of credit. Excluding any possible acquisitions, we expect to maintain our current

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financial flexibility by funding our entire 2012 capital expenditure budget through the net proceeds we receive from this offering, together with our cash flows and future potential borrowings under our credit agreement. We anticipate that we may need to access future borrowings under our credit agreement within 60 to 90 days following completion of this offering to fund a portion of our 2012 capital expenditure requirements in excess of amounts available from our cash flows and the net proceeds of this offering. Our availability of capital as described above will also allow us to maintain our competitiveness in seeking to acquire additional oil and natural gas properties as opportunities arise. A strong balance sheet and interest savings should also reduce unit costs and increase profitability. In addition, since a large portion of our Eagle Ford and Haynesville acreage was held by production at September 30, 2011, we have the financial flexibility to allocate our capital when we believe it is economical and justified.

Experienced and Incentivized Management, Technical Team and Board.
Our management and technical teams possess extensive oil and natural gas expertise with an average of over 25 years of relevant industry experience from companies such as Matador Petroleum Corporation, S. A. Holditch & Associates, Inc., Schlumberger Limited, Conoco and ARCO, and we believe they have a demonstrated record of growth and financial discipline over many years. The management team has experience in drilling and completing hundreds of vertical and horizontal wells in unconventional resource plays, including the Cotton Valley, Bossier, Wilcox/Vicksburg, Austin Chalk, Haynesville and Eagle Ford plays. Our management team s experience is complemented by a strong technical team with deep knowledge of advanced geophysical, drilling and completion technologies who are active members of their professional societies. Additionally, we have a group of board members and special advisors with considerable experience and expertise in the oil and natural gas industry and in managing other successful enterprises who provide insight and perspective regarding our business and the evaluation, exploration, engineering and development of our prospects. In addition to its considerable experience, our management team currently owns and will continue to own a significant direct ownership interest in us immediately following the completion of this offering. We believe our management team s direct ownership interest, as well as their ability to increase their holdings over time through our long-term incentive plan, aligns management s interests with those of our shareholders.

Extensive Geologic, Engineering and Operational Experience in Unconventional Reservoir Plays.
The individuals on our technical team are highly experienced in analyzing unconventional reservoir plays and in horizontal drilling, completion and production operations in a number of geographic areas. Our geologists have extensive experience in analyzing unconventional reservoir plays throughout the United States, including our principal areas of interest, by using the latest imaging technology, such as 2-D and 3-D seismic interpretation, and petrophysical analysis. In addition, our technical team has been directly involved in over 26 different horizontal well drilling and/or operations programs in both onshore and offshore formations located in the United States and abroad. Our team s diverse and broad horizontal drilling experience includes most, if not all, techniques used in modern day drilling. Additionally, our team has in-depth experience with various horizontal completion techniques and their applications in various unconventional plays. We intend to leverage our team s geological expertise and horizontal drilling and completion experience to develop and exploit our large, multi-year development drilling inventory.

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Multi-Disciplined Approach to New Opportunities.
Our process for evaluating and developing new oil and natural gas prospects is a result of what we believe is an organizational philosophy that is dedicated to a systematic, multi-disciplinary approach to new opportunities with an emphasis on incorporating petroleum systems, geosciences, technology and finance into the decision-making process. We recognize the importance of consulting multiple individuals in our organization across all disciplines and all levels of responsibility prior to making exploration, acquisition or development decisions and the formulation of key criteria for successful exploration and development projects in any given play to enhance our decision-making. We also conduct a post-completion review of our major decisions to determine what we did right and where we need to improve. At times, this approach results in a decision to accelerate our drilling program or expand our positions in certain areas. Other times, this approach results in a decision to mitigate risk associated with our exploration and development programs by sharing operational risks and costs with other industry participants or exiting an area altogether. We believe this multi-disciplined approach underpins our track record of value creation and represents the best way to deliver consistent, year-over-year results to our shareholders.

Recent Developments

In December 2011, we amended and restated our senior secured revolving credit agreement. This amendment increased the maximum facility amount from $150 million to $400 million. Borrowings are limited to the lesser of $400 million or the borrowing base, which will be $100 million immediately following this offering.

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. We are the operator and have a 100% working interest in these three wells.

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 and began producing to sales in late December 2011. We are the operator of this well and paid 100% of the costs to drill and complete the well. We will receive 85% of the revenues attributable to the working interest in the well until we have recovered all of our acquisition, drilling and completion costs, after which time, our partner will receive 50% of the revenues attributable to the working interest in the well and we and our partner will each maintain a 50% working interest in the well.

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.

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In March 2011, first sales of natural gas began from our Williams 17 H#1 well, located in what we believe to be the core area of the Haynesville shale play in northwest Louisiana. We began producing this well at a constrained rate of about 10.0 MMcf of natural gas. During November 2011, this well produced at an average daily rate of 4.5 MMcf of natural gas per day, and through November 30, 2011, had produced approximately 1.7 Bcf of natural gas. We are the operator and have a 100% working interest and a favorable 87.5% net revenue interest in this well.

In February 2011, we completed our third operated Eagle Ford horizontal well, the Affleck #1H, in eastern Dimmit County, Texas. This well tested at approximately 415 Bbls of oil and 5.4 MMcf of natural gas per day during an initial flow test. During November 2011, this well produced at an average daily rate of 0.9 MMcf of natural gas and 70 Bbls of oil per day. We are the operator and have a 100% working interest in this well.

In January 2011, we completed a private placement offering of 1,922,199 shares of our Class A common stock at $11.00 per share for an aggregate amount of $21,144,189.

In January 2011, we completed our second operated Eagle Ford horizontal well, the Martin Ranch #1H, in northeastern LaSalle County, Texas. 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 November 2011, the well produced at an average daily rate of approximately 520 Bbls of oil and 0.6 MMcf of natural gas per day, and through November 30, 2011, had produced a total of approximately 111,000 Bbls of oil and 135 MMcf of natural gas. We are the operator and have a 100% working interest in this well.

In January 2011, first sales of oil and natural gas began from our first operated Eagle Ford horizontal well, the JCM Jr. Minerals #1H, in southern LaSalle County, at approximately 3.4 MMcf of natural gas and 135 Bbls of condensate per day. During November 2011, the well produced at an average daily rate of approximately 0.6 MMcf of natural gas and 12 Bbls of condensate per day, and through November 30, 2011, had produced a total of approximately 416 MMcf of natural gas and 10,900 Bbls of condensate. We are the operator and have a 100% working interest in this well.

In January 2011, we completed our first horizontal Cotton Valley well, the Tigner Walker H#1-Alt., in DeSoto Parish, Louisiana. First sales of natural gas from this well began in late January at approximately 4.6 MMcf of natural gas per day. During November 2011, the well produced at an average daily rate of approximately 1.9 MMcf of natural gas per day, and through November 30, 2011, had produced a total of approximately 900 MMcf of natural gas. We are the operator and have a 100% working interest in this well subject to a reversionary interest at payout.

On December 31, 2010, first sales of natural gas began from our L.A. Wildlife H#1 Alt. horizontal well, located in what we believe to be the core area of the Haynesville shale play in northwest Louisiana. We began producing this well at a constrained rate of about 10.0 MMcf of natural gas per day. During November 2011, the well produced at an average daily rate of approximately 10.0 MMcf of natural gas per day, and through November 30, 2011, had produced a total of approximately 3.2 Bcf of natural gas. We are the operator and have a 95% working interest in this well.

Other Significant Prior Events

Chesapeake Transaction

In July 2008, we consummated a transaction with a subsidiary of Chesapeake Energy Corporation for the sale of the deep rights underlying the acreage in our Elm Grove/Caspiana properties in southern Caddo

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Parish, Louisiana. We retained a carried interest in the initial well drilled in each of the sections in which we held leases. The deep rights were below the depth of any producing wells previously drilled by us and represented primarily the rights to explore for and develop the Haynesville shale underlying the Cotton Valley formation that was producing from the wells in our Elm Grove/Caspiana properties. The deep rights assigned to Chesapeake also included the Middle Bossier shale formation located between the base of the Cotton Valley formation and the top of the Haynesville shale. At the time of the Chesapeake transaction, we had no production from and no reserves assigned to the Haynesville shale play. We retained all rights to those depths above the base of the Cotton Valley formation, as well as all existing and future production and reserves from those formations. We reserved the right to be reassigned a proportionately reduced 25% working interest in each well drilled to the Haynesville shale by Chesapeake in each regular spacing unit established for the Haynesville shale which includes any of the rights we previously assigned to Chesapeake. Chesapeake agreed to carry us for all of the drilling and completion costs attributable to our interest in the first well drilled in each Haynesville spacing unit. In addition, we have the right to participate in subsequent wells drilled in each such spacing unit to the Haynesville shale on the basis of a proportionately reduced 25% non-carried working interest. We also reserved an overriding royalty interest in certain of the deep rights that were sold. At September 30, 2011, Chesapeake had paid all of our costs for drilling and completing 22 gross wells to the Haynesville shale, and we will have a carried interest in two additional gross wells that we expect will be completed before the end of 2011.

Stroud Transaction

In August 2009, we acquired from Stroud Exploration Company, L.L.C. and Stroud Petroleum, Inc. 95% of the deep rights below the base of the Cotton Valley formation underlying approximately 600 acres prospective for the Haynesville shale play to the immediate southwest of our Elm Grove/Caspiana acreage. We also took title to an existing vertical Haynesville well that was holding this acreage by production. We were obligated to reassign this vertical Haynesville well to Stroud following the completion of our first horizontal Haynesville well drilled on this acreage, at which time, Stroud would recomplete this vertical well in the Cotton Valley formation. On December 31, 2010, first sales of natural gas began from our L.A. Wildlife H #1 Alt. well, the first Haynesville horizontal well that we drilled on this acreage. We began producing this well at a constrained rate of about 10.0 MMcf of natural gas per day. During November 2011, the well produced at an average daily rate of approximately 10.0 MMcf of natural gas per day, and through November 30, 2011, had produced a total of approximately 3.2 Bcf of natural gas. We are the operator and have a 95% working interest in this well. In March 2011, we reassigned the vertical well to Stroud Exploration, reserving our rights below the base of the Cotton Valley formation.

Alliance Capital Participation Agreement

In May 2010, Roxanna Rocky Mountains, LLC and Alliance Capital Real Estate, Inc., an affiliate of AllianceBernstein L.P., entered into a participation agreement with our subsidiary, MRC Rockies Company, or MRC Rockies, regarding our Meade Peak shale prospect in southwest Wyoming and adjacent areas in Utah and Idaho. Under this agreement, Alliance Capital Real Estate agreed to pay up to $4.2 million of the cost to drill and core an initial test well in the Meade Peak shale and MRC Rockies agreed to pay up to an additional $630,000 to conclude such operations, if necessary. Each entity has agreed to pay 50% of any costs over $4.83 million. Roxanna Rocky Mountains elected to participate for up to a 10% working interest in the initial test well with the costs for its working interest to be carried by MRC Rockies. The 10% carried working interest participation by Roxanna Rocky Mountains in the initial test well was assigned from MRC Rockies 50% working interest in the leases within the 5,760 gross acres around the drill site.

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After receipt of the laboratory analysis of the whole core data from the initial test well, Alliance Capital Real Estate has the option to purchase up to a 50% working interest in the balance of all the leases in the prospect owned by MRC Rockies, to elect to drill and complete a second test well in the prospect at an agreed upon location or to elect not to proceed with further exploration of the prospect. If it elects to drill a second test well, it will pay up to $5.0 million of the costs to drill and complete, and to perform a production test on, the well. Each entity will pay 50% of any costs over $5.0 million. After drilling and production testing the second test well, Alliance Capital Real Estate has a second option to purchase up to a 50% working interest in the balance of the leases owned by MRC Rockies in the prospect. If Alliance Capital Real Estate elects to drill a second test well, Roxanna Rocky Mountains will have a similar option to participate for up to a 10% carried working interest in the second test well, which will be assigned from MRC Rockies 50% working interest in the leases within the 5,760 gross acres around the second drill site. If Roxanna Rocky Mountains elects not to participate in the second test well, Roxanna Rocky Mountains will relinquish all of its rights in the leases within the 5,760 gross acres around the second drill site, other than its reserved 2.5% overriding royalty interest.

Roxanna Rocky Mountains will bear and pay its proportional working interest share of all lease maintenance costs on these two test wells and has the right to participate and pay its proportional working interest share of all costs, on a well-by-well basis, in the drilling of any subsequent well proposed to be drilled on the prospect, except that Roxanna Rocky Mountains will not have the right to participate in the 5,760 acres around any second test well if it relinquishes its working interest in the leases in that area because it elects not to participate.

The parties also agreed to a large area of mutual interest for the prospect over a 10-year period. All operations in the prospect are governed by the terms of a joint operating agreement, with the parties bearing their respective working interest shares of the costs of any subsequent wells drilled on the prospect after the first two test wells. All working interests owned by the parties in the prospect will be subject to a proportionally reduced 2.5% overriding royalty interest owned by Roxanna Rocky Mountains in the leases. We will be the operator of the first two test wells, if both are drilled, and are the operator for the project under the joint operating agreement. We began drilling the initial test well, 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.

Acquisition of Bureau of Land Management Leases

In July 2010, we acquired approximately 850 gross and net acres in northwest Louisiana under two separate leases taken from the U.S. Bureau of Land Management that are primarily prospective for both the Haynesville and Middle Bossier shale plays. These leases have a ten-year primary term and a 12.5% lessor s royalty. As part of the acquisition, we acquired the rights to one complete, approximately 640-acre, section in which we have a 100% working interest and are the operator. In March 2011, first sales of natural gas began from our Williams 17 H#1 well located in this section which we believe is in the core area of the Haynesville shale play. We began producing this well at a constrained rate of about 10.0 MMcf of natural gas per day. During November 2011, the well produced at an average rate of approximately 4.5 MMcf of natural gas per day and, through November 30, 2011, had produced approximately 1.7 Bcf of natural gas. We are the operator and have a 100% working interest in this well.

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Glasscock Ranch Acquisition

On December 1, 2010, we acquired leasehold interests in approximately 8,900 gross and net acres in southeast Zavala County, Texas in the Eagle Ford shale play. We currently anticipate that this area of the Eagle Ford shale play will be predominantly prospective for oil and liquids. This acreage is also prospective for oil and liquids from other formations including the shallower Austin Chalk formation. We paid approximately $31.5 million to acquire this acreage. We own a 100% working interest in this property 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 consist 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

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 almost 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.

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Public 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 September 30, 2011, our aggregate leasehold interests consisted of approximately 52,000 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 almost 85% of our Eagle Ford acreage is prospective predominantly for oil and liquids. We expect to use a portion of the net proceeds we receive from this offering to explore and develop this acreage and to acquire additional acreage in south Texas as we seek to actively grow the oil and liquids component of our production and reserves. We currently own 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 own an approximate 21% working interest in approximately 23,000 gross acres in Atascosa County operated by EOG Resources, Inc. At September 30, 2011, approximately 80% of our Eagle Ford acreage is either held by production or not burdened by lease expirations before 2013.

At December 30, 2011, we had drilled and completed seven Eagle Ford wells on our operated properties, and all of these wells are producing to sales. At that date, 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 November 2011, the well produced at an average daily rate of approximately 0.6 MMcf of natural gas and 12 Bbls of condensate per day. 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 November 2011, the well produced at an average daily rate of approximately 520 Bbls of oil and 0.6 MMcf of natural gas per day. 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 November 2011, the well produced at an average daily rate of 0.9 MMcf of natural gas and 70 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

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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. As we are in the initial stages of our Eagle Ford operations, we have only a small amount of production and proved reserves attributable to this acreage.

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.

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.

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 September 30, 2011.

