CRIMSON EXPLORATION INC.
Form S-1/A
December 08, 2009

Table of Contents

As filed with the Securities and Exchange Commission on December 8, 2009

Registration No. 333-163277

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

Amendment No. 1
to
Form S-1

REGISTRATION STATEMENT
UNDER
THE SECURITIES ACT OF 1933

CRIMSON EXPLORATION INC.
(Exact name of registrant as specified in its charter)

Delaware	**1311**	**20-3037840**
(State or other jurisdiction of Incorporation)	*(Primary Industrial Classification Code Number)*	*(I.R.S. Employer Identification No.)*

E. Joseph Grady
Senior Vice President and Chief Financial Officer
717 Texas Avenue, Suite 2900
Houston, Texas 77002
(713) 236-7400
(Address, including zip code, and telephone number, including area code, of registrant s principal executive offices and agent for service)

Copies to:

J. Michael Chambers
Patrick J. Hurley
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1111 Louisiana Street, Suite 4400
Houston, Texas 77002
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Gillian A. Hobson
Vinson & Elkins L.L.P.
1001 Fannin Street, Suite 2500
Houston, Texas 77002
(713) 758-2222
(713) 758-2346 (fax)

Approximate date of commencement of proposed sale to the public: As soon as practical 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. o

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. o

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. o

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. o

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

CALCULATION OF REGISTRATION FEE

Title of Each Class of	Proposed Maximum Aggregate Offering	Amount of

Securities to be Registered	Price[(1) (2)]	Registration Fee[(3)]
Common Stock, $0.001 par value[(2)]	$165,600,000	$9,240

(1) Estimated solely for the purpose of calculating the amount of the registration fee pursuant to Rule 457(o) under the Securities Act of 1933, as amended.

(2) Includes shares of common stock subject to the underwriters option to purchase additional shares.

(3) $5,580 of which 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 or until this Registration Statement shall become effective on such date as the Securities and Exchange Commission, acting pursuant to said Section 8(a), may determine.

Table of Contents

The information in this preliminary prospectus is not complete and may be changed. These securities may not be sold until the registration statement filed with the Securities and Exchange Commission is effective. This preliminary prospectus is not an offer to sell nor does it seek an offer to buy these securities in any jurisdiction where the offer or sale is not permitted.

Subject to Completion, dated December 8, 2009

PROSPECTUS

18,000,000 Shares

Common Stock

We are offering 18,000,000 shares of our common stock. We have applied to list our common stock on The NASDAQ Global Market under the symbol CXPO. We anticipate that the initial public offering price per share of common stock will be between $6.00 and $8.00. Our common stock is currently traded on the Over-the-Counter Bulletin Board under the symbol CXPO.OB.

Investing in our common stock involves risks. See Risk Factors beginning on page 16.

	Per Share	Total
Price to the public	$	$
Underwriting discounts and commissions	$	$
Proceeds to us (before expenses)	$	$

We have granted the underwriters a 30-day option to purchase up to an additional 2,700,000 shares from us on the same terms and conditions as set forth above if the underwriters sell more than 18,000,000 shares of common stock in this offering.

Affiliates of certain of the underwriters are lenders under our existing revolving credit facility and therefore will receive a portion of the net proceeds of this offering.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or passed upon the adequacy or accuracy of this prospectus. Any representation to the contrary is a criminal offense.

Barclays Capital, on behalf of the underwriters, expects to deliver the shares on or about , 2009.

Barclays Capital **Credit Suisse**

Morgan Keegan & Company, Inc.

RBS
Pritchard Capital Partners, LLC
Johnson Rice & Company L.L.C.
Rodman & Renshaw, LLC
Stifel Nicolaus

Prospectus dated , 2009

TABLE OF CONTENTS

ABOUT THIS PROSPECTUS

You should rely only on the information contained in this document or to which we have referred you. We have not authorized anyone to provide you with information that is different. This document may only be used where it is legal to sell these securities. The information in this document may only be accurate on the date of this document.

Except as otherwise indicated herein or as the context otherwise requires, references in this prospectus to Crimson Exploration, Crimson, the Company, our company, we, our, and us refer collectively to Crimson Exploratio predecessor GulfWest Energy Inc. and our subsidiaries.

Our natural gas and crude oil reserve information as of December 31, 2008 and September 30, 2009 included in this prospectus is based on reserve reports prepared by Netherland, Sewell & Associates, Inc., our independent reserve engineering firm. A summary of the December 31, 2008 report is attached as Appendix B.

Unless otherwise indicated, the information contained in this prospectus assumes that the underwriters do not exercise their option to purchase additional shares from us.

Table of Contents

PROSPECTUS SUMMARY

This summary highlights information appearing elsewhere in this prospectus. Because this is a summary, it may not contain all of the information that you should consider before investing in our common stock. You should carefully read the entire prospectus, including the financial data and related notes and the information presented under the caption Risk Factors, before making an investment decision. Certain terms used in this prospectus are defined in the Glossary of Selected Terms beginning on page A-1.

Our Company

Crimson is an independent energy company engaged in the acquisition, exploitation, exploration and development of natural gas and crude oil properties. We have historically focused our operations in the onshore U.S. Gulf Coast and South Texas regions, which are generally characterized by high rates of return in known, prolific producing trends. We have recently expanded our strategic focus to include longer reserve life resource plays that we believe provide significant long-term growth potential in multiple formations.

In late 2008 and early 2009, we acquired approximately 12,000 net acres in East Texas where we completed our first well, the Kardell #1H, in October 2009. This well targeted the Haynesville Shale and initially produced 30.7 MMcfe/d, which we believe to be the highest publicly announced initial production rate to date in that formation. In addition to the Haynesville Shale, we believe this acreage is equally prospective in the Bossier Shale and James Lime formations where industry participants have drilled successful wells on adjacent acreage.

In 2007, we acquired approximately 2,800 net acres in South Texas, which we believe is prospective in the Austin Chalk and the Eagle Ford Shale. We drilled our first well on this acreage, the Dubose #1, during the fourth quarter of 2009, and we are preparing to complete the well in the Eagle Ford Shale.

We intend to grow reserves and production by developing our existing producing property base, developing our East Texas and South Texas resource potential, and pursuing opportunistic acquisitions in areas where we have specific operating expertise. We have developed a significant project inventory of over 800 drilling locations associated with our existing property base. Our technical team has a successful track record of adding reserves through the drillbit. Since January 2008, we have drilled 34 gross (15.2 net) wells with an overall success rate of 91% (excluding one well which has not yet been completed).

As of December 31, 2008, our estimated proved reserves, as prepared by our independent reserve engineering firm, Netherland, Sewell & Associates, Inc., were 131.9 Bcfe, consisting of 96.2 Bcf of natural gas and 6.0 MMBbl of crude oil, condensate and natural gas liquids. As of December 31, 2008, 73% of our proved reserves were natural gas, 69% were proved developed and 81% were attributed to wells and properties operated by us. From 2006 to 2008, we grew our estimated proved reserves from 46.4 Bcfe to 131.9 Bcfe. In addition, we grew our average daily production from 7.3 MMcfe/d for the year ended December 31, 2006 to 43.0 MMcfe/d for the nine months ended September 30, 2009. For the nine months ended September 30, 2009, we generated $55.2 million of Adjusted EBITDAX. Our definition of the non-GAAP financial measure of Adjusted EBITDAX and a reconciliation of net income (loss) to Adjusted EBITDAX are provided under Non-GAAP Financial Measures and Reconciliations. For the same period, our net income (loss) was $(16.8) million.

After application of net proceeds of approximately $117.6 million from this offering (estimated based upon the midpoint of the range of the offering price on the cover of this prospectus), we expect to have approximately $83.1 million of available borrowing capacity under our revolving credit facility to pursue our 2010 drilling program based upon $129.5 million outstanding under our revolving credit facility as of December 4, 2009. See Recent Developments Amendments to Revolving Credit Facility. Our 2010 capital budget is approximately $56 million, exclusive of acquisitions, of which we

1

expect to spend approximately 76% of our budget on our East Texas and South Texas resource plays and 24% on our existing producing assets. We plan to drill 12 gross (6.0 net) wells in 2010, including 7 gross (3.0 net) wells on our East Texas resource play acreage, one gross (0.4 net) well on our South Texas resource play acreage, and 4 gross (2.6 net) wells in Liberty County. The actual number of wells drilled and the amount of our 2010 capital expenditures will depend on market conditions, commodity prices, availability of capital and drilling and production results.

Our Strategy

The key elements of our business strategy are:

Develop our East Texas resource play. We have approximately 12,000 net acres in San Augustine and Sabine Counties of East Texas, which we believe is prospective in the Haynesville Shale, Bossier Shale and James Lime formations. In November 2009, we announced the completion and initial production of our first well on this acreage, the Kardell #1H. The well tested at 30.7 MMcfe/d, which we believe to be the highest publicly reported 24-hour initial production rate for a Haynesville Shale well in Texas or Louisiana to date and is currently flowing to sales. We believe the Kardell #1H confirms the potential of our Bruin Prospect, which is comprised of 3,000 net acres in San Augustine County, resulting in over 100 potential drilling locations in multiple formations. We are currently in the planning stages of several wells in this area and intend to further evaluate and exploit these multiple formations beginning in early 2010. We have an additional 9,000 net acres outside this prospect within Sabine and San Augustine Counties, and we expect to drill our initial well on that acreage in early 2010. We intend to allocate a substantial portion of our capital budget over the next several years to develop the significant potential that we believe exists on our East Texas acreage. Based on our current capital budget, we expect to drill approximately 7 gross (3.0 net) wells in 2010 that will target the Haynesville and Bossier Shales, while retaining future development opportunities in shallower formations.

Develop our South Texas resource play. We have approximately 2,800 net acres in Bee County, Texas which we believe is prospective in the Austin Chalk and Eagle Ford Shale. In November 2009, we drilled our initial well on this acreage, the Dubose #1. This well is in the process of being completed with results expected prior to year end 2009. We intend to allocate a portion of our capital budget in 2010 to validate the potential we believe exists on our acreage.

Exploit our existing producing property base to generate cash flows. We believe our multi-year drilling inventory of high return exploitation opportunities on our existing producing properties provides us with a solid platform to continue growing our reserves and production for the next several years. We believe these projects, if successful, will allow us to fund a larger portion of our resource plays and exploration activities from cash flows from operations. In 2010, we intend to focus much of our exploitation drilling on our Liberty County acreage, located in Southeast Texas. We will be targeting the Yegua and Cook Mountain formations in which industry players have recently experienced success on wells in the area. We own 3D seismic data that covers substantially all of our Liberty County acreage, giving us a higher degree of confidence in the potential in this area. We have drilled 11 gross (6.8 net) wells in Liberty County since early 2008 and have successfully completed 82%. During 2010, we intend to drill 4 gross (2.6 net) wells in this area.