Northwest Louisiana and East Texas

Most of our current production and proved reserves is attributable to our acreage in northwest Louisiana and east Texas. For the nine months ended September 30, 2011 about 76% of our daily production, or 32.1 MMcfe per day, was produced from the Haynesville shale, with another 16%, or 7.0 MMcfe per day, produced from the Cotton Valley and other shallower formations in this area. At September 30, 2011, approximately 84% of our proved reserves, or 136.6 Bcfe, was attributable to the Haynesville shale underlying this acreage with another 10% of our proved reserves, or 16.1 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.

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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 three years, and the play is currently one of the most active and economically viable in the United States. 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.

We have 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 just over 5,500 net acres in what we believe is the core area of the play. Just 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 September 30, 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 November 2011, the well produced at an average daily rate of approximately 10.0 MMcf of natural gas per day, and through November 30, 2011, had produced a total of approximately 3.2 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 November 2011, this well produced at an average daily rate of 4.5 MMcf of natural gas per day and, through November 30, 2011, had produced approximately 1.7 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.

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The remainder of our acreage in the core area of the Haynesville shale play, about 4,300 net acres, is operated by other companies. As described above in Business Other Significant Prior Events Chesapeake Transaction, just over half of our non-operated Haynesville acreage in this area of the play results from our transaction with 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 September 30, 2011, we were participating in 90 non-operated Haynesville wells with Chesapeake and other operators, including producing wells and wells being drilled and completed at that time. At September 30, 2011, our production from these wells averaged approximately 19 MMcfe per day.

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, 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 porosites 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 November 2011, this well produced at an average daily rate of approximately 1.9 MMcf of natural gas per day and through November 30, 2011, had produced a total of approximately 900 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 our near-term capital expenditures primarily to exploration and development of our Eagle Ford shale acreage in south Texas and to additional exploration and development of our Haynesville acreage in northwest Louisiana.

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. We hold 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

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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.

Together with our joint venture partner, Roxanna Rocky Mountains, LLC, we have 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 5 to 10 years, has been acquired by us within the past four years, and we are the operator of this prospect. We have no production and no proved reserves attributable to this acreage at September 30, 2011.

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.

As described in Business Other Significant Prior Events Alliance Capital Participation Agreement, we are the operator of this prospect and 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.

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, 3D 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 are currently developing new oil and natural gas prospects in these basins. Most notably, we have identified potential drilling opportunities on our acreage, particularly in southeast New

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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 September 30, 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, we believe approximately 7,700 gross and 4,900 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, 2010, 2009 and 2008 and the nine months ended September 30, 2011 and 2010:

	Year Ended December 31,			Nine Months Ended September 30,	
	2010	**2009**	**2008**	**2011**	**2010**
Unaudited Production Data					
Net Production Volumes:					
Oil (MBbls)	33	30	37	113	24
Natural gas (Bcf)	8.4	4.8	3.1	10.9	5.9
Total natural gas equivalents (Bcfe)(1)	8.6	5.0	3.3	11.6	6.0
Average daily production (MMcfe/d)	23.6	13.7	9.0	42.5	22.0
Average Sales Prices:					
Oil (per Bbl)	$ 76.39	$ 57.72	$ 98.59	$ 92.71	$ 74.59
Natural gas, with realized derivatives (per Mcf)	$ 4.38	$ 5.17	$ 8.32	$ 4.19	$ 4.49
Natural gas, without realized derivatives (per Mcf)	$ 3.75	$ 3.59	$ 8.75	$ 3.80	$ 3.98
Operating Expenses (per Mcfe):					
Production taxes and marketing	$ 0.23	$ 0.22	$ 0.50	$ 0.41	$ 0.21
Lease operating	$ 0.61	$ 0.94	$ 1.41	$ 0.49	$ 0.63
Depletion, depreciation and amortization	$ 1.81	$ 2.15	$ 3.67	$ 1.95	$ 1.82
General and administrative	$ 1.13	$ 1.42	$ 2.50	$ 0.81	$ 1.13

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

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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			Total Net	Percentage of
	Gas (Mcf/d)	Oil (Bbls/d)	Gas Equivalent (Mcfe/d)	Production (MMcfe)	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 nine months ended September 30, 2011 from our primary operating areas:

	Average Net Daily Production			Total Net	Percentage of
	Gas (Mcf/d)	Oil (Bbls/d)	Gas Equivalent (Mcfe/d)	Production (MMcfe)	Total Net Production
South Texas:					
Eagle Ford	1,320	316	3,214	877	7.6
Austin Chalk(1)					
Area Total	1,320	316	3,214	877	7.6
NW Louisiana/E Texas:					
Haynesville	32,074	1	32,082	8,758	75.5
Cotton Valley(2)	6,538	70	6,958	1,900	16.4
Area Total	38,612	71	39,040	10,658	91.9
SW Wyoming, NE Utah, SE Idaho(1)					

SE New Mexico, West Texas	71	27	230	63	0.5
Total	40,003	414	42,484	11,598	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 11.6 Bcfe for the nine months ended September 30, 2011, was an increase of 93% over our total production of 6.0 Bcfe for the nine months ended September 30, 2010. This increased production is primarily due to drilling operations in the Haynesville shale, but also reflects initial production from our first two operated wells 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 is attributable to our drilling operations in the Haynesville shale

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play. Our 2009 total production of 5.0 Bcfe was a 51% increase over our total production of 3.3 Bcfe in 2008. Most of this increase is attributable to our drilling operations in the Haynesville shale. In addition, as a result of production from new wells that were completed in 2011, our daily production for the nine months ended September 30, 2011 averaged approximately 42.5 MMcfe per day.

Producing Wells

The following table sets forth information relating to producing wells at September 30, 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 11%. 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	3.0	1.4	5.0	3.4
Austin Chalk[1]						
Area Total	2.0	2.0	3.0	1.4	5.0	3.4
NW Louisiana/E Texas:						
Haynesville	83.0	10.6			83.0	10.6
Cotton Valley[2]	106.0	69.7	2.0	2.0	108.0	71.7
Area Total	189.0	80.3	2.0	2.0	191.0	82.3
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	192.0	82.9	17.0	8.5	209.0	91.4

(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.

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Estimated Proved Reserves

The following table sets forth our estimated proved oil and natural gas reserves at December 31, 2010, 2009 and 2008 and at September 30, 2011. The reserves estimates at December 31, 2008 presented in the table below were based on evaluations prepared by our engineering staff and have been audited for their reasonableness by LaRoche Petroleum Consultants, Ltd., independent reservoir engineers. The reserves estimates at December 31, 2010 and 2009 and at September 30, 2011 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 that were in effect at the time of the preparation of the reserves report. 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)			At September 30,
	2010	2009	2008	2011
Estimated Proved Reserves Data:(2)				
Estimated proved reserves:				
Natural gas (Bcf)	127.4	63.9	19.2	155.3
Oil (MBbls)	152	103	131	1,083
Total (Bcfe)	128.3	64.5	20.0	161.8
Estimated proved developed reserves:				
Natural gas (Bcf)	43.1	25.4	19.2	52.6
Oil (MBbls)	152	103	131	518
Total (Bcfe)	44.1	26.0	20.0	55.8
Percent developed	34.3%	40.3%	100.0%	34.5%
Estimated proved undeveloped reserves:				
Natural gas (Bcf)	84.3	38.6		102.7
Oil (MBbls)				565
Total (Bcfe)	84.3	38.6		106.0
PV-10(3) (in thousands)	$ 119,869	$ 70,359	$ 44,069	$ 155,217
Standardized Measure(4) (in thousands)	$ 111,077	$ 65,061	$ 43,254	$ 143,372

(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 index prices were $41.00 per Bbl for oil and $5.710 per MMBtu for natural gas at December 31, 2008. 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-month period from October 2010 to September 2011 were $91.00 per Bbl for oil and $4.158 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, 2008, 2009, and 2010 and at September 30, 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, 2008, 2009 and 2010 and at September 30, 2011 were, in thousands, $815, $5,298, $8,792 and $11,845 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.

In 2009, the SEC provided new guidelines for estimating and reporting oil and natural gas reserves. Included in these new guidelines were two important changes impacting our reserves estimates and value at December 31, 2009. First, proved undeveloped reserves can be assigned to well locations more than one offset location away from an existing well if supported by geologic continuity and existing technology. Second, under these new guidelines, oil and natural gas reserves at December 31, 2010 and 2009 and at September 30, 2011 were estimated using an unweighted, arithmetic average of the first-day-of-the-month oil and natural gas prices for the periods January through December 2009, January through December 2010, and October 2010 through September 2011, respectively, as further described in footnote two to the table above. Prior to these periods, SEC guidelines for estimating and reporting oil and natural gas reserves required using commodity prices at the date of the reserves estimate, or, in the cases above, at December 31, 2008, as further described in footnote two to the table above.

Our total proved oil and natural gas reserves increased from 128.3 Bcfe at December 31, 2010 to 161.8 Bcfe at September 30, 2011. Most of this increase is attributable to proved reserves added due to our drilling operations in the Haynesville shale play. The increase in proved oil reserves specifically from 152 MBbls at December 31, 2010 to 1,083 MBbls at September 30, 2011 is attributable to proved oil reserves added due to our drilling operations in the Eagle Ford shale play. Our proved reserves at September 30, 2011 were made up of approximately 96% natural gas and 4% oil. Our proved developed reserves increased from 44.1 Bcfe at December 31, 2010 to 55.8 Bcfe at September 30, 2011 due primarily to proved developed reserves added as a result of drilling operations in the Haynesville shale play. The increase in proved developed oil reserves specifically from 152 MBbls at December 31, 2010 to 518 MBbls at September 30, 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 106.0 Bcfe at September 30, 2011 due primarily to our drilling operations in the Haynesville shale. The increase in our proved undeveloped oil reserves specifically from zero to 565 MBbls at September 30, 2011 is attributable to our drilling operations in the Eagle Ford shale play. The net increase of 21.7 Bcfe in our proved undeveloped reserves from December 31, 2010 to September 30, 2011 is composed of (1) additions of 25.4 Bcfe to proved undeveloped reserves identified through drilling operations, less (2) the conversion of 1.4 Bcfe of proved undeveloped reserves to proved developed reserves, less (3) the downward revisions of proved undeveloped reserves by 2.3 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. We had no proved undeveloped reserves assigned to our properties at December 31, 2008, and hence, all of our proved undeveloped reserves have been added since that time. Thus, at September 30, 2011, we had no proved reserves in our estimates that remained undeveloped for five years or more following their initial booking.

Our total proved oil and natural gas reserves increased from 64.5 Bcfe at December 31, 2009 to 128.3 Bcfe at December 31, 2010. Taking into consideration the 8.6 Bcfe in production for the year ended December 31, 2010, we added approximately 72.4 Bcfe in proved reserves during 2010, which represents a gain of about 112%. Almost all of this increase is attributable to proved reserves added due to drilling operations in the Haynesville shale play. Our proved reserves at December 31, 2010 were made up of approximately 99% natural gas and 1% oil. Our proved developed reserves increased from 26.0 Bcfe at December 31, 2009 to 44.1 Bcfe at December 31, 2010 due primarily to proved developed reserves added

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as a result of drilling operations in the Haynesville shale play. Our proved undeveloped reserves increased from 38.6 Bcfe at December 31, 2009 to 84.3 Bcfe at December 31, 2010 due to drilling operations in the Haynesville shale play.

Our total proved oil and natural gas reserves increased from 20.0 Bcfe at December 31, 2008 to 64.5 Bcfe at December 31, 2009. Taking into consideration the 5.0 Bcfe in total production for 2009, we added approximately 49.5 Bcfe in proved reserves during 2009, which represents a gain of about 248%. The results from the Haynesville shale drilling program in our Elm Grove/Caspiana asset in northwest Louisiana during 2009 resulted in a significant increase in our total proved reserves at December 31, 2009. Our proved reserves at December 31, 2009 were made up of approximately 99% natural gas and 1% oil. Our proved developed reserves increased from 20.0 Bcfe at December 31, 2008 to 26.0 Bcfe at December 31, 2009, which is also attributable to the Haynesville shale drilling program in our Elm Grove/Caspiana asset during 2009. Our proved undeveloped reserves increased from zero at December 31, 2008 to 38.6 Bcfe at December 31, 2009 due entirely to proved undeveloped reserves added as a result of drilling operations in the Haynesville shale play during 2009.

The following table sets forth additional summary information by operating area with respect to our estimated proved reserves at September 30, 2011:

	Net Proved Reserves(1)				
	Oil (MBbls)	Gas (Bcf)	Gas Equivalent (Bcfe)	PV-10(2) (in millions)	Standardized Measure(3) (in millions)
South Texas:					
Eagle Ford	910	3.0	8.4	37.2	34.4
Austin Chalk(4)					
Area Total	910	3.0	8.4	37.2	34.4
NW Louisiana/E Texas:					
Haynesville		136.6	136.6	92.6	85.6
Cotton Valley(5)	81	15.6	16.1	23.2	21.4
Area Total	81	152.2	152.7	115.8	107.0
SW Wyoming, NE Utah, SE Idaho(4)					
SE New Mexico, West Texas	92	0.1	0.7	2.2	2.0
Total	1,083	155.3	161.8	155.2	143.4

(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 September 30, 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 September 30, 2011 were approximately $11.8 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 September 30, 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.

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Technology Used to Establish Reserves

Under the new 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 Reserves Manager reports directly to our Vice President Reservoir Engineering. 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, for the years ended December 31, 2010 and 2009 and for the nine month period ended September 30, 2011, we had our reserves estimates audited for their reasonableness by Netherland, Sewell & Associates, Inc., our independent petroleum engineers. Following the preparation of our reserves estimates, for the year ended December 31, 2008, we had our reserves estimates audited for their reasonableness by LaRoche Petroleum Consultants, Ltd., our independent petroleum engineers at that time. 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.

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Acreage Summary

The following table sets forth the approximate acreage in which we held a leasehold, mineral or other interest at September 30, 2011. At that date, only about 11% 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	1,696	1,422	50,357	27,484	52,053	28,906
Austin Chalk			24,454	14,849	24,454	14,849
Area Total(1)	1,696	1,422	50,357	27,484	52,053	28,906
NW Louisiana/E Texas:						
Haynesville	18,760	10,645	4,337	4,060	23,097	14,705
Cotton Valley(2)	21,039	17,901	5,502	5,335	26,541	23,236
Area Total(3)	23,080	19,696	6,048	5,781	29,128	25,477
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	6,481	10,714	7,519
Total	25,936	22,156	210,327	175,608	236,263	197,764

(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 number of gross and net undeveloped acres at September 30, 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 2011		Acres Expiring 2012		Acres Expiring 2013	
	Gross	Net	Gross	Net	Gross	Net
South Texas:						
Eagle Ford	1,341	279	15,815	4,353	14,345	9,092
Austin Chalk	597	120	6,051	1,122	3,848	2,644
Area Total(1)	1,341	279	15,815	4,353	14,345	9,092
NW Louisiana/E Texas						
Haynesville	173	125	815	487	118	118
Cotton Valley	186	138	921	493	118	118

Area Total(2)	186	138	921	493	118	118
SW Wyoming, NE Utah, SE Idaho			102,678	93,356	8,461	8,301
SE New Mexico, West Texas	7,362	2,723	1,725	92	8,454	2,715
Total	8,889	3,140	121,139	98,294	31,378	20,226

(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.

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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, 2010, 2009 and 2008 and the nine months ended September 30, 2011:

	Year Ended December 31,						Nine Months Ended September 30,	
	2010		2009		2008		2011	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Development Wells								
Productive	5	1.7	3	1.3	25	12.7	18	0.4
Dry								
Exploration Wells								
Productive	36	3.4	15	6.0	12	8.6	15	5.5
Dry			2	2.0	1	1.0		
Total Wells								
Productive	41	5.1	18	7.3	37	21.3	33	5.9
Dry			2	2.0	1	1.0		

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 company s 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 fluctuation 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. 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, 2008, we had two significant purchasers that each accounted for more than 10% of our total oil and natural gas revenues: Regency Gas Services LP (45%) and J-W Operating Company (24%). 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%). 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 are party to two natural gas transportation agreements at December 31, 2010 and September 30, 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

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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.

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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, as well as under Section 311 of the Natural Gas Policy Act. 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 Energy Policy Act of 2005. The Energy Policy Act, among other things, amended the Natural Gas Act 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 Natural Gas Act, the Natural Gas Policy Act of 1978, 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 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

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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 U.S. 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.

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.

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 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 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.

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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 saltwater 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 saltwater 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 OPA 90, 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. 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 imposes restrictions and strict controls regarding the discharge of produced waters and other wastes 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 state and federal waters and to conduct construction activities in 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 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, or SPCC, 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. Our operations may, and in all likelihood will, involve the use or handling of materials that may be classified as hazardous substances under CERCLA. 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. 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. 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 or cleanup 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.

On December 15, 2009, the EPA published its finding 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 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.

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In addition, at the federal level and in some states, there has been a push to place additional regulatory burdens upon hydraulic fracturing 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 September 1, 2011. State regulators have until 2013 to complete implementing rules. In addition, at least three 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.

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.

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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 form 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 30, 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.

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.

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MANAGEMENT

Officers

The following table sets forth the names, ages and positions of our executive officers at December 1, 2011:

Name	Age	Positions Held With Us
Joseph Wm. Foran	59	Chairman of the Board, Chief Executive Officer and President
David E. Lancaster	55	Executive Vice President, Chief Operating Officer and Chief Financial Officer
Matthew V. Hairford	50	Executive Vice President Operations
David F. Nicklin	62	Executive Director of Exploration
Wade Massad	44	Executive Vice President Capital Markets
Scott E. King	53	Co-Founder, Vice President Geophysics and New Ventures
Bradley M. Robinson	57	Vice President Reservoir Engineering

The following biographies describe the business experience of our executive officers. Each officer serves at the discretion of our board of directors. There are no family relationships among any of our officers.

Mr. Joseph Wm. Foran. Mr. Foran founded Matador Resources Company in July 2003 and has served as Chairman of the Board, Chief Executive Officer, President and Secretary since July 2003. He is also chairman of the board s Executive Committee. Mr. Foran began his career as an oil and natural gas independent in 1983 when he and his wife, Nancy, founded Foran Oil Company with $270,000 in contributed capital from 17 of his closest friends and neighbors. Foran Oil Company was later contributed into Matador Petroleum Corporation upon its formation by Mr. Foran in 1988, and Mr. Foran served as Chairman and Chief Executive Officer of that company from inception until the time of its sale to Tom Brown, Inc. in June 2003 for an enterprise value of $388 million in an all-cash transaction. Under Mr. Foran s guidance, Matador Petroleum realized a 21% average annual rate of return for its shareholders for 15 years. Mr. Foran is originally from Amarillo, Texas, where his family owned a pipeline construction business. From 1980 to 1983, he was Vice President and General Counsel of J. Cleo Thompson and James Cleo Thompson, Jr., Oil Producers. Prior to that time, he was a briefing attorney to Chief Justice Joe R. Greenhill of the Supreme Court of Texas. Mr. Foran graduated with a Bachelor of Science degree in Accounting from the University of Kentucky with highest honors and a law degree from the Southern Methodist University School of Law, where he was a Hatton W. Sumners scholar and the Leading Articles Editor of the Southwestern Law Review. He is currently active as a member of various industry and civic organizations, including his church and various youth activities. In 2002, Mr. Foran was honored as the Ernst & Young Entrepreneur of the Year for the Southwest Region. As the founder and Chairman of the Board, Chief Executive Officer and President of Matador Resources Company, Mr. Foran has provided leadership, experience and long relationships with a vast majority of the shareholders.

Mr. David E. Lancaster. Mr. Lancaster joined Matador Resources Company in December 2003 and serves as Executive Vice President, Chief Operating Officer and Chief Financial Officer. Mr. Lancaster has served in several capacities since joining Matador, including Vice President Business Development, Acquisitions and Finance from December 2003 to May 2005; Vice President and Chief Financial Officer from May 2005 to May 2007; and Executive Vice President and Chief Financial Officer from May 2007 to May 2009. He assumed his current role in May 2009. From August 2000 to December 2003, he was Marketing Manager for Schlumberger Limited s Data & Consulting Services which provides full-field reservoir characterization, production enhancement, multidisciplinary reservoir and production solutions and field development planning. In this position, he was responsible for global marketing strategies, business models, input to research and development, commercialization of new products and services and

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marketing communications. From 1999 to 2000, Mr. Lancaster was Business Manager, North and South America, for Schlumberger Holditch-Reservoir Technologies, the petroleum engineering consulting organization formed following Schlumberger s acquisitions of S. A. Holditch & Associates, Inc. and Intera Petroleum Services. In this role, he was responsible for the business operations of 12 consulting offices throughout North and South America. Mr. Lancaster worked with Schlumberger for six years following its acquisition of S. A. Holditch & Associates, Inc. in October 1997. He joined S. A. Holditch & Associates in 1980, and was one of the principals in that well-known petroleum engineering consulting firm. Between 1980 and 1997, Mr. Lancaster held positions ranging from Senior Petroleum Engineer to Senior Vice President Business Development. In this latter role, he was responsible for marketing and sales, as well as the company s commercial training business. During most of his tenure at S. A. Holditch & Associates, Inc., Mr. Lancaster was a consulting reservoir engineer with particular emphasis on characterizing and improving production from unconventional natural gas reservoirs. For more than seven years during this time, he was the Project Manager for the Gas Research Institute s Devonian Shales applied research projects investigating ways to improve reservoir characterization, completion practices and natural gas recovery in low permeability, natural gas shale reservoirs. He was also the lead reservoir engineer for the Secondary Gas Recovery project sponsored by the Gas Research Institute and the U.S. Department of Energy looking at ways to improve recovery from compartmentalized natural gas reservoirs in north and south Texas. Mr. Lancaster began his career as a reservoir engineer for Diamond Shamrock Corporation in 1979. Mr. Lancaster received Bachelor and Master of Science degrees in Petroleum Engineering from Texas A&M University in 1979 and 1988, respectively. He has authored or co-authored more than 50 technical papers and articles, as well as numerous other published reports and industry presentations. He is a member of the Society of Petroleum Engineers, and he served as a charter member and former Vice Chairman of the Texas A&M University Petroleum Engineering Advisory Board. Mr. Lancaster is a Licensed Professional Engineer in the State of Texas.

Mr. Matthew V. Hairford. Mr. Hairford joined Matador Resources Company in July 2004 as its Drilling Manager. He was named Vice President Drilling in May 2005; Vice President Operations in May 2006; and in May 2009 assumed the title of Executive Vice President Operations. He is in charge of our drilling and production operations. He was previously with Samson Resources, an exploration and production company, as Senior Drilling Engineer, having joined Samson in 1999. His responsibilities there included difficult Texas and Louisiana Gulf Coast projects, horizontal drilling projects and a start-up drilling program in Wyoming. The scope of this work ranged from multi-lateral James Lime wells in east Texas to deep wells in south Texas and south Louisiana. Mr. Hairford has drilled many geo-pressured wells in Texas and Louisiana, along with normally pressured wells in southwestern Wyoming and east Texas. Additional responsibilities included a horizontal well program in Roger Mills County, Oklahoma at 15,000 feet vertical depth. Mr. Hairford has experience in air drilling, underbalanced drilling, drilling under mud caps and high temperature and pressure environments. From 1998 until 1999, Mr. Hairford served as Senior Drilling Engineer with Sonat, Inc. in Tyler, Texas, a global company involved with natural gas transmission and marketing, oil and natural gas exploration and production and oil services. There his responsibilities included Pinnacle Reef wells in east Texas and deep horizontal drilling in the Austin Chalk field in central Louisiana. From 1984 to 1998, Mr. Hairford served in various drilling engineering capacities with Conoco, Inc., an integrated energy company. His operational areas included the Appalachian Basin, Illinois Basin, Permian Basin, Texas Panhandle and Val Verde Basin. Mr. Hairford was selected as a member of a three-person team to explore the use of unconventional technologies to identify a potential step change in the drilling sector. Multiple techniques were evaluated and tested, including declassified defense department technologies. Additional Conoco assignments included both field and office drilling positions in Midland and Oklahoma City. Earlier in his career with Conoco, Mr. Hairford was selected to participate in the Conoco Rig Drilling Supervisor Training Program in Houston. This program consisted of two years

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working a regular rotation as a drilling representative on rigs and as a drilling engineer in various domestic offices. Mr. Hairford began his career in 1984 with Conoco in a field production assignment in Hobbs, New Mexico. Mr. Hairford received his Bachelor of Science degree in Petroleum Engineering Technology from Oklahoma State University in 1984. He is an active member of the American Association of Drilling Engineers, the American Petroleum Institute and the Society of Petroleum Engineers. Mr. Hairford has also undertaken additional training through Stanford University s Executive Education programs including, most recently in the summer of 2011, the Stanford Graduate School of Business flagship six week Stanford Executive Program (SEP).

Mr. David F. Nicklin. Mr. Nicklin joined Matador Resources Company in February 2009 as Executive Director of Exploration, after working with us as a part-time consultant since November 2007. Prior to joining Matador, Mr. Nicklin provided executive level consulting services to a variety of clients from January 2000 onwards through his wholly owned corporation, David F. Nicklin International Consulting Inc. In 2006, Mr. Nicklin co-founded and currently leads a small, private oil and natural gas company, Salt Creek Petroleum LLC. Salt Creek Petroleum owns small, non-operated interests in a variety of onshore oil and natural gas fields in the United States. Since 2009, Mr. Nicklin has consulted almost exclusively for us, with the primary exception of the minimal time he has devoted to Salt Creek Petroleum. Mr. Nicklin worked approximately 210 days for us in both 2009 and 2010 and is expected to work a similar number of days for us in 2011. We have determined that Mr. Nicklin s involvement with Salt Creek Petroleum does not detract from his performance for our company and does not result in any conflict of interest between Mr. Nicklin and our company due to the fact that Salt Creek Petroleum is not involved in plays and prospects that compete with our interests. In 2000, he founded and led for three years a private oil and natural gas exploration company, Serica Energy, which is now a public company with assets in Indonesia, the United Kingdom, Spain, Ireland and Morocco. Between 1981 and 2000, Mr. Nicklin was an employee of ARCO, an integrated energy company, where he participated in and led several international exploration teams, particularly in the Middle East, southeast Asia and Australasia. In 1991, he became the Chief Geologist for ARCO, a position he held until his retirement in 2000. In this position, Mr. Nicklin was responsible for the quality of the geological effort at ARCO, in particular, ensuring the application of state-of-the-art geological technology, the company s risk management process, the selection of new ventures and the high-grading of a large geoscience staff. Throughout his career at ARCO, Mr. Nicklin was closely involved with the successful exploration for and development of a number of large oil and natural gas discoveries. Prior to joining ARCO, Mr. Nicklin was a senior development and operations geologist in a variety of positions in the United Kingdom, Angola, Norway and the Middle East. He was a specialist in well-site operations and provided training in operations to entry-level personnel. Mr. Nicklin was born in the United Kingdom and received a Bachelor of Science degree in Geology from the University of Wales in 1971. He is an active member of the American Association of Petroleum Geologists and various other professional groups.

Mr. Wade Massad. Mr. Massad joined Matador Resources Company in December 2011 as Executive Vice President, Capital Markets, after working as an advisor to the Matador Board of Directors since September 2010. Mr. Massad is the Co-Founder and Co-Managing Member of Cleveland Capital Management L.L.C., a registered investment advisor and General Partner of Cleveland Capital L.P., a private investment fund focused on micro-cap public and private equity securities, since October 1996. Previously, Mr. Massad was an investment banker with Keybanc Capital Markets and RBC Capital Markets where he was the head of U.S equity institutional sales from 1997 to 1998 and the head of U.S Capital Markets business from 1999 to 2003. He also served on the firm s executive committee at RBC. Mr. Massad has served on multiple public and private company boards and currently is a board member of 4Kids Entertainment. Mr. Massad received a Bachelor of Arts in business management from Baldwin-Wallace College in 1989 and currently serves on its Board of Trustees.

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Mr. Scott E. King. Mr. King co-founded Matador Resources Company with Mr. Foran and serves as our Vice President Geophysics and New Ventures. From July 2003 to February 2009, Mr. King held the position of Vice President Exploration, and in February 2009, he assumed his current position. He was previously with Matador Petroleum Corporation, joining that company in December 1996 as Chief Geophysicist. Immediately prior to Matador Petroleum s sale, Mr. King served as its Portfolio Manager and was responsible for recommending which drilling opportunities Matador Petroleum should pursue. Prior to joining Matador Petroleum, Mr. King worked for Enserch Corporation, a diversified energy company with interests in petroleum exploration and production, oilfield services, engineering design and construction, and natural gas transmission and distribution, as Team Leader for the Oklahoma Asset Group. Mr. King began his career in 1983 with Sohio Petroleum, an integrated energy company. The Sohio assets were sold and resold to a number of companies, including BP p.l.c., Tex-Con Oil Co., Pacific Gas and Electric Company, Dalen Resources Oil & Gas Co., and finally Enserch Corporation. During this time, Mr. King worked for and was retained by each of these companies and had success in generating and managing drilling opportunities in the continental United States. Mr. King received a Bachelor of Science degree in Geology with a Minor in Mathematics from Alfred University, Alfred, New York in 1981 and a Master of Science degree in Geophysics from Wright State University, Dayton, Ohio in 1983. Mr. King is active in various professional and civic groups including the American Association of Petroleum Geologists and the Society of Exploration Geophysicists.

Mr. Bradley M. Robinson. Mr. Robinson joined Matador Resources Company in August 2003 as one of its founders and has served as our Vice President Reservoir Engineering since that time. Prior to joining Matador, from 1997 to August 2003, Mr. Robinson held the position of Advisor with Schlumberger Limited s Data & Consulting Services business unit which provides full-field reservoir characterization, production enhancement, multidisciplinary reservoir and production solutions and field development planning where he was responsible for the development and application of new technologies for well completions and stimulation, provided technical expertise for reservoir management and field development projects, taught basic and advanced industry courses in well completions and stimulation and provided internal training in production engineering and stimulation methods. Mr. Robinson worked with Schlumberger for six years following its acquisition of S. A. Holditch & Associates, Inc. in 1997. Mr. Robinson joined Holditch in 1979, and was one of the principals in that well-known petroleum engineering consulting firm. From 1979 to 1982, Mr. Robinson served as Senior Petroleum Engineer and was involved in all aspects of reservoir and production engineering for both conventional and low permeability oil and natural gas fields. From 1982 to 1997, he was Holditch s Vice President Production Engineering, where he was responsible for coordination and management of production and completion engineering projects, including development drilling and openhole data acquisition programs, design and supervision of initial well completions and workovers, transient well test design and analysis and hydraulic fracture stimulation design and supervision. His duties also included reserves evaluation and economic analysis of new and existing wells, and his areas of specialization included low permeability natural gas sands, coalbed methane reservoirs, and horizontal wells. For approximately 10 years during this time, he served as assistant project manager for the Gas Research Institute s Tight Gas Sands and Horizontal Gas Wells applied research projects investigating ways to improve reservoir characterization, completion practices and natural gas recovery in low permeability natural gas reservoirs and horizontal natural gas wells. During his career, he has worked all over the world including the United States, Canada, Venezuela, Colombia, Mexico, Egypt, the North Sea, Russia and Indonesia, among others. Mr. Robinson began his career in 1977 with Marathon Oil Company, serving as an Associate Production Engineer and later as a Reservoir Engineer in Midland. Mr. Robinson received Bachelor and Master of Science degrees in Petroleum Engineering from Texas A&M University in 1977 and 1986, respectively. He has authored or co-authored 18 technical articles appearing in industry and/or technical publications and has made numerous engineering technical presentations. Mr. Robinson is a member of the Society of Petroleum Engineers and is a Licensed Professional Engineer in the State of Texas.

Board of Directors

Our board of directors consists of eight directors. The following biographies describe the business experience of our directors, other than Mr. Foran. There are no family relationships among any of our officers and directors.