Explore in defined producing trends. Our exploration activities consist primarily of step-out drilling in known, producing formations in our legacy areas of South and Southeast Texas. In 2007, we began acquiring seismic data to use in identifying new exploration prospects. Currently, we have a library of over 4,200 square miles of 3D seismic data and over 2,500 linear miles of 2D seismic data.

2

Make opportunistic acquisitions that meet our strategic and financial objectives. We seek to acquire natural gas and crude oil properties, including both undeveloped and producing reserves in areas where we have specific operating expertise.

Reduce commodity exposure through hedging. We employ the use of swaps and costless collar derivative instruments to limit our exposure to commodity prices. As of September 30, 2009, we had 13.9 Bcfe of equivalent production hedged, representing 1.8 Bcf, 6.1 Bcf and 3.2 Bcf of natural gas hedges in place and 86 MBbl, 250 MBbl and 124 MBbl of crude oil hedges in place for the fourth quarter of 2009, the year 2010 and the year 2011, respectively. The average price of our natural gas and crude oil hedges in place is $8.19/MMBtu and $86.03/Bbl for the fourth quarter of 2009, $7.71/MMBtu and $83.02/Bbl in the year 2010 and $7.32/MMBtu and $66.50/Bbl in the year 2011.

Our Competitive Strengths

Our competitive strengths include:

Geographically focused operations in basins with established production profiles. The geographic concentration of our current operations along the onshore Texas Gulf Coast and in South Texas allows us to establish economies of scale with respect to drilling, production, operating and administrative costs, and enables us to leverage our base of technical expertise in these geographic areas. In addition, we believe the cash flows from our existing properties provide a stable foundation to support our ongoing exploitation and development efforts.

Significant operational control. As of September 30, 2009, we operated a majority of our producing wells. As a result, we exercise a significant level of control over the amount and timing of expenses, capital allocation and other aspects of development, exploitation and exploration. While operatorship of future wells on our East Texas acreage will be subject to negotiation as drilling units are formed, we expect to operate a significant number of the wells we drill on this acreage.

Proven track record of reserve and production growth. Since 2005, we have significantly grown proved reserves and production through a combination of continued drilling success and the successful acquisition of underdeveloped properties that have proven to be complementary to our existing asset base and technical expertise. We plan to continue this growth by focusing on a balanced combination of drilling longer life, multi-pay natural gas targets within our resource plays and exploitation of our producing properties and undeveloped acreage.

Large inventory of identified projects. We currently have an inventory of over 800 identified potential drilling locations, including 375 associated with our existing conventional properties, plus an estimated 422 locations on our East Texas resource play acreage and an estimated 25 locations on our South Texas resource play acreage. Since the beginning of 2008, we have drilled 16 gross (10.7 net) operated and 18 gross (4.5 net) non-operated wells and have experienced a 91% success rate (excluding one well which has not yet been completed). We expect to drill 12 gross (6.0 net) wells in 2010.

Experienced management and technical teams. Our senior management team averages over 25 years of experience in the energy industry and is led by Allan D. Keel, President and Chief Executive Officer, who has 25 years of experience in the oil and natural gas industry. Mr. E. Joseph Grady, our Senior Vice President and Chief Financial Officer, has over 30 years of financial management experience in the energy industry. Other members of our senior management include: Mr. Tracy Price, our Senior Vice President Land Business/Development; Mr. Thomas H. Atkins, our Senior Vice President Exploration; and

Mr. Jay S. Mengle, our Senior Vice President Engineering, each of whom has more than 25 years of experience in the oil and gas industry. Our experienced management team has an established track record of successfully exploiting and developing natural gas and crude oil properties.

Our Operations

Our areas of primary focus include the following:

East Texas. Our East Texas properties include approximately 17,000 gross (12,000 net) acres acquired in 2008 and early 2009 in the highly prospective and active resource play in San Augustine and Sabine Counties, where we will focus primarily on the pursuit of the Haynesville Shale, Bossier Shale and James Lime formations. In October 2009, we drilled and completed our first well in this area, the Kardell #1H. While drilling this well, we identified additional prospective formations, including the Pettet and Knowles Lime.

Southeast Texas. Our Southeast Texas properties primarily include the Felicia field area in Liberty County. We own approximately 27,300 gross (15,100 net) acres in Liberty, Madison and Grimes Counties. As of September 30, 2009, we owned and operated 35 gross (27.0 net) producing wells, representing approximately 38% of our average daily production for the first nine months of 2009.

South Texas. Our South Texas properties include approximately 2,800 gross (2,800 net) acres in Bee County, which we believe to be prospective in the Austin Chalk and Eagle Ford Shale. Our conventional operations include approximately 87,600 gross (50,700 net) acres predominately in Brooks, Lavaca, DeWitt, Zapata, Webb and Matagorda Counties.

We also own interests in the following areas:

Colorado and Other. Our Colorado and other properties include primarily producing assets and approximately 16,900 gross (11,900 net) acres in the Denver Julesburg Basin in Colorado (mostly in Adams County) and a minor crude oil property in Mississippi.

Southwest Louisiana. Our Southwest Louisiana properties include approximately 8,200 gross (3,600 net) acres, primarily in the Fenton field area of Calcasieu Parish and our legacy Grand Lake and Lacassine fields in Cameron Parish. In addition, we own a 15% working interest ownership in 2007 exploratory successes in Louisiana at Sabine Lake and West Cameron 432. On November 24, 2009, we entered into a purchase and sale agreement for the sale of substantially all of our Southwest Louisiana properties. See Recent Developments Southwest Louisiana Disposition.

Table of Contents

The following table sets forth certain information with respect to our estimated proved reserves as of December 31, 2008, as estimated by Netherland, Sewell & Associates, Inc., and production for the nine months ended September 30, 2009. The following table also identifies potential drilling locations and net acreage as of September 30, 2009.

Region	Estimated Proved Reserves as of December 31, 2008 (MMcfe)	% Natural Gas	% Proved Developed	Average Daily Production For the Nine Months Ended September 30, 2009 (Mcfe/d)	Net Acreage at September 30, 2009	Identified Potential Gross Drilling Locations at September 30, 2009(1)
Southeast Texas	29,393	60.1%	85.8%	16,521	15,100	26
South Texas	60,602	78.0%	59.8%	11,963	53,500	124
Colorado and Other	6,675	71.5%	55.3%	539	11,900	164
East Texas(2)					12,000	422
Southwest Louisiana(3)	10,398	62.4%	57.3%	3,139	3,600	4
Non-operated(3)(4)	24,879	80.2%	79.8%	10,817		82
Total	131,947	72.9%	68.9%	42,979	96,100	822

(1) Includes multiple drilling locations on acreage with multiple target formations.

(2) We recently completed our first well on our East Texas acreage, the Kardell #1H, as a horizontal Haynesville Shale producer, in which we own a 52% working interest. Drilling locations in this region were identified assuming an allocated 100 acres per potential horizontal East Texas well drilled to multiple target formations.

(3) On November 24, 2009, we entered into a purchase and sale agreement for the sale of substantially all of our operated and certain non-operated Southwest Louisiana properties. See Recent Developments Southwest Louisiana Disposition.

(4) Our non-operated properties consist primarily of our 25% working interest in the Samano field in Starr and Hidalgo Counties in South Texas, our 28% working interest in certain fields in Liberty County in Southeast Texas and our 15% and 15% respective working interests resulting from exploratory successes in 2007 at Sabine Lake and West Cameron 432 in Southwest Louisiana.

Recent Developments

Amendments to Revolving Credit Facility. Effective December 7, 2009, we entered into a fourth amendment to our revolving credit facility. This amendment provides, among other things, that, subject to the closing of this offering, (i) the ratio of our total debt to Adjusted EBITDAX for any four trailing fiscal quarters may not be greater than 3.50x as of the end of any fiscal quarter ending on or prior to December 31, 2010, and 3.25x as of the end of any fiscal quarter ending thereafter, and (ii) the ratio of Adjusted EBITDAX to cash interest expense for any four trailing fiscal quarters may not be less than 2.25x as of the end of any fiscal quarter ending on or prior to December 31, 2010, and 2.75x as of the end of any fiscal quarter ending thereafter. In addition, this amendment also provides that, subject to the closing of this offering, the borrowing base under our revolving credit facility will be redetermined to be $105.0 million at January 1, 2010 and that we may issue up to $200 million in senior unsecured notes. Any such issuance of senior unsecured notes will reduce our borrowing base by 25% of the net proceeds from such issuance in excess of $150 million.

Southwest Louisiana Disposition. On November 24, 2009, we entered into a definitive agreement to sell operated and non-operated working interests in various producing wells, related production equipment and associated acreage primarily in Cameron, Calcasieu and Jefferson Davis parishes in Southwest Louisiana for an aggregate contract price of $10.2 million, subject to normal purchase price adjustments for environmental defects and oil and gas operations for the period between the effective date and the final closing date, and the assumption of all related asset retirement obligations, with an effective date of October 1, 2009. The assets include substantially all of our Southwest Louisiana properties, representing approximately 10.7 Bcfe of proved reserves at December 31, 2008, with average daily production of approximately 3.8 MMcfe/d for the nine months ended September 30, 2009, or approximately 9% of our total daily production for such period. We expect to use the proceeds from this sale to repay outstanding amounts under our revolving credit facility. We anticipate closing the transaction prior to 2010, subject to the prior satisfaction of customary closing conditions. We cannot assure you that all of the conditions to closing will be timely satisfied or satisfied at all. The disposition of our Southwest Louisiana properties has been contemplated in the redetermination of our borrowing base at January 1, 2010 in connection with the amendments to our revolving credit facility.