Mr. Charles L. Gummer. Mr. Gummer, age 65, joined our board of directors in September 2011. He has over 40 years of banking experience with Comerica Bank. From July 31, 2010 through October 31, 2011, he was Chairman of Comerica Bank Texas Market. From 1989 until July 31, 2010, he was President and Chief Executive Officer of Comerica Bank Texas. He earned his Bachelor of Science degree from The Ohio State University and his Master of Business Administration from Wayne State University. He also graduated from the University of Michigan s Graduate School of Banking and Financial Services. In addition to his professional career with Comerica Bank, he has also been very involved in the Dallas community, including as a current member of the Dallas Summer Musicals executive committee, the board of Downtown Dallas, Inc., the executive board of the Southern Methodist University Cox School of Business, the board of the Better Business Bureau of Dallas, the advisory board of the Vogel Alcove Arts Performance Committee, the advisory committee of the Greater Dallas Chamber of Commerce Economic Development, the advisory committee of Bishop Lynch High School and the board of The Catholic Foundation. Mr. Gummer s experience as a former Chairman, President and Chief Executive Officer and a senior executive of a publicly-traded bank, combined with his banking and mergers and acquisitions experience, plus his civic involvements provide our board of directors with extensive executive leadership, strategic planning, finance and general business expertise.

Dr. Stephen A. Holditch. Dr. Holditch, age 65, was a shareholder in and advisor to Matador Petroleum Corporation and is an original shareholder in Matador Resources Company. He was first elected to our board of directors in January 2004 and currently serves as chairman of the board s Engineering Committee. He is Professor and Head of the Harold Vance Department of Petroleum Engineering at Texas A&M University, having assumed this position in January 2004. Prior to that, he was with Schlumberger Limited, a leading oilfield services provider, as a Fellow, one of only a handful of technical experts so recognized with this title in that company. In this position, Dr. Holditch advised top management within Schlumberger Limited on production and reservoir engineering matters. Dr. Holditch joined Schlumberger in 1997, following Schlumberger Limited s acquisition of S. A. Holditch & Associates, Inc., the consulting company he founded and grew over 20 years into a preeminent engineering firm worldwide in the analysis of low permeability natural gas reservoirs and the design of hydraulic fracture treatments. During the latter half of the 1980 s and into the 1990 s, Dr. Holditch expanded the services offered by S. A. Holditch & Associates, building the company from three employees in 1977 to more than 80 employees in 1998. At the time of its sale to Schlumberger in 1997, S. A. Holditch & Associates had become a full-service petroleum engineering consulting company. From 1974 to 1976, Dr. Holditch worked as an independent consulting engineer on reservoir studies, well completions and fracture treatment design for numerous clients in east and south Texas. During that period, he also attended Texas A&M University to earn a PhD degree in Petroleum Engineering and conducted research in reservoir flow behavior in fractured, low permeability natural gas reservoirs. From 1970 to 1974, he was a Production Engineer with Shell Oil Company, an integrated energy company, where his responsibilities included production engineering for numerous oil and natural gas fields, well completions and massive hydraulic fracture treatment designs in several deep, geopressured

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fields in south Texas. From 1968 to 1969, he worked for Pan American Petroleum Corporation as a field engineer on various projects in east Texas. Dr. Holditch received Bachelor and Master of Science degrees in Petroleum Engineering from Texas A&M University in 1969 and 1970, respectively, and a PhD degree in Petroleum Engineering from Texas A&M University in 1976. Dr. Holditch was President of the Society of Petroleum Engineers, International (SPE) in 2002 and served on the Society s board of directors from 1998 to 2003. In addition, he served as a Trustee for the American Institute of Mining, Metallurgical, and Petroleum Engineers from 1997 to 1998. He is also on the board of directors of Triangle Petroleum Corporation, an oil and natural gas exploration corporation. He has received numerous awards in recognition of his technical achievements and leadership. In 1995, Dr. Holditch was elected to the National Academy of Engineering, the highest professional honor awarded to an engineer. In 1997, he was elected to the Russian Academy of Natural Sciences, and in 1998, Dr. Holditch was elected to the Petroleum Engineering Academy of Distinguished Graduates at Texas A&M University and was recently named distinguished alumnus of engineering. Dr. Holditch received the SPE Distinguished Service Award for Petroleum Engineering Faculty in 1981 and held the Shell Distinguished Chair in Petroleum Engineering at Texas A&M University from 1983 to 1987. He was awarded the R. L. Adams Professorship in 1995. He teaches graduate level courses in formation evaluation, well stimulation and production engineering, and has actively performed and supervised research at Texas A&M University since 1974 in a wide range of engineering areas. Dr. Holditch is a member of numerous professional societies and serves as a board member and/or trustee for several business affiliations. He has been an SPE Distinguished Lecturer and has co-authored or edited three books and more than 100 technical papers; he has made more than 80 invited technical presentations to petroleum industry audiences. His position as Professor and Head of the Harold Vance Department of Petroleum Engineering at Texas A&M University, his prior positions with Schlumberger and S. A. Holditch & Associates, Inc. and his service on the board of directors of Triangle Petroleum Corporation provide our board of directors with additional perspective on our completion and stimulation operations and other business and engineering matters.

Mr. David M. Laney. Mr. Laney, age 62, is an original shareholder in Matador Resources Company and was an original shareholder in Matador Petroleum Corporation. He was one of the original directors on our board of directors in July 2003 and currently serves as lead independent director and chairman of the board s Nominating, Compensation and Planning Committee. He is an attorney who since March 2007 has practiced law as a solo practitioner. Between 2003 and 2007, he was a partner with the law firm of Jackson Walker LLP in Dallas where he practiced in the area of corporate and financial law. Prior to joining Jackson Walker, Mr. Laney practiced at the law firm of Jenkens & Gilchrist, a Professional Corporation, from 1977 to 2003 and was managing partner of the Jenkens & Gilchrist law firm from 1990 to 2002. During his tenure as Managing Partner, Jenkens & Gilchrist was recognized as one of the fastest growing firms in the country and was named by industry press as among the top 50 firms in the country (from the standpoint of size and financial performance). From a regional law firm of roughly 160 lawyers in two Texas cities in 1990, the firm expanded under Mr. Laney s leadership to over 625 attorneys in nine cities by the end of his tenure in 2002. Mr. Laney has also served in several capacities as an appointee of Texas Governors William Clements and George W. Bush on various state boards continuously from 1989 through 2001. He was Governor Clements appointee to the Texas Finance Commission, responsible for regulatory oversight of the state banking and thrift industries as the Texas banking system emerged from the recession and collapse of the 1980 s. He then served as Governor Bush s Texas Commissioner of Transportation (Chairman of the Texas Department of Transportation) during the period 1995 to 2000. Mr. Laney completed his term with the Texas Department of Transportation (TxDOT) in 2001. As Commissioner of Transportation, his responsibilities were largely those of the chief executive of TxDOT, a 14,000 employee state agency with a $5 billion annual budget. In that position, he initiated and oversaw the planning and successful execution of an extensive number of organizational and operational innovations throughout the organization, and developed and managed TxDOT s

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legislative agenda during three regular sessions of the Texas Legislature. In 2002, Mr. Laney was nominated by President George W. Bush to the board of directors of Amtrak and confirmed by the U. S. Senate for a five-year term. In November 2007, he completed his term as Chairman of Amtrak s board of directors. From 1998 to 2003, Mr. Laney served as a member of the Stanford University Board of Trustees, and for two years as Chairman of its Audit Committee. Mr. Laney has also served in various capacities in connection with numerous civic and educational organizations and projects in the Dallas area. Mr. Laney s legal experience and leadership positions in governmental departments provide our board of directors with additional perspective on our corporate governance, legal and governmental relations matters and general business matters.

Mr. Gregory E. Mitchell. Mr. Mitchell, age 60, joined our board of directors in June 2011. With 45 years of grocery and petroleum retailing experience, he is currently President and CEO of Toot n Totum Food Stores, LLC, his family company, which is located in Amarillo, Texas. The company, founded in 1950, consists of 62 convenience store/fueling locations, as well as car wash and car care centers, with an employee base of over 700 team members. His experience within the petroleum industry includes extensive negotiations with various major refiners in the United States. A 1973 graduate of the University of Oklahoma, with a Bachelor of Business Administration degree, Mr. Mitchell was appointed by former Governor William Clements to the Texas Higher Education Coordinating Board, where he served for six years. Additionally, he has served as Chairman of the Amarillo Chamber of Commerce, Chairman of the United Way of Amarillo and Canyon, Chairman of the Don and Sybil Harrington Foundation and President of the Amarillo Area Foundation. Currently, Mr. Mitchell is a director of the Holding Committee for Amarillo National Bank, a director of Cal Farley s Boys Ranch and a director of Wigel s Convenience Stores in Knoxville, Tennessee. Mr. Mitchell s experience as President and CEO of his large family business and as a director of several companies provides our board of directors with extensive business, strategic and executive leadership experience.

Dr. Steven W. Ohnimus. Dr. Ohnimus, age 65, was first elected to our board of directors in January 2004 and currently serves as chairman of the board s Operations Committee. He spent his entire professional career from 1971 to 2000 with Unocal Corporation, an integrated energy company. From 1995 to 2000, he was General Manager Partner Operated Ventures, where he represented Unocal s non-operated international interests at board meetings, management committees and other high level meetings involving projects in the $200 million range in countries such as Azerbaijan, Bangladesh, China, Congo, Myanmar and Yemen. From 1994 to 1995, Dr. Ohnimus was General Manager of Asset Analysis, where he managed and directed planning, business plan budgeting and scenario plans for the domestic and international business unit with an asset portfolio totaling $5.5 billion. From 1990 to 1994, Dr. Ohnimus was Vice President and General Manager, Unocal Indonesia, located in Balikpapan, operating five offshore fields and one onshore liquid extraction plant and employing 1200 nationals and 50 expatriates. From 1989 to 1990, he served as Regional Operations Manager in Anchorage, Alaska, and from 1988 to 1989, he was District Operations Manager in Houma, Louisiana. From 1981 to 1988, Dr. Ohnimus was in various management assignments in Houston and Houma, Louisiana, and from 1971 to 1981 he handled various technical assignments in reservoir, production and drilling in the Gulf Coast area (Houston, Van, Lafayette and Houma). From 1975 to 1979, Dr. Ohnimus was Assistant Professor of Petroleum Engineering at the University of Southwest Louisiana (now University of Southern Louisiana) where he taught a total of eleven undergraduate and graduate night classes. In 1980, he taught drilling seminars at the University of Texas Petroleum Extension Service of the International Association of Drilling Contractors (IADC). Dr. Ohnimus has authored several published papers concerning reservoir recompletion and increased recovery. Dr. Ohnimus received his Bachelor of Science degree in Chemical Engineering from the University of Missouri at Rolla in 1968, a Master of Science degree in Petroleum Engineering from the University of Missouri at Rolla in 1969 and a PhD degree in Petroleum Engineering from the University of

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Missouri at Rolla in 1971. Dr. Ohnimus served as a director of the American Petroleum Institute in 1978 and 1979, served as Session Chairman for the Society of Petroleum Engineers Annual Convention in 1982, was the Evangeline Section Chairman of the Society of Petroleum Engineers in 1978 and 1979 and served as President of the Unocal Credit Union from 1986 to 1988. In 2007, he was elected President of the Unocal Gulf Coast Alumni Club, which reports through the Chevron Retirees Association. He still holds that position. In June 2008, Dr. Ohnimus was elected as the vice chairman of the advisory board of Western Standard Energy Corp. (OTCBB:WSEG), an oil and natural gas exploration company. Due to his long oil and natural gas industry career and significant operational and international experience, Dr. Ohnimus provides valuable insight to our board of directors on our drilling and completion operations and management, as well as providing a global technology and operations perspective.

Mr. Michael C. Ryan. Mr. Ryan, age 51, joined our board of directors in February 2009 and currently serves as chairman of the board s Audit Committee. Prior to joining the board, he served as a Board Advisor to the Financial Committee and frequently participated in board planning and strategy sessions. Since October 2004, Mr. Ryan has been a Partner and member of the Investment Committee at Berens Capital Management LLC, an investment firm based in New York. From February 1998 to June 2004, he worked with Goldman, Sachs & Co., a global investment banking and securities services firm, leading its West Coast international institutional equities business. In this role, he developed and built a team of professionals to advise large institutional clients on their global investment decisions. From 1995 to 1998, Mr. Ryan lived in Oslo, Norway, where he was a Partner at Pareto Securities, a Scandinavian-based securities firm where he led and built the institutional equities business into the United States and United Kingdom. From 1991 to 1994, Mr. Ryan represented multiple eastern European governments in the preparation, negotiation and sale of many of their largest state-owned companies. He began his career with Honeywell, Inc. which invents and manufactures technologies, including in the safety, security and energy areas, in 1983, working in the Systems and Research Center, which focused on advanced weapons development programs. Mr. Ryan received a Master of Business Administration degree from The Wharton School at the University of Pennsylvania and a Bachelor of Science degree from the University of Minnesota. Mr. Ryan s background and experience in the domestic and international financial world provide our board of directors with additional perspective on accounting and auditing functions, economic trends and our capital sourcing and financing opportunities.

Mrs. Margaret B. Shannon. Mrs. Shannon, age 62, joined our board of directors in June 2011 and currently serves as chairperson of the board s Corporate Governance Committee. She served as Vice President and General Counsel of BJ Services Company, an international oilfield services company, from 1994 to 2010, when Baker Hughes Incorporated acquired BJ Services. Prior to 1994, she was a partner with the law firm of Andrews Kurth LLP. Mrs. Shannon is active in community activities serving as the Chair of the Membership Committee of the board of directors of the Harris County Health Alliance, Chair of the Audit Committee of the board of directors of the South Texas College of Law, chair of the Endowment Board of Palmer Memorial Episcopal Church and a member of the board of directors of the Harris County Health and Human Services Foundation. She previously served as the Chair of the Executive Women s Partnership sponsored by the Greater Houston Partnership and was a participant in the American Leadership Forum. Mrs. Shannon received her J.D. cum laude from Southern Methodist University Dedman School of Law in 1976 and her Bachelor of Arts degree from Baylor University in 1971. Mrs. Shannon s experience as an attorney, as a partner with Andrews Kurth LLP, as general counsel for a public company for more than 15 years and as a director for numerous other organizations provides our board of directors with important insights into public company obligations, corporate governance and board functions.

Although our bylaws include a mandatory retirement age of 70 for directors, our board of directors is permitted to waive such restriction on an annual basis up to age 75 upon the determination by the board that such waiver is in the best interest of the company.

In addition, our board is divided into three classes of directors, designated Class I, Class II and Class III, with the term of office of each director ending on the date of the third annual meeting following the annual meeting at which such director was elected. The numbers of directors in each class will be as nearly equal as possible at all times. The current Class I directors are Mrs. Shannon and Messrs. Gummer and Ryan, who will hold office until the 2012 annual meeting of shareholders and until the election and qualification of their respective successors or until their earlier death, retirement, resignation or removal. The current Class II directors are Mr. Mitchell and Dr. Ohnimus, who will hold office until the 2013 annual meeting of shareholders and until the election and qualification of their respective successors or until their earlier death, retirement, resignation or removal. The current Class III directors are Messrs. Foran and Laney and Dr. Holditch, who will hold office until the 2014 annual meeting of shareholders and until the election and qualification of their respective successors or until their earlier death, retirement, resignation or removal.

Special Board Advisors

In addition to our board of directors, we have three individuals who have significant oil and gas experience or legal, accounting and other business experience who advise our board of directors on various matters. Other than indemnification agreements in form similar to those entered into with our directors and officers, we have not entered into written agreements with these individuals with respect to their service as special advisors to our board of directors. Their business histories are described below:

Mr. Marlan W. Downey. Mr. Downey worked for Shell Oil Company, an integrated energy company, from 1957 to 1987. In 1977, he moved to Shell Oil s International Exploration & Production business and became Vice President of Shell, and then President of Shell Oil s newly-formed international subsidiary, Pecten International. Mr. Downey joined ARCO International in 1990 as Senior Vice President of Exploration, becoming President of ARCO International and then Senior Vice President and Executive Exploration Advisor to ARCO International. Mr. Downey retired from ARCO in 1996. He is a fellow of the American Association for the Advancement of Science. Mr. Downey is a past President of the American Association of Petroleum Geologists (AAPG) and is Chief Scientist Sarkeys Energy Center at Oklahoma University. Mr. Downey is the 2009 recipient of the AAPG s Sidney Powers Medal, which is the highest honor awarded by the AAPG. He is also active in several international scientific organizations and serves on boards of the Institute for the Study of Earth and Man, and the Reves Institute for International Studies at William and Mary. Mr. Downey received a Bachelor of Arts degree in Chemistry in 1952 at Peru State College in Nebraska. He served in the Army in Korea and the Philippines, then entered graduate school at the University of Nebraska, and received a Bachelor of Science degree in 1956 and a Master of Science degree in Geology in 1957. Mr. Downey previously served on Matador Petroleum Corporation s board of directors with Mr. Foran. He has served as a special advisor since our inception in July 2003 and currently serves as chairman of the board s Prospect Committee.

Mr. Edward J. Scott, Jr. Mr. Scott is a successful Amarillo, Texas lawyer, civic leader and businessman, managing a varied portfolio of real estate and development-related concerns. Currently, he is the primary developer for two residential developments in Amarillo: Pheasant Run and The Greenways. He serves as primary owner of Document Shredding & Storage which services the entire Panhandle area, Sparky s Storage Solutions in Amarillo, Texas and is part owner in several car washes in the Lubbock, Abilene and Dallas/Fort Worth areas. From 1968 to 1996, Mr. Scott was an attorney with the Amarillo law firm of Gibson, Ochsner & Adkins. From 1965 to 1968, he served as an accountant with Price

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Waterhouse & Co. Mr. Scott received his Bachelor of Business Administration degree in Accounting from West Texas State University in 1962 and an LLB from The University of Texas School of Law in 1965. Mr. Scott has previously served as a director and chairman of the Amarillo Economic Development Corporation and is currently serving as a board member of the Salvation Army, Amarillo Area Foundation, as well as the Amarillo Club. He is a past President of the Rotary Club of Amarillo, the Amarillo Businessmen s Club, the Amarillo Club, Big Brothers and Big Sisters and the Amarillo Business Foundation. He is a former chairman of the Amarillo Board of City Development and a former member of the Board of Regents for West Texas State University. Mr. Scott has previously served as an officer and/or board member to many other local civic and/or charitable organizations. He is a member of the Texas Bar Association, the Amarillo Bar Association, the Texas Society of Certified Public Accountants and the Panhandle Chapter of the Texas Society of Certified Public Accountants. Mr. Scott is an original shareholder in both Matador Resources Company and the former Matador Petroleum Corporation. He was an original director on the Matador Resources Company board of directors and served as chairman of the Audit Committee for eight years until his retirement from the board in June 2011.

Mr. W.J. Jack Sleeper, Jr. Mr. Sleeper has over 55 years of experience evaluating oil and gas properties. Mr. Sleeper joined DeGolyer and MacNaughton, a petroleum consulting firm, as a Petroleum Engineer in 1965. He performed numerous field studies in North and South America, the North Sea and the Middle East. Mr. Sleeper retired as President and Chief Operating Officer of DeGolyer and MacNaughton on January 1, 1995. He served on DeGolyer and MacNaughton s board of directors from 1978 until his retirement. Upon his graduation from the University of Oklahoma with a Bachelor of Science degree in Petroleum Engineering (with Distinction) in 1955, he was employed by Shell Oil Company, an integrated energy company, as an Exploitation Engineer. During his 10 years with Shell he spent three years performing research at Shell Development Company in the fields of Reservoir Engineering, Geology and Petrophysics. He held the titles of Project Engineer, Senior Exploitation Engineer and Senior Production Geologist during his tenure with Shell. Mr. Sleeper has served on the Mewborne Petroleum and Geological Board of Advisors at the University of Oklahoma since 1995. He is a Licensed Professional Engineer (retired) in the states of Oklahoma and Texas. Mr. Sleeper previously served on Matador Petroleum Corporation s board of directors with Mr. Foran. He has served as a special advisor since our inception in July 2003.

Committees of the Board of Directors

We have an Audit Committee, Nominating, Compensation and Planning Committee, Corporate Governance Committee, Executive Committee, Operations Committee, Engineering Committee, Financial Committee and Prospect Committee and may have such other committees as the board of directors shall determine from time to time. The charters of each of the Audit Committee, Nominating, Compensation and Planning Committee and Corporate Governance Committee will be available on our website at www.matadorresources.com concurrently with, or prior to, the completion of this offering. Each of the standing committees of the board of directors have the composition and responsibilities described below.

Audit Committee

The Audit Committee assists the board of directors in monitoring:

- the integrity of our financial statements and disclosures;
- our compliance with legal and regulatory requirements;
- the qualifications and independence of our independent auditor;
- the performance of our internal audit function and our independent auditor; and

- our internal control systems.

In addition, the Audit Committee is charged with the compliance of our Code of Ethics and Business Conduct for Officers, Directors and Employees.

Our Audit Committee currently consists of Messrs. Gummer, Laney, Mitchell and Ryan and Dr. Ohnimus, each of whom is independent under the rules of the NYSE and the SEC. Mr. Ryan is the chairman of the Audit Committee. SEC rules require a public company to disclose whether or not its audit committee has an audit committee financial expert as a member. An audit committee financial expert is defined as a person who, based on his or her experience, possesses the attributes outlined in such rules. Our board of directors has determined that Messrs. Gummer and Ryan are each audit committee financial experts.

Nominating, Compensation and Planning Committee

The Nominating, Compensation and Planning Committee has the following responsibilities:

- identify and recommend to the board of directors individuals qualified to be nominated for election to the board of directors;
- recommend to the board of directors the members and chairman of each committee of the board of directors;
- assist the board of directors and the independent members of the board of directors in the discharge of their fiduciary responsibilities relating to the fair and competitive compensation of our executive officers;
- provide overall guidance with respect to the establishment, maintenance and administration of our compensation programs, including stock and benefit plans;
- oversee and advise the board of directors and the independent members of the board of directors on the adoption of policies that govern our compensation programs; and
- recommend to the board of directors the strategy, tactical and performance goals of the company, including those performance and tactical goals that relate to performance based compensation, including but not limited to goals for production, reserves, cash flows and shareholder value.

Our Nominating, Compensation and Planning Committee currently consists of Mrs. Shannon and Messrs. Gummer, Laney, Mitchell and Ryan and Drs. Holditch and Ohnimus, each of whom is independent under the rules of the NYSE, a non-employee director pursuant to Section 16(b) of the Securities Exchange Act of 1934, as amended, or the Exchange Act, and an outside director pursuant to Section 162(m) of the Internal Revenue Code of 1986, as amended. Mr. Laney is the chairman of the Nominating, Compensation and Planning Committee.

The board of directors has also established a Director Nominating Advisory Committee that is charged with receiving and considering possible nominees for election by shareholders to the board of directors. Pursuant to the Director Nominating Advisory Committee charter, this committee will be comprised of 8 to 12 persons selected by the Nominating, Compensation and Planning Committee, and will consist of at least:

- two members of the Nominating, Compensation and Planning Committee;
- two former members of or special advisors to the board of directors;

two shareholders who beneficially own common stock having a market value of at least $1.0 million (such value to be based on the market value of the common stock immediately prior to designation of such shareholders to the Director Nominating Advisory Committee); and

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two shareholders who have beneficially owned common stock continuously for at least the five years prior to such shareholders designation to the Director Nominating Advisory Committee.

The Director Nominating Advisory Committee will make recommendations on its conclusions to the Nominating, Compensation and Planning Committee for its consideration and review.

Corporate Governance Committee

The Corporate Governance Committee is responsible for periodically reviewing and assessing our corporate governance guidelines and making recommendations for changes thereto to the board of directors, reviewing any other matters related to our corporate governance, unless the authority to conduct such review has been retained by the board of directors or delegated to another committee and overseeing the evaluation of the board of directors and management.

Our Corporate Governance Committee currently consists of Mrs. Shannon and Messrs. Gummer, Laney and Mitchell, each of whom is independent under the rules of the NYSE. Mrs. Shannon is chairperson of the Corporate Governance Committee.

Executive Committee

The Executive Committee has authority to discharge all the responsibilities of the board of directors in the management of the business and affairs of the company, except where action of the full board of directors is required by statute or by our certificate of formation.

Our Executive Committee consists of Messrs. Foran and Laney and Dr. Ohnimus, and Mr. Foran is chairman of the Executive Committee.

Operations Committee

We have, and anticipate continuing to have upon completion of this offering, an Operations Committee. The Operations Committee provides oversight over the development of our prospects, our drilling and completion operations and our production operations and associated costs. The current members of the Operations Committee are Messrs. Foran and Sleeper (ex-officio) and Drs. Holditch and Ohnimus, and Dr. Ohnimus is chairman of the Operations Committee.

Engineering Committee

We have, and anticipate continuing to have upon completion of this offering, an Engineering Committee. The Engineering Committee provides oversight over the amount and classifications of our reserves and the design of our completion techniques and hydraulic fracturing operations and various other reservoir engineering matters. The current members of the Engineering Committee are Messrs. Foran, Downey (ex-officio) and Sleeper (ex-officio) and Drs. Holditch and Ohnimus, and Dr. Holditch is chairman of the Engineering Committee.

Financial Committee

We have, and anticipate continuing to have upon completion of this offering, a Financial Committee. The Financial Committee provides oversight over our financial position, liquidity and capital needs and the various methods for financing our business. The current members of the Financial Committee are Messrs. Foran, Gummer, Laney, Mitchell and Ryan, and Mr. Foran is chairman of the Financial Committee.

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Prospect Committee

We have, and anticipate continuing to have upon completion of this offering, a Prospect Committee. The Prospect Committee provides oversight over the technical analysis, evaluation and selection of our oil and natural gas prospects. The current members of the Prospect Committee are Messrs. Foran, Downey and Sleeper (ex-officio) and Drs. Holditch and Ohnimus, and Mr. Downey is chairman of the Prospect Committee.

Nominating, Compensation and Planning Committee Interlocks and Insider Participation

No member of our Nominating, Compensation and Planning Committee is an employee of the Company. None of our executive officers serve on the board of directors or compensation committee of a company that has an executive officer that serves on our board of directors or Nominating, Compensation and Planning Committee. No member of our board of directors serves as an executive officer of a company in which one of our executive officers serves as a member of the board of directors or compensation committee of that company.

To the extent any members of our Nominating, Compensation and Planning Committee and affiliates of theirs have participated in transactions with us meeting the requirements of Item 404 of Regulation S-K, a description of those transactions is described in Certain Relationships and Related Party Transactions.

Code of Ethics and Business Conduct for Officers, Directors and Employees

Our board of directors has adopted a Code of Ethics and Business Conduct for Officers, Directors and Employees that complies with applicable U.S. federal securities laws and the corporate governance rules of the NYSE. Any waiver of this code may be made only by our officer responsible for monitoring compliance with such code (or Audit Committee in certain circumstances) and if required by applicable U.S. federal securities laws or the corporate governance rules of the NYSE will be promptly disclosed. A copy of the Code of Ethics and Business Conduct for Officers, Directors and Employees will be posted on our website concurrently with, or prior to, the completion of this offering.

Corporate Governance Guidelines

Our board of directors has adopted corporate governance guidelines in accordance with the corporate governance rules of the NYSE. A copy of the corporate governance guidelines will be posted on our website concurrently with, or prior to, the completion of this offering.

Director Independence

Our board of directors has reviewed the independence of our directors and considered whether any director has a material relationship with us that could compromise his or her ability to exercise independent judgment in carrying out his or her responsibilities. After this review, our board of directors determined that the following directors are independent directors as defined under the rules of the SEC and the NYSE: Mrs. Shannon, Messrs. Gummer, Laney, Mitchell and Ryan, and Drs. Holditch and Ohnimus.

Lead Independent Director

Our corporate governance guidelines provide that one of our independent directors should serve as a lead independent director at any time when the chief executive officer serves as the chairman of the board. The lead independent director presides over executive sessions of our independent directors, serves as a liaison between our chairman and the independent directors and performs such additional duties as our board of directors may otherwise determine and delegate. Because Mr. Foran serves as Chairman of the Board and Chief Executive Officer, our independent directors have appointed Mr. Laney to serve as lead independent director.

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COMPENSATION OF NAMED EXECUTIVE OFFICERS

Compensation Discussion and Analysis

In this compensation discussion and analysis, we discuss our compensation objectives, our decisions and the rationale behind those decisions relating to compensation for 2010 for our principal executive officer, our principal financial officer and our other three most highly compensated executive officers. Furthermore, this compensation discussion and analysis discusses our decisions to date regarding compensation for 2011 and 2012 in anticipation of closing this offering and the rationale behind those decisions. This compensation discussion and analysis provides a general description of our compensation program and specific information about its various components.

Named Executive Officers

Throughout this discussion, the following individuals are referred to as the Named Executive Officers and are included in the Summary Compensation Table:

- Joseph Wm. Foran, Chairman of the Board, Chief Executive Officer and President;
- 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 of Exploration; and
- Bradley M. Robinson, Vice President Reservoir Engineering.

Objectives of Our Compensation Program

Our future success and the ability to create long-term value for our shareholders depends on our ability to attract, retain and motivate highly qualified individuals in the oil and natural gas industry. Additionally, we believe that our success also depends on the continued contributions of our Named Executive Officers. Our executive compensation program is designed to provide a comprehensive compensation program to meet the following objectives:

- to be fair to both the executive and the company;
- to attract and retain talented and experienced executives with the skills necessary for us to execute our business plan;
- to provide opportunities to achieve a total compensation level that is competitive with comparable positions at companies with which we compete for executives;
- to align the interests of our executive officers with the interests of our shareholders and with the performance of our company for long-term value creation;

to provide financial incentives to our executives to achieve our key corporate and individual objectives;

to provide an appropriate mix of fixed and variable pay components to establish a pay-for-performance oriented compensation program;

to foster a shared commitment among executives by coordinating their corporate and individual goals;

to provide compensation that takes into consideration the education, professional experience and knowledge that is specific to each job and the unique qualities the executive provides; and

to recognize an executive s commitment and dedication in his job performance and in support of our culture.

What Our Compensation Program Is Designed to Reward

Our compensation program is designed to reward, in both the short-term and the long-term, performance that contributes to the implementation of our business strategies, maintenance of our culture and values and the achievement of our objectives. In addition, we reward qualities that we believe help achieve our business strategies such as teamwork; individual performance in light of general economic and industry-specific conditions; relationships with shareholders and vendors; the ability to manage and enhance production from our existing assets; the ability to explore new opportunities to increase oil and natural gas production; the ability to identify and acquire additional acreage; the ability to increase year-over-year proved reserves; the ability to control unit production costs; level of job responsibility; industry experience; and general professional growth.

2010

Elements of Our 2010 Compensation Program and Why We Paid Each Element

For 2010, our management compensation program was comprised of the following four elements:

Base Salary. We paid base salary to reward an executive for his assigned responsibilities, experience, leadership and expected future contribution.

Discretionary Cash Bonus. We included a discretionary cash bonus as part of our management compensation program because we believed this element of compensation (i) helped focus and motivate management to achieve key corporate and individual objectives by rewarding the achievement of these objectives; (ii) helped retain management; (iii) rewarded our successes over the prior year; and (iv) was necessary to be competitive from a total remuneration standpoint.

Long-Term Equity Incentive Compensation. We used stock options as the primary vehicle for (i) linking our long-term performance and increases in shareholder value to the total compensation for our executive officers and (ii) providing competitive compensation to attract and retain our executive officers.