Preferred Stock Conversion

As of September 30, 2009, there were 80,500 shares of our Series G convertible preferred stock, par value $0.01 per share (Series G Preferred Stock), outstanding. OCM GW Holdings, LLC (Oaktree Holdings) and OCM Crimson Holdings, LLC (OCM Crimson), affiliates of Oaktree Capital Management, LP (Oaktree Capital Management), currently hold 76,700 and 10 shares, respectively, of our Series G Preferred Stock and Allan D. Keel, our President and CEO, currently holds 600 shares of our Series G Preferred Stock. With the recommendation of an independent committee of our Board of Directors and the consent of OCM Holdings and OCM Crimson, holders in the aggregate of approximately 95% of our outstanding Series G Preferred Stock, on December 8, 2009, we amended the terms of such preferred stock to provide for the conversion of all outstanding shares of Series G Preferred Stock in connection with this offering. See Certain Relationships and Related Party Transactions. We anticipate issuing 8,418,206 shares of our common stock in connection with the conversion of all of our Series G Preferred Stock and the accrued but unpaid dividends on those shares, assuming an offering price of $7.00 per share, which is the midpoint in the range provided on the cover page of this prospectus. Of those shares of common stock, we anticipate issuing an aggregate of 8,021,870 shares to Oaktree Holdings and OCM Crimson and 62,744 shares to Mr. Keel.

As of September 30, 2009, there were 2,100 shares of our Series H convertible preferred stock, par value $0.01 per share (our Series H Preferred Stock), outstanding, which shares were held of record by three stockholders, including 2,000 shares held by Oaktree Holdings. Each share of our Series H Preferred Stock is convertible into the number of shares of our common stock that is equal to $500 divided by $3.50. Pursuant to the Certificate of Designations governing the terms of the Series H Preferred Stock, if Oaktree Holdings or its affiliates convert all of their shares of Series G Preferred Stock into common stock, all shares of Series H Preferred Stock automatically convert into shares of our common stock. We anticipate issuing 300,000 shares of our common stock in connection with the conversion of all of our Series H Preferred Stock.

Upon the completion of this offering, Oaktree Holdings and OCM Crimson will together own approximately 31% of our outstanding common stock and Mr. Keel will hold approximately 4% of our outstanding common stock, assuming the exercise of all vested and unvested stock options held by him (in each case, estimated based upon the midpoint of the range of the offering price on the cover of this prospectus). Please see Summary Consolidated Financial Data Pro Forma Net Income (Loss) Per Share Data for information with respect to the effect of the conversion of the Series G Preferred Stock and the Series H Preferred Stock (the Preferred Stock Conversion) on our net income (loss) per share.

Principal Stockholder

Our principal stockholder is Oaktree Holdings, an affiliate of Oaktree Capital Management. Oaktree Capital Management is a premier global alternative and non-traditional investment manager

with over $67 billion in assets under management as of September 30, 2009. The firm emphasizes an opportunistic, value-oriented and risk-controlled approach to investments in distressed debt, high yield and convertible bonds, specialized private equity (including power infrastructure), real estate, emerging market and Japanese securities, and mezzanine finance. Oaktree Capital Management was founded in 1995 by a group of principals who have worked together since the mid-1980s. Headquartered in Los Angeles, the firm today has over 580 employees in 14 offices worldwide.

Risk Factors

Investing in our common stock involves substantial risk. For a discussion of certain risks you should consider in making an investment, see Risk Factors beginning on page 16. In particular, the following considerations may offset our business strengths or have a negative effect on 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:

- Natural gas, crude oil and natural gas liquids prices are volatile, and a decline in prices can significantly affect our financial results and impede our growth.
- Initial production rates in shale plays, and particularly in the Haynesville Shale, tend to decline steeply in the first twelve months of production and are not necessarily indicative of sustained production rates.
- Our development and exploration operations, including on our East Texas resource play acreage, require substantial capital, and we may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a loss of properties and a decline in our natural gas, crude oil and natural gas liquids reserves.
- Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions could materially reduce the estimated quantities and present value of our reserves.
- We have incurred net losses in the past and there can be no assurance that we will be profitable in the future.
- Unless we replace our natural gas and crude oil reserves, our reserves and production will decline, which would adversely affect our cash flows, our ability to raise capital and the value of our common stock.
- We have a substantial amount of indebtedness, which may adversely affect our cash flow and our ability to operate our business.

Corporate Structure

Our company was founded in 1987 and is incorporated in Delaware. In February 2005, the Company, previously incorporated in Texas and named GulfWest Energy Inc., was recapitalized and in June 2005 was reincorporated as a Delaware corporation, and renamed Crimson Exploration Inc. We are organized as a holding company with most of our oil and gas assets held in our primary operating subsidiary.

Our Offices

Our principal office is located at 717 Texas Avenue, Suite 2900, Houston, Texas 77002 and our telephone number is (713) 236-7400.

Table of Contents

The Offering

Issuer	Crimson Exploration Inc.
Common stock offered by us	18,000,000 shares
Underwriters option to purchase additional shares	We have granted the underwriters a 30-day option to purchase up to an additional 2,700,000 shares of common stock.
Common stock outstanding immediately following this offering	33,134,607 shares of common stock (excluding 2,700,000 shares that will be sold to the underwriters if they exercise their option to purchase additional shares), including 8,718,206 shares that will be issued pursuant to the Preferred Stock Conversion, assuming an offering price of $7.00, which is the midpoint of the range provided on the cover page of this prospectus
Use of proceeds	We estimate that our net proceeds from this offering will be approximately $117.6 million after deducting underwriting discounts and commissions and estimated offering expenses, assuming an offering price of $7.00, which is the midpoint of the range provided on the cover page of this prospectus. We intend to use the net proceeds from this offering to repay approximately $107.6 million in aggregate principal amount of indebtedness outstanding under our revolving credit facility and to repay our $10 million unsecured promissory note in full. Affiliates of certain of the underwriters are lenders under our existing revolving credit facility and therefore will receive a portion of the net proceeds of this offering. See Underwriting.
Dividend policy	We have not declared or paid any cash dividends on our common stock or preferred stock, and we do not currently anticipate paying any cash dividends on our common stock or preferred stock in the foreseeable future. For more information, see Dividend Policy.
NASDAQ symbol	CXPO
Risk factors	An investment in our common stock involves a high degree of risk. See Risk Factors and other information included elsewhere in this prospectus for a discussion of factors you should consider before investing in our common stock.

Unless we specifically state otherwise, the information in this prospectus (i) gives effect to the Preferred Stock Conversion as if it will occur in December of 2009; (ii) assumes no exercise by the underwriters of their option to purchase 2,700,000 additional shares of common stock; (iii) excludes an aggregate of 551,315 shares of common stock reserved and available for future issuance under our 2005 Stock Incentive Plan and 1,960,310 shares issuable upon exercise of outstanding options at a weighted average exercise price of $8.82 per share as of December 4, 2009; and (iv) is based on 6,416,401 shares outstanding (including approximately 0.6 million shares of restricted common stock to be issued to our employees, including to our executive officers, pursuant to our performance-based long-term incentive compensation plan) as of December 4, 2009.

Table of Contents

Summary Consolidated Financial Data

The following table presents summary historical consolidated financial data of our business, as of the dates and for the periods indicated. The summary historical consolidated financial data as of and for the year ended December 31, 2008 have been derived from our audited consolidated financial statements and related notes included elsewhere in this prospectus. The summary historical consolidated financial data for the nine months ended September 30, 2008 and 2009 have been derived from our unaudited consolidated financial statements included elsewhere in this prospectus. The September 30, 2008 and 2009 financial statements have been prepared on a basis consistent with our audited consolidated financial statements and reflect all adjustments, consisting of normal recurring adjustments, which are, in the opinion of management, necessary for a fair presentation of the financial position and results of operations for the periods presented.

The summary consolidated financial data should be read in conjunction with Selected Historical Consolidated Financial Data, Management s Discussion and Analysis of Financial Condition and Results of Operations, Risk Factors and our consolidated financial statements and related notes included elsewhere in this prospectus.

	Year Ended December 31,			Nine Months Ended September 30,	
	2006	2007	2008	2008	2009
			(In thousands)		
				(unaudited)	
Statement of Operations Data:					
Operating revenues:					
Natural gas sales	$ 10,570	$ 67,868	$ 116,415	$ 92,075	$ 55,135
Crude oil sales	10,908	27,021	41,860	34,150	21,519
Natural gas liquids sales		14,273	27,405	24,687	9,089
Operating overhead and other income	181	381	1,088	889	508
Total operating revenues	21,659	109,543	186,768	151,801	86,251
Operating expenses:					
Lease operating expenses	5,633	12,034	20,825	15,363	13,518
Production and ad valorem taxes	1,895	11,702	16,266	14,355	6,061
Exploration expenses	673	3,174	9,965	1,877	2,873
Depreciation, depletion and amortization	4,035	30,796	50,467	36,030	41,599
Impaired assets of oil and gas properties(1)	3,150	4,362	35,954	25,799	
General and administrative	8,730	14,542	22,406	17,819	13,381
(Gain) loss on sale of assets(2)	2	(683)	(15,210)	(15,272)	19
Total operating expenses	24,118	75,927	140,673	95,971	77,451
Income (loss) from operations(3)	(2,459)	33,616	46,095	55,830	8,800
Other income (expense):					
Interest expense, net of amount capitalized	(109)	(14,949)	(21,109)	(15,871)	(16,349)
Other financing costs	(228)	(1,322)	(1,501)	(1,174)	(1,110)
Loss from equity in investments	(2)				

Unrealized gain (loss) on derivative instruments	6,082	(18,186)	49,409	1,665	(17,238)
Total other income (expense)	5,743	(34,457)	26,799	(15,380)	(34,697)
Income (loss) before income taxes	3,284	(841)	72,894	40,450	(25,897)
Income tax benefit (expense)	(1,425)	410	(26,691)	(15,105)	9,080
Net income (loss)	1,859	(431)	46,203	25,345	(16,817)
Preferred stock dividends	(3,649)	(4,453)	(4,234)	(3,164)	(3,353)
Net income (loss) available to common stockholders	$ (1,790)	$ (4,884)	$ 41,969	$ 22,181	$ (20,170)

Table of Contents

	Year Ended December 31,			Nine Months Ended September 30,	
	2006	2007	2008	2008	2009
	(In thousands, except per share data)				
				(unaudited)	
Net Income (Loss) Per Share Information					
Basic					
Weighted average shares outstanding	3,231	4,330	5,371	5,225	6,301
Net income (loss) per share	$ (0.55)	$ (1.13)	$ 7.81	$ 4.25	$ (3.20)
Diluted					
Weighted average shares outstanding	3,231	4,330	10,360	10,289	6,301
Net income (loss) per share	$ (0.55)	$ (1.13)	$ 4.46	$ 2.46	$ (3.20)
Other Financial Data					
Adjusted EBITDAX[(4)]	$ 9,219	$ 76,003	$ 132,707	$ 108,715	$ 55,160
Capital expenditures[(5)]					
Acquisitions of oil and gas properties	$	$ 253,434	$ 58,482	$ 58,032	$ (494)
Other capital expenditures[(6)]	21,777	59,049	141,795	82,577	16,545
Total	$ 21,777	$ 312,483	$ 200,277	$ 140,609	$ 16,051

	As of September 30, 2009	Pro Forma As Adjusted as of September 30, 2009[(7)]
Balance Sheet Data (end of period):		
Property and equipment, net	$ 425,236	$ 425,236
Total assets	462,481	464,481
Long-term debt, including current portion	291,526	175,941
Stockholders equity	106,542	224,127
Total liabilities and stockholders equity	462,481	464,481

(1) For the year ended December 31, 2008, includes (i) an impairment expense of $10.2 million in December 2008 with respect to our Grand Lake Field in Southwest Louisiana, resulting from negative reserve revisions resulting from year end low commodity prices, and (ii) $25.8 million in asset impairments in the nine months ended September 30, 2008 resulting from our capital investment in the Rodessa formation within the Madisonville Field.