Benefits. We offered a variety of health and welfare programs to all eligible employees, including the executive officers other than Mr. Nicklin. The health and welfare programs were intended to protect employees against catastrophic loss and encourage a healthy lifestyle.

How We Determined Each Element of 2010 Compensation

In 2010, we had a Planning and Compensation Committee which, together with the board of directors, oversaw our compensation program in conjunction with the recommendations made by Mr. Foran and Mr. Laney, the chairman of the Planning and Compensation Committee. The 2010 base salaries and the 2009 bonuses were set in December 2009. In December 2009, Mr. Foran evaluated the other Named Executive Officers, and, based on his general knowledge of compensation ranges in the oil and natural gas industry, recommended to the chairman of the Planning and Compensation Committee the appropriate base salaries for the upcoming year, other than for Mr. Nicklin. Additionally, Mr. Foran also recommended the bonuses for the Named Executive Officers, other than Mr. Nicklin, to the chairman of the Planning and Compensation

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Committee for 2009. Mr. Foran, however, did not make any recommendations regarding his own compensation. Mr. Foran and the chairman of the Planning and Compensation Committee discussed Mr. Foran s evaluation of the other Named Executive Officers, other than Mr. Nicklin, and made any appropriate adjustments to the recommended base salaries and bonuses for such other Named Executive Officers. The chairman of the Planning and Compensation Committee and Mr. Foran made their joint recommendations to both the Planning and Compensation Committee and the board of directors. However, Mr. Foran was not present when the chairman of the Planning and Compensation Committee made his recommendations regarding Mr. Foran s base salary and bonus. After receiving the recommendations from Mr. Foran and the chairman of the Planning and Compensation Committee for the other Named Executive Officers, other than Mr. Nicklin, and from the chairman of the Planning and Compensation Committee for Mr. Foran, the Planning and Compensation Committee and the board of directors unanimously (other than with respect to Mr. Foran as to his compensation) agreed with the recommendations. For 2010, the members of the Planning and Compensation Committee were Messrs. Foran, Laney, Ryan and Scott and Dr. Holditch.

Unlike the base salaries and bonuses, the equity grants to Named Executive Officers were not determined at a precise time or through a specific process. As described below under Stock Options, on February 22, 2010, stock options were granted to the Named Executive Officers based on the evaluation of each Named Executive Officer s performance and relative contributions to our growth during 2008 and 2009 by Mr. Foran in consultation with the chairman of the Planning and Compensation Committee. The members of the Planning and Compensation Committee and the board of directors unanimously agreed with the recommendations of Mr. Foran and the chairman of the Planning and Compensation Committee.

2010 General

As a private company, we did not use compensation consultants or benchmark against any other companies in determining the compensation of our Named Executive Officers for 2010. In addition, during 2010, in order to conserve cash, we attempted to maintain a modest level of compensation while still providing sufficient compensation to preserve and maintain our executive team. Through the process described above under Compensation Discussion and Analysis How We Determined Each Element of 2010 Compensation, in December 2009, the 2010 base salaries and the 2009 bonuses were determined.

2010 Base Salary

For 2010, in light of the bonuses paid at the end of 2009 and the desire to examine our results for 2010, the base salaries for the Named Executive Officers, other than Mr. Nicklin, were not changed and were maintained as follows:

Executive Officer	**2010 Base Salary**
Joseph Wm. Foran Chairman of the Board, Chief Executive Officer and President	$ 240,000
David E. Lancaster Executive Vice President, Chief Operating Officer and Chief Financial Officer	$ 240,000
Matthew V. Hairford Executive Vice President Operations	$ 240,000
Bradley M. Robinson Vice President Reservoir Engineering	$ 200,000

Although Mr. Nicklin is retained officially as a consultant, he serves as our Executive Director of Exploration and is included and treated as a Named Executive Officer for the purposes of this prospectus. Mr. Nicklin retired in 2000 as the Chief Geologist for ARCO and desires to maintain a measure of

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independence and flexibility in his schedule. Under this consulting arrangement, we are able to obtain the benefit of his experience and expertise that we would otherwise not have. For 2010, Mr. Foran determined that Mr. Nicklin s base rate should remain at $1,500 per day. As with other Named Executive Officers, Mr. Nicklin s base rate was not increased in 2010 due to our desire to maintain a modest level of compensation and to examine our results for 2010 prior to any further increases in his base rate being made. His 2010 compensation based on his base rate was $315,000.

2010 Stock Options

As mentioned above under Compensation Discussion and Analysis How We Determined Each Element of 2010 Compensation, in February 2010, since we had not issued any stock options to the Named Executive Officers since February 2008, Mr. Foran recommended to the chairman of the Planning and Compensation Committee that stock options be granted to the Named Executive Officers in order to help maintain their focus on our long-term success. On February 22, 2010, the stock options set forth below were granted to the Named Executive Officers pursuant to the 2003 Stock and Incentive Plan (the 2003 Plan), other than Mr. Foran, since it has been Mr. Foran s practice since our founding to refuse to accept any stock options so that our other employees may receive more options:

Executive Officer	**2010 Stock Options**
David E. Lancaster Executive Vice President, Chief Operating Officer and Chief Financial Officer	Exercisable into 15,000 shares of Class A common stock
Matthew V. Hairford Executive Vice President Operations	Exercisable into 10,000 shares of Class A common stock
David F. Nicklin Executive Director of Exploration	Exercisable into 10,000 shares of Class A common stock
Bradley M. Robinson Vice President Reservoir Engineering	Exercisable into 5,000 shares of Class A common stock

The number of stock options awarded to each Named Executive Officer was based upon an evaluation of each Named Executive Officer s performance and relative contributions to our growth over the previous two years, 2008 and 2009, as determined by Mr. Foran in consultation with the chairman of the Planning and Compensation Committee. The Named Executive Officers stock option awards reflected each officer s contributions to the following company-wide accomplishments:

- increasing our annual production to approximately 5.0 Bcfe for the year ended December 31, 2009 from approximately 3.3 Bcfe for the year ended December 31, 2008;
- more than doubling our average daily production to 23.8 MMcfe per day for the month of December 2009 as compared to 9.6 MMcfe per day for the month of December 2008; and
- increasing our proved oil and natural gas reserves by more than three-fold to 64.5 Bcfe at December 31, 2009 from 20.0 Bcfe at December 31, 2008.

In addition to their contributions towards meeting the above objectives, the Named Executive Officers stock option awards reflected the following individual contributions:

Mr. Lancaster s specific contributions to the closing of the Chesapeake transaction in 2008 and his efforts related to planning the strategic reinvestment of the proceeds from the transaction;

Mr. Hairford s efforts in planning and conducting our 2008 and 2009 Cotton Valley drilling and completion program in north Louisiana, for the cost savings achieved in that program on a well-by-well basis and for his leadership of the operations and land staff in saving key leasehold tracts set to expire in 2008 in our Elm Grove/Caspiana area;

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- Mr. Robinson s efforts in planning and conducting our 2008 and 2009 Cotton Valley drilling and completion program in north Louisiana; and

- Mr. Nicklin s leadership of the exploration staff in identifying the Eagle Ford shale as a potential new exploration play for the company.

The members of the Planning and Compensation Committee and the board of directors unanimously agreed with the recommendations of Mr. Foran and the chairman of the Planning and Compensation Committee.

The stock options vest 25% on each of the first four anniversaries of February 22, 2010 if the Named Executive Officer is then still employed by us or is still a consultant for us with regard to Mr. Nicklin. The exercise price of the stock options is $9.00 per share which we determined was the fair market value of our Class A common stock on February 22, 2010. The options expire on the tenth anniversary of their grant date.

2010 Cash Bonuses

In December 2010, Mr. Foran evaluated the Named Executive Officers, and, based on his knowledge of compensation levels in the oil and natural gas industry, recommended to the chairman of the Planning and Compensation Committee the appropriate 2010 bonuses for the Named Executive Officers, other than himself. The reasons we paid discretionary cash bonuses to our executive officers in 2010 are described above under Compensation Discussion and Analysis Elements of Our 2010 Compensation Program and Why We Pay Each Element Discretionary Cash Bonuses. Mr. Foran and the chairman of the Planning and Compensation Committee discussed Mr. Foran s evaluation of the Named Executive Officers and made any appropriate adjustments to the recommended bonuses. The amounts of the bonuses for each Named Executive Officer were based upon an evaluation of each Named Executive Officer s performance and contributions to our growth and achievement of our performance objectives in 2010 considered in relation to all elements of the Named Executive Officer s overall compensation. The Named Executive Officers cash bonuses in 2010 reflected each officer s contributions to meeting our company-wide 2010 performance objectives which included the following:

- increasing proved oil and natural gas reserves at December 31, 2010 to at least 100 Bcfe, a target we exceeded by increasing our proved oil and natural gas reserves at December 31, 2010 to 128.3 Bcfe;

- increasing annual production for 2010 to at least 8 Bcfe, a target we exceeded by increasing our annual production for 2010 to 8.6 Bcfe;

- reducing operating cash costs (excluding unit depletion, depreciation and amortization costs) below $2.00 per Mcfe in 2010, a target we achieved by realizing operating cash costs of $1.97 per Mcfe in 2010;

- making a significant discovery in a new exploration play, a target we achieved with the drilling of our first operated Eagle Ford shale wells; and

- securing a joint venture participant for the exploration of the Meade Peak shale in southwest Wyoming and adjacent areas in Utah and Idaho, a target we achieved with the closing of our participation agreement with Alliance Capital Real Estate, Inc. in May 2010.

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Also, the Named Executive Officers cash bonuses reflected each officer s contributions to the successful acquisition of additional leasehold acreage in both the Haynesville and Eagle Ford plays throughout 2010. In addition to their contributions toward meeting the above objectives and the acquisition of additional Haynesville and Eagle Ford acreage, the Named Executive Officers cash bonuses in 2010 reflected the following individual contributions:

Mr. Foran s efforts in the successful outcome of our October 2010 through January 2011 private placement offering of 1,922,199 shares of our Class A common stock and the leadership he provided to the attainment of our 2010 performance objectives identified above;

Mr. Lancaster s efforts in the increase in the borrowing base under our credit agreement from $20,000,000 to $55,000,000 in 2010 and the leadership he provided to the attainment of our 2010 operational and financial objectives identified above;

Mr. Hairford s bonus included a special performance bonus of $50,000 in recognition of Mr. Hairford s effort to negotiate and consummate the acquisition of approximately 8,892 gross and net acres in the Eagle Ford play in Zavala County, Texas and his bonus also reflected his efforts in the successful drilling and completion of our first operated wells in the core area of the Haynesville shale and in the Eagle Ford shale;

Mr. Nicklin s leadership of the exploration staff in developing in-house processes for the geosteering of long, horizontal laterals in the Eagle Ford and Haynesville plays and his specific contributions to securing the joint participation agreement with Alliance Capital Real Estate, Inc. for the exploration of our Meade Peak shale prospect; and

Mr. Robinson s specific contributions to identifying Alliance Capital Real Estate, Inc. as a potential joint venture partner for the exploration of our Meade Peak shale prospect and for assuming the leadership role in coordinating our non-operated participation interests in the Haynesville play in north Louisiana.

The chairman of the Planning and Compensation Committee and Mr. Foran made their joint recommendations of the bonus amount to both the Planning and Compensation Committee and the board of directors. However, Mr. Foran was not present when the chairman of the Planning and Compensation Committee made his recommendations regarding Mr. Foran s bonus. After receiving the recommendations from Mr. Foran and the chairman of the Planning and Compensation Committee for the other Named Executive Officers and from the chairman of the Planning and Compensation Committee for Mr. Foran, the Planning and Compensation Committee and the board of directors unanimously (other than with respect to Mr. Foran on his bonus) agreed with the recommendations.

Executive Officer	**2010 Bonus**
Joseph Wm. Foran Chairman of the Board, Chief Executive Officer and President	$ 400,000
David E. Lancaster Executive Vice President, Chief Operating Officer and Chief Financial Officer	$ 100,000
Matthew V. Hairford Executive Vice President Operations	$ 150,000(1)
David F. Nicklin Executive Director of Exploration	$ 35,000
Bradley M. Robinson Vice President Reservoir Engineering	$ 50,000

(1) Includes the $50,000 special performance bonus described above.

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Benefits

We offer a variety of health and welfare programs to all eligible employees, including the executive officers other than Mr. Nicklin. The health and welfare programs are intended to protect employees against catastrophic loss and encourage a healthy lifestyle. Our health and welfare programs include medical, pharmacy, dental, disability and life insurance. We also have a 401(k) plan for all full time employees, including the executive officers, other than Mr. Nicklin, in which we contribute 3% of the employee s base salary and have the discretion to match dollar-for-dollar up to an additional 4% of the employee s elective deferral contributions. We generally do not offer perquisites to our executives, including our Named Executive Officers. However, we guaranteed the repayment of loans to certain of our Named Executive Officers by Comerica Bank. We intend on terminating our guaranties of such loans on or before , 2012 (See Certain Relationships and Related Party Transactions Loan Program).

2011

Nominating, Compensation and Planning Committee

In consideration of becoming a public company, we formed the Nominating, Compensation and Planning Committee of our board of directors and adopted a charter for such committee which provides a new process for approving compensation of the Named Executive Officers. The Nominating, Compensation and Planning Committee has the authority at our expense to retain and terminate independent third-party compensation consultants and other expert advisors. In addition, the Nominating, Compensation and Planning Committee will confirm at least annually that our incentive pay does not encourage unnecessary risk taking and review and discuss the relationship between risk management policies and practices, corporate strategy and senior executive compensation.

With regard to all of the Named Executive Officers, the Nominating, Compensation and Planning Committee will recommend to the independent members of our board of directors (the Independent Directors):

- option guidelines and size of overall grants;
- option grants and other equity and non-equity related awards; and
- modifications or cancellations of existing grants and substitutions of new grants.

The Independent Directors are required to be independent pursuant to the listing standards of the NYSE and the rules and regulations promulgated under the Exchange Act and Section 162(m) of the Internal Revenue Code of 1986, as amended (the Code).

The Nominating, Compensation and Planning Committee will annually review and make recommendations to the Independent Directors regarding the matters related to Mr. Foran s compensation including corporate goals and objectives applicable to Mr. Foran s compensation. The Nominating, Compensation and Planning Committee will also evaluate Mr. Foran s performance in light of these established goals and objectives at least annually. Based upon these evaluations, the Nominating, Compensation and Planning Committee will make recommendations to the Independent Directors regarding Mr. Foran s annual compensation, including salary, bonus and equity and non-equity incentive compensation. The Nominating, Compensation and Planning Committee will review and recommend to the Independent Directors with regard to Mr. Foran:

- any employment agreement, severance agreement, change in control agreement or provision or separation agreement or amendment thereof;

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- any deferred compensation arrangement or retirement plan or benefits; and
- any benefits and perquisites.

On an annual basis, after consultation with Mr. Foran, the Nominating, Compensation and Planning Committee will review and make recommendations to the Independent Directors on the evaluation process and compensation structure for the other Named Executive Officers. After considering the evaluation and recommendations of Mr. Foran, the Nominating, Compensation and Planning Committee will evaluate the performance of the other Named Executive Officers and make recommendations to the Independent Directors regarding the annual compensation of such Named Executive Officers, including salary, bonus and equity and non-equity incentive compensation.

After considering the recommendations of Mr. Foran with regard to the other Named Executive Officers, the Nominating, Compensation and Planning Committee will review and recommend to the Independent Directors regarding the other executive officers:

- any employment agreement, severance agreement, change in control agreement or provision or separation agreement or amendment thereof;
- any deferred compensation arrangement or retirement plan or benefits; and
- any benefits and perquisites.

In addition, pursuant to its charter, the Nominating, Compensation and Planning Committee will review and recommend to the Independent Directors any proposals for the adoption, amendment, modification or termination of our incentive compensation, equity based plans and non-equity based plans.