(2) For the year ended December 31, 2008 and the nine months ended September 30, 2008, includes a gain of $15.6 million resulting from the disposition of our interest in the Barnett Shale Play in January 2008.

(3) Non-cash equity-based compensation charges were $5.4 million, $4.7 million and $3.8 million, in 2008, 2007 and 2006, respectively. Non-cash equity-based compensation charges were $1.9 million and $4.5 million for the nine months ended September 30, 2009 and 2008, respectively.

(4) Adjusted EBITDAX is a non-GAAP financial measure. Our definition of Adjusted EBITDAX and a reconciliation of net income (loss) to Adjusted EBITDAX is provided under Non-GAAP Financial Measures and Reconciliations.

(5) Capital expenditures are derived from our consolidated statements of cash flows in our financial statements included elsewhere in this prospectus.

(6) Other capital expenditures consists primarily of capital drilling and lease acquisitions.

(7) On an adjusted pro forma basis to give effect to this offering (estimated based upon the midpoint of the range of the offering price on the cover of this prospectus), the application of the estimated net proceeds of this offering, the Preferred Stock Conversion, the issuance of $12 million in unsecured promissory notes and the repayment of loans under our revolving credit facility with proceeds of one of such promissory notes.

Table of Contents

Pro Forma Net Income (Loss) Per Share Data

The pro forma data presented in the following table gives effect to the Preferred Stock Conversion as of the beginning of the period presented (estimated based upon the midpoint of the range of the offering price on the cover of this prospectus).

	Year Ended December 31, 2008	Nine Months Ended September 30, 2009
	(In thousands, except per share data)	
Pro forma preferred stock dividends	$	$
Pro forma net income (loss) available to common stockholders	46,203	(16,817)
Pro forma basic net income (loss) per share:		
Weighted average shares outstanding	13,263	14,449
Net income (loss) per share	$ 3.48	$ (1.16)
Pro forma diluted net income (loss) per share:		
Weighted average shares outstanding	13,468	14,449
Net income (loss) per share	$ 3.43	$ (1.16)

Table of Contents

Summary Reserve and Historical Operating Data

The following tables present certain information with respect to our estimated proved natural gas, crude oil and natural gas liquids reserves at year end and operating data for the periods presented. The table shows estimated net proved reserves and related data, based on the reserve report at December 31, 2006, 2007 and 2008, substantially all of which were prepared by our independent petroleum engineers. The table also shows proved reserves and related data at September 30, 2009 based upon a reserve report prepared by our independent petroleum engineers. Our September 30, 2009 proved reserves and related PV-10 were significantly affected by reduced commodity prices and reduced capital expenditures for drilling during 2009. You should refer to Risk Factors, Management s Discussion and Analysis of Financial Condition and Results of Operations, Business Proved Reserves and Business Production, Revenue and Price History when evaluating the material presented below.

	Year Ended December 31,			Nine Months Ended September 30,	
	2006	2007	2008	2008	2009
Production:					
Natural gas (MMcf)	1,542	9,068	13,136	9,753	8,143
Crude oil (MBbl)	185	409	498	385	264
Natural gas liquids (MBbl)		286	516	422	334
Total (MMcfe)	2,652	13,236	19,222	14,598	11,733
Average Sales Prices (Before Hedging):					
Natural gas (Mcf)	$ 6.76	$ 6.78	$ 8.92	$ 9.83	$ 3.92
Crude oil (Bbl)	$ 63.29	$ 74.38	$ 101.13	$ 112.98	$ 52.80
Natural gas liquids (Bbl)		$ 49.92	$ 53.07	$ 58.49	$ 27.19
Natural gas equivalents (Mcfe)	$ 8.34	$ 8.02	$ 10.14	$ 11.24	$ 4.68
Average Sales Prices (After Hedging)(1):					
Natural gas (Mcf)	$ 6.85	$ 7.48	$ 8.86	$ 9.44	$ 6.77
Crude oil (Bbl)	$ 59.00	$ 66.09	$ 84.03	$ 88.60	$ 81.46
Natural gas liquids (Bbl)		$ 49.92	$ 53.07	$ 58.49	$ 27.19
Natural gas equivalents (Mcfe)	$ 8.10	$ 8.25	$ 9.66	$ 10.34	$ 7.31
Expenses: (Mcfe)					
Lease operating expenses	$ 2.12	$ 0.91	$ 1.08	$ 1.05	$ 1.15
Production and ad valorem taxes	$ 0.71	$ 0.88	$ 0.85	$ 0.98	$ 0.52
Exploration expenses	$ 0.25	$ 0.24	$ 0.52	$ 0.13	$ 0.24
General and administrative	$ 3.29	$ 1.10	$ 1.17	$ 1.22	$ 1.14
Depreciation, depletion and amortization	$ 1.52	$ 2.33	$ 2.63	$ 2.47	$ 3.55
Proved Reserves (end of period)(2)(3):					
Natural gas (MMcf)	31,388	91,239	96,169		73,768
Crude oil (MBbl)	2,501	2,903	2,564		2,358
Natural gas liquids (MBbl)		3,590	3,399		2,823
Total proved reserves (MMcfe)	46,394	130,197	131,947		104,854
Percent proved developed reserves	88%	75%	69%		68%
PV-10 (in millions)(4)	$ 102.4	$ 531.4	$ 291.0		$ 190.8
Standardized measure (in millions)(5)	77.4	399.5	260.9		N.A.
Prices utilized in estimates(6):					
Natural gas (MMBtu)	$ 6.03	$ 6.80	$ 5.71		$ 3.30
Crude oil (Bbl)	$ 61.06	$ 92.50	$ 41.00		$ 67.00

12

(1) Amounts shown are based on natural gas and crude oil sales, net of realized commodity derivative gains (losses).

(2) Does not give effect to the disposition of substantially all of our Southwest Louisiana properties, representing approximately 8.5 Bcfe of proved reserves at September 30, 2009, approximately $19.9 million of PV-10 as of September 30, 2009, and with an average daily production of approximately 3.8 MMcfe/d for the nine months ended September 30, 2009, or approximately 9% of our total daily production for such period. See Recent Developments Southwest Louisiana Disposition.

(3) Our independent petroleum engineers did not prepare a reserve report for proved reserves and related data at September 30, 2008.

(4) PV-10 is a non-GAAP financial measure. A reconciliation of our Standardized Measure of Discounted Net Cash Flows to PV-10 is provided under Non-GAAP Financial Measures and Reconciliations.

(5) The Standardized Measure of Discounted Net Cash Flows represents the present value of estimated future cash inflows from proved natural gas and crude oil reserves, less future development and production costs, and income tax expenses, discounted at 10% per annum to reflect timing of future cash flows and using the same pricing assumptions as were used to calculate PV-10. Standardized Measure differs from PV-10 because Standardized Measure includes the effect of future income taxes.

(6) Natural gas prices are based on Henry Hub spot prices at year end, except for 2006 which is based on NYMEX prices. Oil prices are based upon year end West Texas Intermediate posted prices. Under new SEC rules, prices used in determining our proved reserves as of December 31, 2009 will be based upon an unweighted 12-month first day of the month average price of $3.87 per MMBtu (Henry Hub spot) of natural gas and $57.65 per barrel of oil (West Texas Intermediate posted). These are adjusted for quality, energy content, transportation fees and regional price differentials.

Non-GAAP Financial Measures and Reconciliations

Adjusted EBITDAX

EBITDAX represents net income (loss) before net interest expense, taxes, and depreciation, amortization and exploration expenses. Adjusted EBITDAX represents EBITDAX as further adjusted to reflect the items included in the table below, all of which will be required in determining our compliance with financial covenants under our revolving credit facility and second lien term loan agreement.

We have included EBITDAX and Adjusted EBITDAX in this prospectus to provide investors with a supplemental measure of our operating performance and information about the calculation of some of the financial covenants that are contained in our credit agreements. We believe EBITDAX is an important supplemental measure of operating performance because it eliminates items that have less bearing on our operating performance and so highlights trends in our core business that may not otherwise be apparent when relying solely on generally accepted accounting principles, or GAAP, financial measures. We also believe that securities analysts, investors and other interested parties frequently use EBITDAX in the evaluation of issuers, many of which present EBITDAX when reporting their results. Adjusted EBITDAX is a material component of the covenants that are imposed on us by our revolving credit facility and second lien term loan agreement. We are subject to financial covenant ratios that are or will be calculated by reference to Adjusted EBITDAX. Non-compliance with the financial covenants contained in these credit agreements could result in a default, an acceleration in the repayment of amounts outstanding, and a termination of lending commitments. For a description of required financial covenant levels and actual ratio calculations based on Adjusted

EBITDAX, see Management s Discussion and Analysis of Financial Condition and Results of Operations Financial Condition Liquidity and Capital Resources Covenant compliance. Our management and external users of our financial statements, such as investors, commercial banks, research analysts and others, also use EBITDAX and Adjusted EBITDAX to assess:

- the financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- the ability of our assets to generate cash sufficient to pay interest costs and support our indebtedness;
- our operating performance and return on capital as compared to those of other companies in our industry, without regard to financing or capital structure; and
- the feasibility of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

EBITDAX and Adjusted EBITDAX are not presentations made in accordance with GAAP. As discussed above, we believe that the presentation of EBITDAX and Adjusted EBITDAX in this prospectus is appropriate. However, when evaluating our results, you should not consider EBITDAX and Adjusted EBITDAX in isolation of, or as a substitute for, measures of our financial performance as determined in accordance with GAAP, such as net income (loss). EBITDAX and Adjusted EBITDAX have material limitations as performance measures because they exclude items that are necessary elements of our costs and operations. Because other companies may calculate EBITDAX and Adjusted EBITDAX differently than we do, EBITDAX may not be, and Adjusted EBITDAX as presented in this prospectus is not, comparable to similarly-titled measures reported by other companies.

The following table reconciles net income (loss) to EBITDAX and Adjusted EBITDAX for the periods presented:

	Year Ended December 31,					Nine Months Ended September 30,	
	2004	**2005**	**2006**	**2007**	**2008**	**2008**	**2009**
	(In thousands)						
Net income (loss)	$ 8,072	$ (3,543)	$ 1,859	$ (431)	$ 46,203	$ 25,345	$ (16,817)
Interest expense	4,154	1,302	109	14,949	21,109	15,871	16,349
Income tax expense (benefit)	(3,204)	(792)	1,425	(410)	26,691	15,105	(9,080)
Depreciation and amortization	2,257	3,209	4,035	30,796	50,467	36,030	41,599
Exploration expenses	433	750	673	3,174	9,965	1,877	2,873
EBITDAX	$ 11,712	$ 926	$ 8,101	$ 48,078	$ 154,435	$ 94,228	$ 34,924
Unrealized (gain) loss on derivative instruments	1,506	1,642	(6,082)	18,186	(49,409)	(1,665)	17,238
Non-cash equity-based compensation charges		44	3,820	4,738	5,436	4,451	1,869
Impaired assets	61	3,689	3,150	4,362	35,954	25,799	
Other financing[(1)]	1,472	1,956	228	1,322	1,501	1,174	1,110
Forgiveness of debt	(12,476)						
	2,034	39	2	(683)	(15,210)	(15,272)	19

(Gain) loss on the disposition of assets							
Adjusted EBITDAX	$ 4,309	$ 8,296	$ 9,219	$ 76,003	$ 132,707	$ 108,715	$ 55,160

(1) Includes amortization of deferred finance costs and other fees and expenses payable under our credit agreements.

Table of Contents

PV-10

PV-10 is a non-GAAP financial measure and represents the year-end present value of estimated future cash inflows from proved natural gas and crude oil reserves, less future development and production costs, discounted at 10% per annum to reflect timing of future cash flows and using pricing assumptions in effect at the end of the period. PV-10 differs from Standardized Measure of Discounted Net Cash Flows because it does not include the effects of income taxes or non-property related expenses such as general and administrative expenses and debt service or depreciation, depletion and amortization on future net revenues. Neither PV-10 nor Standardized Measure represents an estimate of fair market value of our natural gas and crude oil properties. PV-10 is used by the industry and by our management as an arbitrary reserve asset value measure to compare against past reserve bases and the reserve bases of other business entities that are not dependent on the taxpaying status of the entity. GAAP does not require calculation of Standardized Measure for interim financial statements, and therefore there is no comparable GAAP financial measure to PV-10 for September 30, 2009.

The following table provides a reconciliation of our Standardized Measure to PV-10:

	At December 31,		
	2006	**2007**	**2008**
		(In millions)	
Standardized measure of discounted net cash flows	$ 77.4	$ 399.5	$ 260.9
Present value of future income tax and other discounted at 10%	25.0	131.9	30.1
PV-10	$ 102.4	$ 531.4	$ 291.0

Table of Contents

RISK FACTORS

Investing in our common stock involves a high degree of risk. You should carefully consider the risk factors included below as well as the other information contained in this prospectus before investing in our common stock, or deciding whether you will or will not participate in this offering. Any of the following risks could materially and adversely affect our business, financial condition or results of operations. In such a case, you may lose all or part of your investment.

Risks Related to Our Business

Natural gas, crude oil and natural gas liquids prices are volatile, and a decline in prices can significantly affect our financial results and impede our growth.

Our revenue, cash flow from operations and future growth depend upon the prices and demand for natural gas, crude oil and natural gas liquids. The markets for these commodities are very volatile. Even relatively modest drops in prices can significantly affect our financial results and impede our growth. Changes in natural gas, crude oil and natural gas liquids prices have a significant impact on the value of our reserves and on our cash flow. In addition, periods of sustained lower prices may compel us to reduce our capital expenditures and budget for drilling. Prices for natural gas, crude oil and natural gas liquids may fluctuate widely in response to relatively minor changes in the supply of and demand for natural gas, crude oil and natural gas liquids and a variety of additional factors that are beyond our control, such as:

- the domestic and foreign supply of natural gas, crude oil and natural gas liquids;
- the price of foreign imports;
- worldwide economic conditions;
- political and economic conditions in oil producing countries, including the Middle East and South America;
- the ability of members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- the level of consumer product demand;
- weather conditions;
- technological advances affecting energy consumption;
- availability of pipeline infrastructure, treating, transportation and refining capacity;
- domestic and foreign governmental regulations and taxes; and
- the price and availability of alternative fuels.

Lower natural gas and crude oil prices may not only decrease our revenues on a per share basis, but also may reduce the amount of natural gas and crude oil that we can produce economically. This may result in our having to make substantial downward adjustments to our estimated proved reserves.

Our East Texas leases must be drilled before expiration, generally within three years, in order to hold the leases by production. In the highly competitive market for Haynesville Shale acreage, failure to drill sufficient wells timely to hold this acreage will result in a substantial renewal cost, or if renewal is not feasible, loss of lease investment and prospective drilling opportunities in the Haynesville Shale, Bossier Shale and James Lime formations.

Our East Texas leases have three year terms which require that an initial producing well be drilled prior to expiration date or the lease will terminate. Most of our leases in this area were signed in

Table of Contents

late 2008. Generally, once an initial well is drilled and completed as a producer, the lease is extended for the duration of production subject to payment of royalties and additional wells may be drilled on that lease. The leases in this area are extremely fragmented and much of the leased acreage is not contiguous. In many cases, contiguous leases owned by us are not large enough to accommodate horizontal drilling to the Haynesville Shale, which usually involves a horizontal lateral of between 4,000 to 5,000 feet within lease lines. In other cases, leases may be from fractional interest land owners and may not comprise a sufficient aggregate percentage working interest to make such a well economic. As a result, in order to realize the drilling opportunities in the Haynesville Shale, Bossier Shale and James Lime formations, we and other similarly situated major lease owners and operators in East Texas will need to cooperate and negotiate joint drilling operations in order to drill initial wells prior to lease expirations. These negotiations may include the right to act as operator for jointly owned wells. If we do not reach agreements with other major lease owners and operators to drill wells prior to lease expirations, or if we are unable to drill timely sufficient wells to hold our acreage, we will lose the drilling opportunities and investment in the expiring leases unless we can successfully negotiate to renew the leases. We may not be able to renew the expired leases, or if renewed, the cost of releasing could be substantial, particularly if development in this area proves successful.

Part of our strategy involves exploratory drilling, including drilling in new or emerging plays. As a result, our drilling results in these areas are uncertain.

The results of our exploratory drilling in new or emerging plays, such as in our East Texas resource play, are more uncertain than drilling results in areas that are developed and have established production. Since new or emerging plays and new formations have limited or no production history, we are less able to use past drilling results in those areas to help predict our future drilling results. Accordingly, our drilling results are subject to greater risks in these areas and could be unsuccessful. To the extent we are unable to execute our expected drilling program in these areas, because of disappointing drilling results, capital constraints, lease expirations, access to adequate gathering systems or pipeline take-away capacity, availability of drilling rigs and other services, or otherwise, and/or natural gas and crude oil prices decline, we may not realize a return on our investment in these areas or the return on investment may not be as attractive as we anticipate and our common stock price may decrease. We could incur material write-downs of unevaluated properties, and the value of our undeveloped acreage could decline in the future if our drilling results are unsuccessful.

The results of our planned exploratory drilling in our East Texas and South Texas resource plays, which are newly emerging plays with limited drilling and production history, are subject to more uncertainties than our drilling program in our more established areas of operation in the onshore South Texas and U.S. Gulf Coast regions and may not meet our expectations for reserves or production.

We have recently completed drilling our first well in the Haynesville Shale in East Texas, for which we were not operator, as well as a test well in Bee County, South Texas to the Eagle Ford Shale. The exploration of the Haynesville Shale in the East Texas area where we own leases has been limited. Part of our drilling strategy to maximize recoveries from the Haynesville Shale involves the drilling of horizontal wells using completion techniques that have proven to be successful in other shale formations. Our experience with horizontal drilling of these shale plays is limited. The ultimate success of these drilling and completion strategies and techniques in these formations will be better evaluated over time as more wells are drilled and production profiles are better established. Accordingly, the results of our future drilling in the emerging shale plays are more uncertain than drilling results in our more established areas of operation with established reserves and production history.

Table of Contents

Initial production rates in shale plays, and particularly in the Haynesville Shale, tend to decline steeply in the first twelve months of production and are not necessarily indicative of sustained production rates.

The initial production rate for our first well in our Haynesville acreage was 30.7 MMcfe/d, which we believe to be the highest publicly reported 24-hour initial production rate for a Haynesville Shale well in Texas or Louisiana. However, initial production rates in shale plays, and particularly in the Haynesville Shale, tend to decline steeply in the first twelve months of production and are not necessarily indicative of sustained production rates.

Our development and exploration operations, including on our East Texas resource play acreage, require substantial capital, and we may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a loss of properties and a decline in our natural gas, crude oil and natural gas liquids reserves.

The oil and gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures in our business and operations for the exploration, development, production and acquisition of natural gas, crude oil and natural gas liquids reserves. We intend to finance our future capital expenditures primarily with cash flow from operations and borrowings under our revolving credit facility. Our cash flow from operations and access to capital is subject to a number of variables, including:

- our proved reserves;
- the level of natural gas and crude oil we are able to produce from existing wells;
- the prices at which natural gas and crude oil are sold; and
- our ability to acquire, locate and produce new reserves.

If our revenues decrease as a result of lower natural gas, crude oil and natural gas liquids 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 or to further develop and exploit our current properties, or for exploratory activity. In order to fund our capital expenditures, we may need to seek additional financing. Our credit agreements contain covenants restricting our ability to incur additional indebtedness without the consent of the lenders. Our lenders may withhold this consent in their sole discretion. In addition, if our borrowing base is redetermined resulting in a lower borrowing base under our revolving credit facility, we may be unable to obtain financing otherwise available under our revolving credit facility. See Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Capital resources.