How We Determine Each Element of 2011 Compensation

2011 General

In consideration of becoming a public company and in connection with this offering, the Planning and Compensation Committee (a predecessor committee to the Nominating, Compensation and Planning Committee) engaged Pay Governance LLC as its independent executive compensation advisory firm to assist with the development and implementation of a new executive compensation program which we originally anticipated would become effective upon the completion of this offering.

For purposes of benchmarking executive compensation, Pay Governance LLC developed a list of recommended peer companies in the oil and gas exploration and production sector. These companies were recommended to and approved by the Planning and Compensation Committee based on their annual revenues, market capitalization, enterprise value, total assets and EBITDA (earnings before interest, taxes, depletion, depreciation and amortization). The 2011 compensation peer companies are as follows:

Bill Barrett Corp.	Petroleum Development Corp.
Breitburn Energy Partners, L.P.	Rosetta Resources, Inc.
Clayton Williams Energy Inc.	Stone Energy Corp.
Comstock Resources Inc.	Swift Energy Co.
Contango Oil & Gas Co.	Unit Corporation
Gulfport Energy Company	Venoco, Inc.
Penn Virginia Corp.	W&T Offshore, Inc.

Mr. Foran was compared against the chief executive officer position of all fourteen peer companies. Mr. Lancaster was compared against the average of the chief financial officer position and the second

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highest paid position based on annual cash compensation of the fourteen peer companies. Messrs. Hairford, Nicklin and Robinson were compared against the third, fourth and fifth highest paid positions based on annual cash compensation of the peer companies, respectively. However, Gulfport Energy Company did not have a fourth and fifth highest paid position and Contango Oil and Gas Co. and Venoco Inc. did not have a fifth highest paid position. The data regarding the peer comparison is based on information presented in their 2010 filings regarding compensation for the year ended December 31, 2009 except for Contango Oil and Gas Co., which had a June 30, 2010 year-end.

As an overall compensation philosophy for 2011, we decided to adopt conservative pay levels as an initial strategy of being a public company. As we grow and build value for our shareholders through sustained high performance and shareholder returns, we plan to increase our overall compensation pay levels gradually toward the 50^{th} percentile of our peer group. In developing our public company compensation program for 2011, we adopted a strategy of focusing on the 25^{th} percentile (lowest quartile) as a general target range for benchmarking most of our Named Executive Officer compensation. Initially for 2011, all elements of direct compensation, including base salary, annual incentive compensation and long-term incentive compensation were targeted for most of our Named Executive Officers to provide pay opportunities in the range of the 25^{th} percentile of our peer companies; however, as described below, based on the timing of this offering, the Nominating, Compensation and Planning Committee and the Independent Directors (both of which are currently comprised of the same members) modified the timing of the increases in certain base salaries, determined not to use a formulaic cash incentive program for 2011 and determined not to make any equity grants to Named Executive Officers for 2011.

2011 Base Salary

For most of 2011, except for Mr. Robinson, the base salaries for our Named Executive Officers remained at their 2010 levels. Mr. Robinson s base salary was increased effective January 1, 2011 to $225,000. Originally, the base salaries for the Named Executive Officers other than Mr. Robinson were to be increased to the following amounts upon the completion of this offering:

Mr. Foran $550,000

Mr. Lancaster $340,000

Mr. Hairford $275,000

Mr. Nicklin $2,000 per day of which $250 per day will be deferred until the end of the three year independent contractor agreement; provided Mr. Nicklin s engagement continues until that point. Payments will actually be made to his consulting company.

However, due to the timing of this offering, the Nominating, Compensation and Planning Committee and the Independent Directors determined to make the increases set forth above effective for Messrs. Lancaster, Hairford and Nicklin on December 1, 2011, and for Mr. Foran effective January 1, 2012. Mr. Foran s increased base salary was set between the 25^{th}-50^{th} percentiles of base compensation levels of the peer companies. The increased base salaries for all other Named Executive Officers were set in the range of the 25^{th} percentile of the peer companies for positions indicated above.

2011 Cash Bonuses

Although we had originally planned to adopt an Annual Incentive Plan for 2011 and to make the 2011 incentive payments based on the Annual Incentive Plan, due to the timing of this offering, the board of directors decided to adopt the Annual Incentive Plan effective January 1, 2012 and to make our incentive payments for 2012 performance under the Annual Incentive Plan as described below under 2012 Annual Incentive Compensation.

For the 2011 cash bonuses, a sub-committee of the Nominating, Compensation and Planning Committee and the Independent Directors is planning to make recommendations regarding such bonuses for the Named Executive Officers to the Nominating, Compensation and Planning Committee and the Independent Directors in February 2012, and then the Nominating, Compensation and Planning Committee and the Independent Directors are planning to determine the amounts of the cash bonuses to be paid to the Named Executive Officers. Although there are not any formulaic plans for determining the 2011 cash bonuses, the Nominating, Compensation and Planning Committee and the Independent Directors anticipate that the rationale for the cash bonus to be paid to each Named Executive Officer will be based on both the company-wide 2011 performance and the applicable Named Executive Officer s individual 2011 contribution as determined by the Nominating, Compensation and Planning Committee and the Independent Directors in a manner similar to the 2010 stock options grants and the 2010 cash bonuses.

In addition, to reward Messrs. Foran, Lancaster and Hairford for their valuable contributions in the preparation of this offering, the Planning and Compensation Committee (a predecessor committee to the Nominating, Compensation and Planning Committee) authorized a bonus payment to them of $50,000, $40,000 and $20,000, respectively. In 2011, the Nominating, Compensation and Planning Committee and the Independent Directors ratified such bonus payments.

Finally, pursuant to the terms of Mr. Nicklin s independent contractor agreement, if the board of directors determines that he has fulfilled his duties in a reasonably satisfactory manner, his consulting company will be paid a bonus of at least $50,000 for 2011.

2011 Long-Term Incentive Compensation

Although the Nominating, Compensation and Planning Committee and the Independent Directors had originally planned to make equity grants to the Named Executive Officers in 2011 consisting of non-qualified stock options, performance shares and time-lapsed restricted shares, the Nominating, Compensation and Planning Committee and the Independent Directors decided not to make any equity grants to Named Executive Officers in 2011 due to the timing of this offering.

How We Determine Each Element of 2012 Compensation

2012 Base Salary

For 2012, after receiving input from Mr. Foran, the Nominating, Compensation and Planning Committee and the Independent Directors decided to leave the salaries for Messrs. Foran, Lancaster and Nicklin at the amounts set forth above after giving effect to the increase in Mr. Foran s base salary to $550,000 beginning on January 1, 2012. With regard to Messrs. Hairford and Robinson, after receiving input from Mr. Foran, the Nominating, Compensation and Planning Committee and the Independent Directors decided to increase the base salaries effective January 1, 2012 for Mr. Hairford to $300,000 and for Mr. Robinson to $240,000. Mr. Hairford s raise was based upon his role in completing our Eagle Ford acreage acquisition in Dewit, Karnes, Wilson and Gonzales counties and for his leadership in initiating our ongoing drilling and completion operations in the Eagle Ford shale. Mr. Robinson s raise was based upon his ongoing leadership in coordinating our non-operating participation interests in the Haynesville shale and

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elsewhere and for his specific technical contributions to our completion operations in the Eagle Ford shale and our exploration efforts in the Meade Peak shale.

2012 Annual Incentive Compensation

Effective January 1, 2012, we adopted an Annual Incentive Plan. All awards made pursuant to the Annual Incentive Plan will be cash awards. Such awards will be paid to the Named Executive Officers as soon as practical following completion of the plan year and, in any case, within the first 135 days following the end of the plan year.

Each year, the Nominating, Compensation and Planning Committee will recommend to the Independent Directors and the Independent Directors will set annual performance criteria for the Named Executive Officers based on the possible performance criteria that are set forth in the Annual Incentive Plan. Such criteria may include financial, operational and strategic performance goals for the company, company performance measures and company performance relative to peers. The Nominating, Compensation and Planning Committee will also recommend to the Independent Directors and the Independent Directors will set corresponding performance payment amounts based on the achievement of such performance criteria by each Named Executive Officer.

In addition to the annual performance criteria, in order to give the Nominating, Compensation and Planning Committee and the Independent Directors flexibility, the Nominating, Compensation and Planning Committee may make recommendations to the Independent Directors and the Independent Directors may decide after completion of our fiscal year to decrease the amount of the payments relating to the corresponding performance criteria or to increase the amount of the payments to the Named Executive Officers. Any increase may be in response to unforeseen circumstances when the performance criteria were set. Any such increase may or may not be based on the list of performance criteria set forth in the Annual Incentive Plan and may be made irrespective of whether any payments are made regarding the performance criteria.

For 2012, we plan to utilize performance criteria which may include, without limitation, such items as production volumes, oil and natural gas reserves added, EBITDA, finding costs and lease operating expenses as well as environmental compliance measures and safety and accident rates. In February 2012, we anticipate that a sub-committee of the Nominating, Compensation and Planning Committee and Independent Directors (the Nominating, Compensation and Planning Committee and the Independent Directors are currently comprised of the same members) will recommend to the Nominating, Compensation and Planning Committee and the Independent Directors and the Nominating, Compensation and Planning Committee and the Independent Directors will determine the threshold, target and maximum performance measures for the selected performance criteria, the weighting of such criteria in comparison to the other performance criteria and the corresponding annual incentive opportunity expressed as a percentage of base salary for each Named Executive Officer for the threshold, target and maximum performance criteria levels. In future years, we may add more quantitative performance criteria to the measurement in order to better measure Named Executive Officer contributions to our performance.

The threshold opportunity will be aligned with the performance goals established for each Named Executive Officer, such that meeting the threshold level of all performance criteria may result in the Named Executive Officer earning his threshold annual incentive opportunity set forth under the performance criteria. The target opportunity will be aligned with the performance goals established for each Named Executive Officer, such that meeting the target level for all of the performance criteria may result in the Named Executive Officer earning his target annual incentive opportunity set forth under the performance

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criteria. The maximum opportunity will be aligned with the performance goals established for each Named Executive Officer, such that meeting the maximum level of all performance criteria may result in the Named Executive Officer earning his maximum annual incentive opportunity set forth under the performance criteria. The table which follows sets forth the anticipated threshold, target and maximum incentive opportunities for the Named Executive Officers for 2012 based on the to be selected performance criteria.

Participant	Threshold Annual Incentive Opportunity as % of 2012 Base Salary	Target Annual Incentive Opportunity as % of 2012 Base Salary	Maximum Annual Incentive Opportunity as % of 2012 Base Salary
Joseph Wm. Foran Chairman of the Board, Chief Executive Officer and President	37.5%	75%	150%
David E. Lancaster Executive Vice President, Chief Operating Officer and Chief Financial Officer	32.5%	65%	130%
Matthew V. Hairford Executive Vice President Operations	32.5%	65%	130%
David F. Nicklin Executive Director of Exploration	25%	50%(1)	100%
Bradley M. Robinson Vice President Reservoir Engineering	25%	50%	100%

(1) The target annual incentive opportunity, expressed in dollars, assumes that Mr. Nicklin works 210 days per year at the rate of $2,000 per day. Payments will actually be made to his consulting company.

In early 2013, with regard to each Named Executive Officer, after taking into account the performance criteria and all other information with regard to such Named Executive Officer, the Nominating, Compensation and Planning Committee (or sub-committee thereof) may recommend to the Independent Directors that any Named Executive Officer be paid an annual award and the Independent Directors will determine the annual award to be paid to such Named Executive Officer, if any. The amount of such annual award may be greater than or less than the payment opportunity based on the performance criteria so long as the annual award does not exceed 200% of the applicable Named Executive Officer s annual base salary.

Long-Term Incentive Plan

Effective January 1, 2012, the board of directors adopted the 2012 Long-Term Incentive Plan. This plan permits the granting of long-term equity and cash incentive awards, including the following:

- stock options;
- stock appreciation rights;
- restricted stock (time-lapse and performance-based);

restricted stock units (both time-lapse and performance-based);

performance shares;

performance units;

stock grants; and

performance cash awards.

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The 2012 Long-Term Incentive Plan has 4,000,000 shares of common stock or share equivalents reserved for issuance. The plan covers grants to the Named Executive Officers, key employees, consultants and non-employee directors.

After receiving recommendations from the Nominating, Compensation and Planning Committee (or a sub-committee thereof), the plan will be administered by the Independent Directors, who will authorize and approve grants, including the size and terms of such grants such as vesting and the lapsing of restrictions. For 2012, the Independent Directors anticipate that the Named Executive Officers will receive non-qualified stock options, performance shares and time-lapsed restricted shares with each type of grant for each Named Executive Officer having a present value equal to one-third of the value of all long-term incentive compensation awarded during 2012 to such Named Executive Officer. Mr. Nicklin s grants will be made to his consulting company.

The stock options will be granted at 100% of fair market value of our common stock on the date of grant and will vest equally on the first four anniversaries of the grant date if the Named Executive Officer is still employed by us on such dates. The Independent Directors anticipate that the performance shares will be subject to a three-year performance period following the date of grant, and the number of performance shares earned by each participant may range from 0% to 200% of the shares granted subject to performance criteria if the Named Executive Officer is still employed by us at the end of the three-year performance period or an independent contractor with us with regard to Mr. Nicklin. The Independent Directors expect the performance criteria will be our total shareholder return relative to the peer companies set forth above as measured by the increase in share price over the three-year performance period plus the value of dividends (reinvested in an equivalent value of shares at the end of the month if and when any dividends are declared). The Independent Directors believe if our total shareholder return is equal to the 50^{th} percentile of the total shareholder return of the peer companies, then the Named Executive Officer will earn 100% of the shares granted. The Independent Directors believe if our total shareholder return is equal to the 75^{th} percentile of the peer companies, the Named Executive Officer will earn 150% of the performance shares granted. The Independent Directors believe if our total shareholder return is equal to 90% or greater of the peer companies, the Named Executive Officer will receive 200% of the performance shares granted. The Independent Directors believe if our total shareholder return is below the 35^{th} percentile of the peer companies, the Named Executive Officer will not earn any of the performance shares granted. The Independent Directors expect the number of shares earned between the 35^{th} percentile and the 50^{th} percentile, the 50^{th} percentile and the 75^{th} percentile and the 75^{th} percentile and the 90^{th} percentile will be on a straight line interpolation basis. The Independent Directors anticipate the restrictions on the time-lapsed restricted shares will lapse equally on the first three anniversaries of the grant date if the Named Executive Officer is still employed with us on such dates. During the restricted period, the Named Executive Officer will be eligible to receive dividends on and vote the restricted shares.

How Elements of Our Compensation Program Are Related to Each Other

We view the various components of compensation as related but distinct with generally a significant portion of total compensation reflecting pay for performance. We do not have any formal or informal policies or guidelines for allocating compensation between long-term and currently paid out compensation or between cash or non-cash compensation.

Accounting and Tax Considerations

Under Section 162(m) of the Code, a limitation is placed on tax deductions of any publicly-held corporation for individual compensation to certain executives of such corporation exceeding $1.0 million in

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any taxable year, unless the compensation is performance based. Since we have not been a publicly-held company, Section 162(m) has not applied to us, and there is an exception to this deductibility limitation for a specified period of time in the case of companies such as us that become publicly-held.

Termination of Employment Arrangements and Independent Contractor Agreement

Employment Agreements and Independent Contractor Agreement

For 2010 and until August 8, 2011, all of the Named Executive Officers other than Messrs. Foran and Nicklin were parties to employment agreements which provided for at will employment with either party being required to provide two weeks advanced notice of termination of employment. These employment agreements did not provide for any additional payments upon termination by either party, even after a change in control, other than accrued and unused vacation. For 2010 and until August 8, 2011, Mr. Nicklin was party to an independent contractor agreement which provided for either party being required to provide fifteen days advance notice of termination. This consulting agreement did not provide for any additional payments upon termination by either party, even after a change in control, other than for services performed prior to the date of termination.