Furthermore, we may not be able to obtain debt or equity financing on terms favorable to us, or at all. In particular, the cost of raising money in the debt and equity capital markets has increased substantially while the availability of funds from those markets generally has diminished significantly. Also, as a result of concerns about the stability of financial markets generally and the solvency of counterparties specifically, the cost of obtaining money from the credit markets generally has increased as many lenders and institutional investors have increased interest rates, enacted tighter lending standards, refused to refinance existing debt at maturity on terms that are similar to existing debt, and reduced, or in some cases ceased, to provide funding to borrowers. The failure to obtain additional financing could result in a curtailment of our operations relating to exploration and development of our prospects, which in turn could lead to a possible loss of properties and a decline in our natural gas, crude oil and natural gas liquids reserves.

Recent changes in the financial and credit markets may impact economic growth and natural gas, crude oil and natural gas liquids prices may continue to be adversely affected by general economic conditions.

Based on a number of economic indicators, global economic activity has slowed substantially. At the present time, the rate at which the global economy will slow has become increasingly uncertain. A continued slowing of global economic growth, and, in particular, economic growth in the United States, will likely continue to reduce demand for natural gas, crude oil and natural gas liquids, which in turn could likely result in lower prices for natural gas, crude oil and natural gas liquids. Natural gas and crude oil prices dropped dramatically from record levels of approximately $13 per MMbtu and $145 per barrel, respectively, in July 2008 to below $3 per MMbtu in September 2009 and below $34 per barrel in December 2008. A reduction in demand for, and the resulting lower prices of, natural gas, crude oil and natural gas liquids could adversely affect our results of operations.

Recent market events and conditions, including disruptions in the U.S. and international credit markets and other financial systems and the deterioration of the U.S. and global economic conditions, could, among other things, impede access to capital or increase the cost of capital, which would have an adverse effect on our ability to fund our working capital and other capital requirements.

Recent market events and conditions, including unprecedented disruptions in the current credit and financial markets and the deterioration of economic conditions in the U.S. and internationally have had a significant material adverse impact on a number of financial institutions and have limited access to capital and credit for many companies. These disruptions could, among other things, make it more difficult for us to obtain, or increase our cost of obtaining, capital and financing for our operations. Access to additional capital may not be available on terms acceptable to us or at all. Difficulties in obtaining capital and financing or increased costs for obtaining capital and financing for our operations would have an adverse effect on our ability to fund our working capital and other capital requirements.

We have incurred net losses in the past and there can be no assurance that we will be profitable in the future.

We have incurred net losses in two of the last five fiscal years. We cannot assure you that our current level of operating results will continue or improve. Our activities could require additional debt or equity financing. Our future operating results may fluctuate significantly depending upon a number of factors, including industry conditions, prices of natural gas, crude oil and natural gas liquids, rates of production, timing of capital expenditures and drilling success. Negative changes in these variables could have a material adverse effect on our business, financial condition, results of operations and the market value of our common stock.

Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions could materially reduce the estimated quantities and present value of our reserves.

The process of estimating natural gas and crude oil reserves is complex. It requires interpretations of available technical data and many estimates, including estimates based upon assumptions relating to economic factors. Any significant inaccuracies in these interpretations or estimates could materially reduce the estimated quantities and present value of reserves shown in this prospectus. See Business for information about our crude oil and natural gas reserves.

In order to prepare our estimates, we must project production rates and timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary. The process also requires economic assumptions about matters such as crude oil and natural gas prices, drilling and operating expenses, the amount and timing of capital expenditures, taxes and the availability of funds.

19

Actual future production, crude oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable natural gas and crude oil reserves most likely will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of reserves shown in this prospectus. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing natural gas and crude oil prices and other factors, many of which are beyond our control.

Approximately 31% of our total estimated proved reserves at December 31, 2008 were proved undeveloped reserves.

Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserve data included in the reserve engineer reports assumes that substantial capital expenditures are required to develop such reserves. Although cost and reserve estimates attributable to our natural gas and crude oil reserves have been prepared in accordance with industry standards, we cannot be sure that the estimated costs are accurate, that development will occur as scheduled or that the results of such development will be as estimated.

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

You should not assume that the present value of future net revenues from our proved reserves referred to in this prospectus is the current market value of our estimated natural gas, crude oil and natural gas liquids reserves. In accordance with the requirements of the Securities and Exchange Commission (SEC), the estimated discounted future net cash flows from our proved reserves are based on prices and costs on the date of the estimate, held flat for the life of the properties. Actual future prices and costs may differ materially from those used in the present value estimate. The present value of future net revenues from our proved reserves as of December 31, 2008 was based on a Henry Hub spot market price of $5.71 per MMbtu for natural gas and a West Texas Intermediate posted price of $41.00 per barrel for crude oil on December 31, 2008. If crude oil prices were $1.00 per Bbl lower than the price used, our PV-10 as of December 31, 2008 would have decreased from $290.95 million to $288.15 million. If natural gas prices were $0.10 per Mcf lower than the price used, our PV-10 as of December 31, 2008, would have decreased from $290.95 million to $285.47 million. Any adjustments to the estimates of proved reserves or decreases in the price of crude oil or natural gas may decrease the value of our common stock.

Actual future net cash flows will also be affected by increases or decreases in consumption by oil and gas purchasers and changes in governmental regulations or taxation. The timing of both the production and the incurrence of expenses in connection with the development and production of oil and gas properties affects the timing of actual future net cash flows from proved reserves. In addition, the 10% discount factor, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most appropriate discount factor. The effective interest rate at various times and the risks associated with our business or the oil and gas industry in general will affect the accuracy of the 10% discount factor.

Our estimates of proved reserves and related PV-10 and standardized measure of discounted future net cash flows, which are prepared and presented under existing SEC rules, may change materially as a result of new SEC rules that will go into effect for fiscal years ending on or after December 31, 2009.

This prospectus presents estimates of our proved reserves and related PV-10 and standardized measure of discounted future net cash flows as of December 31, 2008 and as of September 30, 2009, which estimates have been prepared and presented under existing SEC rules. The SEC has adopted new rules that are effective for fiscal years ending on or after December 31, 2009, which will require SEC reporting companies to prepare their reserves estimates using revised reserve definitions and

revised pricing based on 12-month unweighted first-day-of-the-month average pricing. The pricing to be utilized for estimates of our reserves as of December 31, 2009 will be based on an unweighted average twelve month Henry Hub spot price of $3.87 per MMBtu for natural gas and an average West Texas Intermediate posted price of $57.65.

Another impact of the new SEC rules is a general requirement that, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking. This new rule may limit our potential to book additional proved undeveloped reserves as we pursue our drilling program, particularly as we develop our significant acreage in East Texas.

The SEC has released only limited interpretive guidance regarding reporting of reserve estimates under the new rules and may not issue further interpretive guidance on the new rules prior to the end of 2009. We have not determined the impact the new rules may have on our estimates of our proved reserves and related PV-10 and standardized measure of discounted future net cash flows as of December 31, 2009 or as of September 30, 2009, but the impact of the new rules on such estimates, and in particular the estimates of proved undeveloped reserves, could be material.

Our use of 2D and 3D seismic data is subject to interpretation and may not accurately identify the presence of natural gas and crude oil. In addition, the use of such technology requires greater predrilling expenditures, which could adversely affect the results of our drilling operations.

Our decisions to purchase, explore, develop and exploit prospects or properties depend in part on data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are uncertain. For example, we have over 4,200 square miles of 3D data in the South Texas and Gulf Coast regions and 1,130 square miles of 3D data in the Lobo trend in South Texas that our internal prospect generation team uses to develop drilling opportunities in these areas. However, even when used and properly interpreted, 3D seismic data and visualization techniques only assist geoscientists and geologists in identifying subsurface structures and hydrocarbon indicators. They do not allow the interpreter to know if hydrocarbons are present or producible economically. Other geologists and petroleum professionals, when studying the same seismic data, may have significantly different interpretations than our professionals.

In addition, the use of 3D seismic and other advanced technologies require greater predrilling expenditures than traditional drilling strategies, and we could incur losses due to such expenditures. As a result, our drilling activities may not be geologically successful or economical, and our overall drilling success rate or our drilling success rate for activities in a particular area may not improve.

Drilling for and producing natural gas and crude oil are high risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.

Our drilling and operating activities are subject to many risks, including the risk that we will not discover commercially productive reservoirs. Drilling for natural gas and crude oil can be unprofitable, not only from dry holes, but from productive wells that do not produce sufficient revenues to return a profit. In addition, our drilling and producing operations may be curtailed, delayed or canceled as a result of other factors, including:

- unusual or unexpected geological formations and miscalculations;
- pressures;
- fires;
- explosions and blowouts;

pipe or cement failures;

- environmental hazards, such as natural gas leaks, pipeline ruptures and discharges of toxic gases;
- loss of drilling fluid circulation;
- title problems;
- facility or equipment malfunctions;
- unexpected operational events;
- shortages of skilled personnel;
- shortages or delivery delays of equipment and services;
- compliance with environmental and other regulatory requirements;
- natural disasters; and
- adverse weather conditions.

Any of these risks can cause substantial losses, including personal injury or loss of life; severe damage to or destruction of property, natural resources and equipment; pollution; environmental contamination; clean-up responsibilities; loss of wells; repairs to resume operations; and regulatory fines or penalties.

Insurance against all operational risks is not available to us. 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. We carry limited environmental insurance, thus, losses could occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. The occurrence of an event that is not covered in full or in part by insurance could have a material adverse impact on our business activities, financial condition and results of operations.

Our acquisition strategy may subject us to greater risks.

The successful acquisition of properties requires an assessment of recoverable reserves, future natural gas and crude oil prices, operating costs, potential environmental and other liabilities, and other factors beyond our control. Such assessments are necessarily inexact and their accuracy uncertain. In connection with such an assessment, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Such a review, however, will not reveal all existing or potential problems, costs and liabilities, nor will it permit us, as the buyer, to become sufficiently familiar with the properties to fully assess their capabilities or deficiencies. We may not inspect every well and, even when an inspection is undertaken, structural and environmental problems may not necessarily be observable.

We may be unable to successfully integrate the properties and assets we acquire with our existing operations.

Integration of the properties and assets we acquire may be a complex, time consuming and costly process. Failure to timely and successfully integrate these assets and properties with our operations may have a material adverse effect on our business, financial condition and result of operations. The difficulties of integrating these assets and properties present numerous risks, including:

acquisitions may prove unprofitable and fail to generate anticipated cash flows;

we may need to (i) recruit additional personnel and, in this competitive labor market, we cannot be certain that any of our recruiting efforts will succeed, and (ii) expand corporate infrastructure to facilitate the integration of our operations with those associated with the acquired properties, and failure to do so may lead to disruptions in our ongoing businesses or distract our management; and

- our management s attention may be diverted from other business concerns.

We are also exposed to risks that are commonly associated with acquisitions of this type, such as unanticipated liabilities and costs, some of which may be material. As a result, the anticipated benefits of acquiring assets and properties may not be fully realized, if at all.

When we acquire properties, in most cases, we are not entitled to contractual indemnification for pre-closing liabilities, including environmental liabilities.

We generally acquire interests in properties on an as is basis with limited remedies for breaches of representations and warranties, and in these situations we cannot assure you that we will identify all areas of existing or potential exposure. In those circumstances in which we have contractual indemnification rights for pre-closing liabilities, we cannot assure you that the seller will be able to fulfill its contractual obligations. In addition, the competition to acquire producing natural gas and crude oil properties is intense and many of our larger competitors have financial and other resources substantially greater than ours. We cannot assure you that we will be able to acquire producing natural gas and crude oil properties that have economically recoverable reserves for acceptable prices.

We cannot control activities on properties that we do not operate and are unable to control their proper operation and profitability.

We do not operate a significant portion of the properties in which we own an interest. As a result, we have limited ability to exercise influence over, and control the risks associated with, the operations of these properties. The failure of an operator of our wells to adequately perform operations, an operator s breach of the applicable agreements or an operator s failure to act in ways that are in our best interests could reduce our production and revenues. The success and timing of our drilling and development activities on properties operated by others therefore depend upon a number of factors outside of our control, including:

- the nature and timing of drilling and operational activities;
- the timing and amount of capital expenditures;
- the operator s expertise and financial resources;
- the approval of other participants in drilling wells; and
- the operator s selection of suitable technology.

If our access to markets is restricted, it could negatively impact our production, our income and ultimately our ability to retain our leases.

Market conditions or the unavailability of satisfactory natural gas and crude oil transportation arrangements may hinder our access to natural gas and crude oil markets or delay our production. The availability of a ready market for our crude oil and natural gas production depends on a number of factors, including the demand for and supply of natural gas and crude oil 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 such services on acceptable terms could materially harm our business. Our productive properties may be located in areas with limited or no access to pipelines, thereby necessitating delivery by other means, such as trucking, or requiring compression facilities. Such restrictions on our ability to sell our natural gas and crude oil may have several adverse effects, including higher transportation costs, fewer potential purchasers (thereby potentially resulting in a lower selling price) or, in the event we were unable to market and sustain production from a particular lease for an extended time, possible loss of a lease due to lack of production.

Table of Contents

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

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

The potential lack of availability or high cost of drilling rigs, equipment, supplies, personnel and crude oil field services could adversely affect our ability to execute on a timely basis our exploration and development plans within our budget.

When the prices of natural gas and crude oil increase, such as during 2008, we encounter an increase in the cost of securing drilling rigs, equipment and supplies. In addition, larger producers may be more likely to secure access to such equipment by offering more lucrative terms. If we are unable to acquire access to such resources, or can obtain access only at higher prices, our ability to convert our reserves into cash flow could be delayed and the cost of producing those reserves could increase significantly, which would adversely affect our results of operation and financial condition.

Our hedging activities could result in financial losses or reduce our income.

To achieve a more predictable cash flow and to reduce our exposure to adverse fluctuations in the prices of natural gas, crude oil and natural gas liquids, as well as interest rates, we currently, and may in the future, enter into derivative arrangements for a significant portion of our natural gas, crude oil and/or natural gas liquids production and our debt that could result in both realized and unrealized hedging losses. We utilize financial commodity price hedge instruments to minimize exposure to declining prices on our crude oil and natural gas liquids production. As of September 30, 2009, we had 13.9 Bcfe of equivalent production hedged representing 1.8 Bcf, 6.1 Bcf and 3.2 Bcf of natural gas hedges in place and 86 MBbl, 250 MBbl and 124 MBbl of crude oil hedges in place for the fourth quarter of 2009, 2010 and 2011, respectively. The average price of our natural gas and crude oil hedges in place is $8.19/MMBtu and $86.03/Bbl for the fourth quarter of 2009, $7.71/MMBtu and $83.02/Bbl in the year 2010 and $7.32/MMBtu and $66.50/Bbl in the year 2011. As of September 30, 2009, we had entered into interest rate swap agreements with a total notional amount of $200.0 million related to our indebtedness. Under our interest rate swap agreements, we receive interest at a floating rate equal to one-month LIBOR and pay interest at a fixed rate of 1.50% for $50.0 million and pay interest at 2.90% for $150.0 million.

Our actual future production may be significantly higher or lower than we estimate at the time we enter into hedging transactions for such period. If the actual amount is higher than we estimate, we will have greater commodity price exposure than we intended. If the actual amount is lower than the nominal amount that is subject to our derivative financial instruments, we might be forced to satisfy all or a portion of our derivative transactions without the benefit of the cash flow from our sale or purchase of the underlying physical commodity, resulting in a substantial diminution of our liquidity. As a result of our interest rate swap agreements, we may fail to benefit when rates fall, to the extent we have agreed to pay interest at a fixed rate, or face a greater degree of exposure when rates increase, to the extent we have agreed to pay interest at a floating rate. As a result of these factors, our hedging activities may not be as effective as we intend in reducing the volatility of our cash flows, and in certain circumstances may actually increase the volatility of our cash flows.

Table of Contents

Competition in the oil and gas industry is intense, and many of our competitors have resources that are greater than ours.

We operate in a highly competitive environment for acquiring prospects and productive properties, marketing natural gas and crude oil, and securing equipment and trained personnel. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours. Those companies may be able to develop and acquire more prospects and productive properties than our financial our personnel resources permit. Our ability to acquire additional prospects and discover reserves in the future will depend on our ability to evaluate and select suitable properties and consummate transactions in a highly competitive environment. Also, there is substantial competition for capital available for investment in the oil and gas industry. Our larger competitors may be better able to withstand sustained periods of unsuccessful drilling and absorb the burden of changes in laws and regulations more easily than we can, which would adversely affect our competitive position. 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.

We depend on our senior management team and other key personnel. Accordingly, the loss of any of these individuals could adversely affect our business, financial condition and the results of operations and future growth.

Our success is largely dependent on the skills, experience and efforts of our people. The loss of the services of one or more members of our senior management team or of our other employees with critical skills needed to operate our business could have a negative effect on our business, financial conditions and results of operations and future growth. These persons include the executive officers listed in Management Executive Officers and Directors. Our ability to manage our growth, if any, will require us to continue to train, motivate and manage our employees and to attract, motivate and retain additional qualified personnel. Competition for these types of personnel is intense and we may not be successful in attracting, assimilating and retaining the personnel required to grow and operate our business profitably.

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

Our operations are subject to complex and stringent laws and regulations. In order to conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state and local governmental authorities. We may incur substantial costs in order to maintain compliance with these existing laws and regulations. In addition, our costs of compliance may increase if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations. For instance, we may be unable to obtain all necessary permits, approvals and certificates for proposed projects. Alternatively, we may have to incur substantial expenditures to obtain, maintain or renew authorizations to conduct existing projects. If a project is unable to function as planned due to changing requirements or public opposition, we may suffer expensive delays, extended periods of non-operation or significant loss of value in a project. All such costs may have a negative effect on our business and results of operations.

Our business is subject to federal, state and local regulations as interpreted and enforced by governmental agencies and other bodies vested with much authority relating to the exploration for, and the development, production, transportation and marketing of, natural gas, crude oil and natural gas liquids. Failure to comply with such laws and regulations, as interpreted and enforced, could have a material adverse effect on us.

Table of Contents

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 require the disclosure of chemicals used by the oil and natural gas industry in the hydraulic fracturing process. Hydraulic fracturing is an important and commonly used process in the completion of unconventional natural gas wells in shale formations. This process involves the injection of water, sand and chemicals under pressure into rock formations to stimulate natural gas production. Sponsors of these bills, which are currently pending in the Energy and Commerce Committee and the Environmental and Public Works Committee of the House of Representatives and Senate, respectively, have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. The proposed legislation would require the reporting and public disclosure of chemicals used in the fracturing process, which could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, these bills, if adopted, could establish an additional level of regulation at the federal level that could lead to operational delays or increased operating costs and could result in additional regulatory burdens that could make it more difficult to perform hydraulic fracturing and increase our costs of compliance and doing business.

Our operations expose us to potentially substantial costs and liabilities with respect to environmental, health and safety matters.

We may incur substantial costs and liabilities as a result of environmental, health and safety requirements applicable to our crude oil and natural gas operations and other activities. These costs and liabilities could arise under a wide range of federal, state and local environmental, health and safety laws and regulations that cover, among other things, emissions into the air and water, habitat and endangered species protection, the containment and disposal of hazardous substances, oil field waste and other waste materials, the use of underground injection wells, and wetlands protection. These laws and regulations are complex, change frequently and have tended to become increasingly stringent over time. Failure to comply with environmental, health and safety laws or regulations may result in assessment of administrative, civil and criminal penalties, imposition of cleanup and site restoration costs and liens, the suspension or revocation of necessary permits, licenses and authorizations, the requirement that additional pollution controls be installed and the issuance of orders enjoining or limiting our current or future operations. Compliance with these laws and regulations also increases the cost of our operations and may prevent or delay the commencement or continuance of a given operation.

Under certain environmental laws that impose strict, joint and several liability, we may be required to remediate our contaminated properties regardless of whether such contamination resulted from the conduct of others or from consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. In addition, claims for damages to persons, property or natural resources may result from environmental and other impacts of our operations. Moreover, new or modified environmental, health or safety laws, regulations or enforcement policies could be more stringent and impose unforeseen liabilities or significantly increase compliance costs. Therefore, the costs to comply with environmental, health, or safety laws or regulations or the liabilities incurred in connection with them could significantly and adversely affect our business, financial condition or results of operations. In addition, many countries, as well as more than one-third of the states have agreed to regulate emissions of greenhouse gases, including methane, a primary component of natural gas, and carbon dioxide, a byproduct of burning natural gas and oil. National greenhouse gas legislation and regulation is in early stages of development in the U.S., and we are currently unable to determine the impact of potential greenhouse gas emission control requirements. Mandatory greenhouse gas emissions reductions may impose increased costs on our business and could adversely impact some of our operations. It is possible that broader national or regional greenhouse gas reduction requirements may directly or indirectly have an adverse impact on natural

26

gas or other fuel markets, including future demand for the natural gas, crude oil and natural gas liquids that we produce. See Business Environmental Regulations.