As described under Discussion Regarding Summary Compensation Table and Grants of Plan-Based Awards Table, in contemplation of this offering, on August 9, 2011, we entered into employment agreements with Messrs. Foran, Lancaster, Hairford and Robinson and an independent contractor agreement with Mr. Nicklin and his consulting company.

Under the employment agreements, if one of the following occurs:

- the Named Executive Officer dies;
- the Named Executive Officer is totally disabled;
- we mutually agree to end the employment agreement;
- we dissolve and liquidate; or
- the term of the employment agreement ends,

we will pay the Named Executive Officer the average of his annual bonus for the prior two years pro-rated based on the number of complete or partial months completed during the year of termination.

Also, under the employment agreements, if one of the following occurs:

- the Named Executive Officer is terminated (i) by us for a reason other than (a) as set forth above or (b) for just cause, or (ii) in connection with a change in control as described below; or
- the Named Executive Officer terminates his employment for good reason,

if the Named Executive Officer is Mr. Foran, we will pay him twice his base salary and twice the average of his annual bonus for the prior two years; if the Named Executive Officer is Messrs. Lancaster or Hairford, we will pay him 1.5 times his base salary and 1.5 times the average of his annual bonus for the prior two years; and if the Named Executive Officer is Mr. Robinson, we will pay him one year of base salary and the average of his annual bonus for the prior two years.

Finally, under the employment agreements, upon a change in control and within 30 days prior to the change in control or within 12 months after the change in control, if we terminate a Named Executive

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Officer without just cause or the Named Executive Officer terminates his employment with or without good reason, if the Named Executive Officer is Messrs. Foran, Lancaster or Hairford, we will pay him three times his base salary and three times the average of his annual bonus for the prior two years; and if the Named Executive Officer is Mr. Robinson, we will pay him twice his base salary and twice the average of his annual bonus for the prior two years.

Change in control is defined under Section 409A of the Code as follows:

- A change in ownership of the company occurs on the date that, except in certain situations, results in someone acquiring more than 50% of the total fair market value or voting power of the company s stock;

- A change in effective control of the company occurs on one of the following dates:

  - The date that a person acquires (or has acquired in a 12 month period) ownership of 30% or more of the company s total voting power; however, if a person already owns at least 30% of the company s total voting power, the acquisition of additional control does not constitute a change in control; or

  - The date during a 12 month period where a majority of the company s board of directors is replaced by directors whose appointment or election was not endorsed by a majority of the board of directors; and

- A change in the ownership of a substantial portion of the company s assets occurs on the date a person acquires (or has acquired in a 12 month period) assets of the company having a total gross market value of at least 40% of the total gross fair market value of all of the company s assets immediately before such acquisition.

For purposes of the employment agreements, good reason means:

- The assignment of duties inconsistent with the title of the Named Executive Officer or his current office or a material diminution of the Named Executive Officer s current authority, duties or responsibilities;

- A diminution of the Named Executive Officer s base salary or a material breach of the employment agreement; or

- The relocation of the company s principal executive offices more than 30 miles from the company s present principal executive offices or the transfer of the Named Executive Officer to a place other than the company s principal executive offices; and

- The action causing the good reason is not cured within the applicable cure period.

For purposes of the employment agreements, just cause means:

- The Named Executive Officer s continued and material failure to perform the duties of his employment consistent with his position other than due to disability;

The Named Executive Officer s failure to perform his material obligations under the employment agreement other than due to disability;

The Named Executive Officer s material breach of the company s written policies concerning discrimination, harassment or securities trading;

The Named Executive Officer s refusal or failure to follow lawful directives of the board of directors and any supervisors other than due to disability;

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- The Named Executive Officer s commission of fraud, theft or embezzlement;
- The Named Executive Officer s conviction or indictment of a felony or other crime involving moral turpitude; or
- The Named Executive Officer s intentional breach of fiduciary duty; and
- The action causing the just cause is not cured within the applicable cure period.

Under Mr. Nicklin s independent contractor agreement, if one of the following occurs:

- he dies;
- he is totally disabled;
- we mutually agree to end the independent contractor agreement;
- we dissolve and liquidate; or
- the term of the independent contractor agreement ends,

we must pay his consulting company (i) the average of the annual bonus paid to the consulting company for the prior two years pro-rated based on the number of complete or partial months completed during the year of termination and (ii) all accrued and vested compensation under our incentive plans. In addition, if Mr. Nicklin dies or is totally disabled during the three year term of the independent contractor agreement, his consulting company will be paid $250 per day that Mr. Nicklin consulted for us during the term of the independent contractor agreement.

Also, under the independent contractor agreement, if one of the following occurs:

- the independent contractor agreement is terminated by us for a reason other than as set forth above or in connection with a change in control as described below; or
- he terminates the independent contractor agreement for good reason (as described in connection with the employment agreements set forth above),

we must pay an amount equal to $1,000 per full business day for the lesser of (i) the time Mr. Nicklin consulted for us during the prior twelve months of the term of the independent contractor agreement or (ii) the time between August 9, 2011 and the date the independent contractor agreement was terminated plus accrued and vested compensation under our equity plans.

Finally, under the independent contractor agreement, upon a change in control (as described in connection with the employment agreements set forth above) and within 30 days prior to the change in control or within 12 months after the change in control, if we terminate Mr. Nicklin without just cause (as described in connection with the employment agreements set forth above) or Mr. Nicklin terminates his independent contractor agreement with or without good reason, we will pay an amount equal to two times the aggregate amount paid based on the daily rate during the prior twelve months plus accrued and vested compensation under our equity plans.

Equity Plans

The 2003 Plan provides that all awards automatically vest upon a change in control.

See the definition of change in control under Potential Payments upon Termination or Change in Control.

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The change in control provisions in the employment agreements, the independent contractor agreement and the 2003 Plan help prevent management from being distracted by rumored or actual changes in control. The change in control provisions provide:

- incentives for the Named Executive Officers to remain with us despite the uncertainties of a potential or actual change in control;
- assurance of severance payments for terminated Named Executive Officers; and
- access to equity compensation after a change in control.

We believe a single trigger is appropriate for the following reasons:

- to be competitive with what we believe to be the standards for payments upon a change in control ;
- with regard to equity, employees or independent contractors who remain after a change in control are treated the same as the general shareholders who could sell or otherwise transfer their equity upon a change in control ; and
- since we would not exist in our present form after a change in control, Named Executive Officers should not have to have their compensation dependent on the new company.

Stock Ownership Guidelines

We have adopted stock ownership guidelines for our executive officers that cover the following executive officers and designated amounts:

- Chairman, President and Chief Executive Officer shares equal to five times base salary;
- Executive Vice Presidents shares equal to two and $^1/2$ times base salary; and
- Vice Presidents and Executive Directors shares equal to one and $^1/2$ times base salary.

Each of the foregoing executive officers has five years from the date of the closing of this offering in which to achieve the stock ownership position. Shares which will count toward the stock ownership guidelines include time-lapse restricted shares that are still restricted and any shares held in trust by the executive officer or his immediate family over which he has direct beneficial ownership interest. Shares which will not count toward the stock ownership guidelines include shares underlying unexercised stock options, unexercised stock appreciation rights and performance-based awards for which the performance requirements have not been satisfied.

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Summary Compensation Table

The following table summarizes the total compensation awarded to, earned by or paid to Messrs. Foran, Lancaster, Hairford, Nicklin and Robinson. This table and the accompanying narrative should be read in conjunction with the Compensation Discussion and Analysis, which sets forth the objectives and other information regarding our executive compensation program.

Name and Principal Position	Year	Salary ($)	Bonus ($)	Option Awards[(1)] ($)	All Other Compensation ($)	Total ($)
Joseph Wm. Foran Chairman of the Board, Chief Executive Officer and President	2010	$ 240,000	$ 400,000		$ 17,994[(2)]	$ 657,994
David E. Lancaster Executive Vice President, Chief Operating Officer and Chief Financial Officer	2010	$ 240,000	$ 100,000	$ 46,781	$ 17,150[(3)]	$ 403,931
Matthew V. Hairford Executive Vice President Operations	2010	$ 240,000	$ 150,000	$ 31,187	$ 17,150[(3)]	$ 438,337
David F. Nicklin Executive Director of Exploration	2010	$ 315,000[(4)]	$ 35,000	$ 32,556		$ 382,556
Bradley M. Robinson Vice President Reservoir Engineering	2010	$ 200,000	$ 50,000	$ 15,594	$ 17,150[(3)]	$ 282,744

(1) Option awards are the grant date fair values computed in accordance with FASB ASC Topic 718. Our policy and assumptions made in the valuation of the stock options are contained in Note 2 and Note 8 of the audited financial statements for the year ended December 31, 2010.

(2) Consists of $17,150 in 401(k) matching contributions as described in Benefits and $844 in premiums reimbursed to Mr. Foran for a disability policy covering Mr. Foran.

(3) Consists of $17,150 in 401(k) matching contributions as described in Benefits.

(4) Based on the aggregate amount of payments made to Mr. Nicklin as determined by his base rate of $1,500 per day under his consulting agreement.

Grants of Plan-Based Awards During 2010

Shown in the table below are the stock option grants to acquire common stock made during 2010 to our Named Executive Officers under the 2003 Plan.

Name	Grant Date	Number of Securities Underlying Options (#)[(1)]	Exercise or Base Price of Option Awards ($/Sh)	Grant Date Fair Value of Option Awards ($)[(2)]
Joseph Wm. Foran				
David E. Lancaster	2/22/10	15,000	9.00	46,781
Matthew V. Hairford	2/22/10	10,000	9.00	31,187

David F. Nicklin	2/22/10	10,000	9.00	32,556
Bradley M. Robinson	2/22/10	5,000	9.00	15,594

(1) The options vest in four equal installments on each of the first, second, third and fourth anniversary of the grant date if the Named Executive Officer is employed by the company at such dates.

(2) Computed in accordance with FASB ASC Topic 718. Our policy and assumptions made in the valuation of the stock options are contained in Note 2 and Note 8 of the audited financial statements for the year ended December 31, 2010.

Discussion Regarding Summary Compensation Table and Grants of Plan-Based Awards Table

For 2010 and until August 8, 2011, all of our Named Executive Officers, other than Messrs. Foran and Nicklin, were parties to employment agreements with the company that were similar in terms with the exception of certain benefits such as salaries. Under these agreements, the employment was at will. Either party could terminate the employee s employment with or without cause at any time upon the giving of two weeks notice. There were no guaranteed payments of any kind for any of our Named Executive Officers, including Mr. Foran, in the event of a change of control. These agreements required the employee to maintain the confidentiality of our trade secrets, technical data, customer lists, training manuals, financial reports and other confidential information and knowledge regarding our business. The employee was required to deliver any property in his possession or control that is our property upon termination of employment.

For 2010 and until August 8, 2011, Mr. Nicklin was party to a consulting agreement with the company. Under this consulting agreement, Mr. Nicklin s services were subject to termination upon the giving of 15 days notice by either party. There were no guaranteed payments of any kind to Mr. Nicklin, other than reimbursement for services rendered and associated expenses through the date of termination. This agreement required Mr. Nicklin to maintain the confidentiality of our trade secrets, technical data, customer lists, training manuals, financial reports and other confidential information and knowledge regarding our business. Mr. Nicklin was required to deliver any property in his possession or control that is our property upon termination of his consulting agreement.

On August 9, 2011, we entered into employment agreements with Messrs. Foran, Lancaster, Hairford and Robinson and an independent contractor agreement with Mr. Nicklin.

Mr. Foran. His employment agreement is for a twenty-four month term and such term automatically extends each month by one additional month unless either the company or Mr. Foran gives written notice that the term will no longer be extended. The base salary is $550,000, and he is eligible to participate in our annual incentive plan and our long-term incentive plan. The base salary becomes effective upon the completion of this offering. See Compensation Discussion and Analysis Termination of Employment Arrangements and Independent Contractor Agreement Employment Agreements and Independent Contractor Agreement regarding the payments to be made to Mr. Foran upon termination of his employment and/or a change in control.

Mr. Lancaster. His employment agreement is for an eighteen month term and such term automatically extends each month by one additional month unless either the company or Mr. Lancaster gives written notice that the term will no longer be extended. The base salary is $340,000, and he is eligible to participate in our annual incentive plan and our long-term incentive plan. The base salary becomes effective upon the completion of this offering. See Compensation Discussion and Analysis Termination of Employment Arrangements and Independent Contractor Agreement Employment Agreements and Independent Contractor Agreement regarding the payments to be made to Mr. Lancaster upon termination of his employment and/or a change in control.

Mr. Hairford. His employment agreement is for an eighteen month term and such term automatically extends each month by one additional month unless either the company or Mr. Hairford gives written notice that the term will no longer be extended. The base salary is $275,000, and he is eligible to participate in our annual incentive plan and our long-term incentive plan. The base salary becomes effective upon the completion of this offering. See Compensation Discussion and Analysis Termination of Employment Arrangements and Independent Contractor Agreement Employment Agreements and Independent Contractor Agreement regarding the payments to be made to Mr. Hairford upon termination of his employment and/or a change in control.

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Mr. Robinson. His employment agreement is for a twelve month term and such term automatically extends each month by one additional month unless either the company or Mr. Robinson gives written notice that the term will no longer be extended. The base salary is $225,000, and he is eligible to participate in our annual incentive plan and our long-term incentive plan. See Compensation Discussion and Analysis Termination of Employment Arrangements and Independent Contractor Agreement Employment Agreements and Independent Contractor Agreement regarding the payments to be made to Mr. Robinson upon termination of his employment and/or a change in control.

Mr. Nicklin. His independent contractor agreement is for a thirty-six month term. The daily rate is $1,750 per day that Mr. Nicklin consults for us, and if the independent contractor agreement remains in effect until the end of the thirty-six month term, we will pay an additional $250 per day that Mr. Nicklin consulted for us during the thirty-six months. Mr. Nicklin, through his consulting company, is eligible to participate in our annual incentive plan and our long-term incentive plan. Also, for 2011, if the board of directors determines that Mr. Nicklin has fulfilled his duties in a reasonably satisfactory manner, his consulting company will be paid a bonus of at least $50,000. Any amounts Mr. Nicklin s consulting company is to be paid for 2011 as a result of the performance criteria under the annual incentive plan will be reduced by the amount of the bonus paid to such consulting company pursuant to the independent contractor agreement. The daily rate becomes effective upon the completion of this offering. See Compensation Discussion and Analysis Termination of Employment Arrangements and Independent Contractor Agreement Employment Agreements and Independent Contractor Agreement regarding the payments to be made to Mr. Nicklin s consulting company upon termination of the independent contractor agreement and/or a change in control.

Stock Options. See Compensation Discussion and Analysis How We Determined Each Element of 2010 Compensation Stock Options regarding the stock options that we granted to the Named Executive Officers in 2010, the vesting requirements and the rationale for such grants.

Bonuses. See Compensation Discussion and Analysis How We Determined Each Element of 2010 Compensation Cash Bonuses regarding the cash bonuses that we paid to the Named Executive Officers in 2010 and the rationale for such payments.

General. Base salary paid and the amount of cash bonuses paid represented from 84.2% to 97.3% of the Named Executive Officers total compensation as represented in the Summary Compensation Table with the percentages being as follows: Mr. Foran 97.3%; Mr. Lancaster 84.2%; Mr. Hairford 89.0%; Mr. Nicklin 91.5%; and Mr. Robinson 88.4%.

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Outstanding Equity Awards at December 31, 2010

The following table summarizes the total outstanding equity awards at December 31, 2010 for each Named Executive Officer:

	Option Awards			
Name	Number of Securities Underlying Unexercised Stock Options (#) Exercisable	Number of Securities Underlying Unexercised Stock Options (#) Unexercisable	Option Exercise Price ($)	Option Expiration Date
Joseph W. Foran				
David E. Lancaster	45,000	15,000	$ 9.00	2/7/12
	37,500	37,500	$ 10.00	2/12/13
		15,000	$ 9.00	2/21/20
Matthew V. Hairford	30,000		$ 9.00	7/2/11