If we are unable to successfully prevent or address material weaknesses in our internal control over financial reporting, or any other control deficiencies, our ability to report our financial results on a timely and accurate basis and to comply with disclosure and other reporting requirements may be adversely affected.

While we have taken actions designed to address compliance with the internal control, disclosure control and other requirements of the Sarbanes-Oxley Act of 2002 and the rules and regulations promulgated by the SEC implementing these requirements, there are inherent limitations in our ability to control all circumstances. Our management, including our Chief Executive Officer and Chief Financial Officer, does not expect that our internal controls and disclosure controls will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. For example, for the quarter ended March 31, 2007, our management concluded that our historical documentation of related tax positions could have resulted in a material misstatement to our annual or interim financial statements and, accordingly, concluded that this deficiency was a material weakness. Although this material weakness was subsequently remedied, if we are unable to successfully prevent or address these and other material weaknesses in our internal control systems, our ability to report our financial results on a timely and accurate basis and to comply with disclosure and other reporting requirements may be adversely affected.

Derivatives regulation could restrict our ability to execute commodity derivative instruments as a hedge against fluctuating commodity prices.

Various measures are being proposed by committees of Congress, the U.S. Treasury Department, and other agencies to restrict the use of over-the-counter (OTC) derivative instruments. These proposals include, but are not limited to, requiring cash collateral on all OTC derivatives and requiring all OTC derivatives to be executed and settled through an exchange system.

Although we do not currently know the exact form any final legislation or rule-making activity will take, any restriction on the use of OTC instruments could have a significant impact on our business. Limits on the use of OTC instruments could significantly reduce our ability to execute strategic price hedges against commodity price volatility. In addition, cash collateral requirements could create significant liquidity issues and exchange system trades may restrict our ability to execute derivative instruments to fit our strategic needs.

Risks Related to an Investment in Our Common Stock and this Offering

One stockholder will, after the completion of this offering, hold a significant number of our shares, which will limit your ability to influence corporate activities and may adversely affect the market price of our common stock, and that stockholder s interests may conflict with the interests of our other stockholders.

After completion of the Preferred Stock Conversion and the issuance of shares of common stock in this offering, we expect, based on the midpoint of the range provided on the cover of this prospectus, there will be approximately 33.1 million shares of our common stock outstanding. Of that amount, we expect that 10.3 million shares of our common stock will be held by Oaktree Holdings. As a result, Oaktree Holdings will own or control outstanding common stock representing, in the aggregate, an approximate 31% voting interest in us. As a result of this stock ownership, Oaktree Holdings will possess significant influence over matters requiring approval by our stockholders, including the adoption of amendments to our certificate of incorporation and bylaws and significant corporate transactions. Such ownership and control may also have the effect of delaying or preventing

Table of Contents

a future change of control, impeding a merger, consolidation, takeover or other business combination or discouraging a potential acquirer from making a tender offer or otherwise attempting to obtain control of our company.

Oaktree Holdings and its affiliates engage, from time to time in the ordinary course of their respective businesses, in the trading securities of, and investing in, energy companies. As a result, conflicts may arise between the interests of Oaktree Holdings, on the one hand, and the interests of our other stockholders, on the other hand. Oaktree Holdings may, from time to time, compete directly or indirectly with us or prevent us from taking advantage of corporate opportunities. Oaktree Holdings may also pursue acquisition opportunities that may be complementary to our business, and as a result, those acquisition opportunities may not be available to us.

The price of our common stock may fluctuate significantly, and you could lose all or part of your investment.

Volatility in the market price of our common stock price may prevent you from being able to sell your common stock at or above the price you paid for your common stock. The market price for our common stock could fluctuate significantly for various reasons, including:

- our operating and financial performance and prospects;
- our quarterly or annual earnings or those of other companies in our industry;
- conditions that impact demand for natural gas, crude oil and natural gas liquids;
- future announcements concerning our business;
- changes in financial estimates and recommendations by securities analysts;
- actions of competitors;
- market and industry perception of our success, or lack thereof, in pursuing our growth strategy;
- strategic actions by us or our competitors, such as acquisitions or restructurings;
- changes in government and environmental regulation;
- general market, economic and political conditions;
- changes in accounting standards, policies, guidance, interpretations or principles;
- sales of common stock by us or members of our management team; and
- natural disasters, terrorist attacks and acts of war.

See Risks Related to Our Business.

In addition, in recent years, the stock market has experienced significant price and volume fluctuations. This volatility has had a significant impact on the market price of securities issued by many companies, including companies in our industry. The changes frequently appear to occur without regard to the operating performance of the affected companies. Hence, the price of our common stock could fluctuate based upon factors that have little or nothing to do with our company, and these fluctuations could materially reduce our share price.

Table of Contents

We have no plans to pay regular dividends on our common stock, so you may not receive funds without selling your common stock.

Our board of directors presently intends to retain all of our earnings for the expansion of our business; therefore, we have no plans to pay regular dividends on our common stock. Any payment of future dividends will be at the discretion of our board of directors and will depend on, among other things, our earnings, financial condition, capital requirements, level of indebtedness, statutory and contractual restrictions applying to the payment of dividends, and other considerations that our board of directors deems relevant. Also, the provisions of our revolving credit facility and second lien term loan agreement restrict the payment of dividends. Accordingly, you may have to sell some or all of your common stock in order to generate cash flow from your investment.

Future sales or the possibility of future sales of a substantial amount of our common stock may depress the price of shares of our common stock.

Future sales or the availability for sale of substantial amounts of our common stock in the public market could adversely affect the prevailing market price of our common stock and could impair our ability to raise capital through future sales of equity securities.

Upon consummation of this offering and the Preferred Stock Conversion, based on the midpoint of the range provided on the cover of this prospectus, there will be 33,134,607 shares of our common stock outstanding. All shares of our common stock sold in this offering will be freely transferable without restriction or further registration under the Securities Act of 1933, as amended, or the Securities Act.

We may issue shares of our common stock or other securities from time to time as consideration for future acquisitions and investments. If any such acquisition or investment is significant, the number of shares of our common stock, or the number or aggregate principal amount, as the case may be, of other securities that we may issue may in turn be substantial. We may also grant registration rights covering those shares of our common stock or other securities in connection with any such acquisitions and investments.

As of December 4, 2009, we had 2.0 million options to purchase shares of our common stock outstanding, 1.2 million of which were vested.

We cannot predict the size of future issuances of our common stock or the effect, if any, that future issuances and sales of our common stock will have on the market price of our common stock. Sales of substantial amounts of our common stock (including shares of our common stock issued in connection with an acquisition), or the perception that such sales could occur, may adversely affect prevailing market prices for our common stock.

Our organizational documents may impede or discourage a takeover, which could deprive our investors of the opportunity to receive a premium for their shares.

Provisions of our certificate of incorporation and bylaws may make it more difficult for, or prevent a third party from, acquiring control of us without the approval of our board of directors. These provisions:

- permit us to issue, without any further vote or action by the stockholders, additional shares of preferred stock in one or more series and, with respect to each such series, to fix the number of shares constituting the series and the designation of the series, the voting powers (if any) of the shares of the series, and the preferences and relative, participating, optional, and other special rights, if any, and any qualification, limitations or restrictions of the shares of such series;

29

require special meetings of the stockholders to be called by the Chairman of the Board, the Chief Executive Officer, the President, or by resolution of a majority of the board of directors;

require business at special meetings to be limited to the stated purpose or purposes of that meeting;

require that stockholder action be taken at a meeting rather than by written consent, unless approved by our board of directors;

require that stockholders follow certain procedures, including advance notice procedures, to bring certain matters before an annual meeting or to nominate a director for election; and

permit directors to fill vacancies in our board of directors.

The foregoing factors, as well as the significant common stock ownership by Oaktree Holdings, could discourage potential acquisition proposals and could delay or prevent a change of control. See Description of Capital Stock.

After this offering, we will be subject to the Delaware business combination law.

After this offering, we will be subject to the provisions of Section 203 of the Delaware General Corporation Law. In general, Section 203 prohibits a publicly held Delaware corporation from engaging in a business combination with an interested stockholder for a period of three years after the date of the transaction in which the person became an interested stockholder, unless the business combination is approved in a prescribed manner.

Section 203 defines a business combination as a merger, asset sale or other transaction resulting in a financial benefit to the interested stockholders. Section 203 defines an interested stockholder as a person who, together with affiliates and associates, owns, or, in some cases, within three years prior, did own, 15% or more of the corporation s voting stock. Under Section 203, a business combination between us and an interested stockholder is prohibited unless:

our board of directors approved either the business combination or the transaction that resulted in the stockholders becoming an interested stockholder prior to the date the person attained the status;

upon consummation of the transaction that resulted in the stockholder becoming an interested stockholder, the interested stockholder owned at least 85% of our voting stock outstanding at the time the transaction commenced, excluding, for purposes of determining the number of shares outstanding, shares owned by persons who are directors and also officers and issued employee stock plans, under which employee participants do not have the right to determine confidentially whether shares held under the plan will be tendered in a tender or exchange offer; or

the business combination is approved by our board of directors on or subsequent to the date the person became an interested stockholder and authorized at an annual or special meeting of the stockholders by the affirmative vote of the holders of at least 662/3% of the outstanding voting stock that is not owned by the interested stockholder.

This provision has an anti-takeover effect with respect to transactions not approved in advance by our board of directors, including discouraging takeover attempts that might result in a premium over the market price for the shares of our common stock. With approval of our stockholders, we could amend our certificate of incorporation in the future to elect not to be governed by the anti-takeover law. Section 203 of the Delaware General Corporation Law will not apply to Oaktree Holdings.

Table of Contents

We have blank check preferred stock.

Our certificate of incorporation authorizes the board of directors to issue preferred stock without further stockholder action in one or more series and to designate the dividend rate, voting rights and other rights preferences and restrictions. The issuance of preferred stock could have an adverse impact on holders of common stock. Preferred stock is senior to common stock. Additionally, preferred stock could be issued with dividend rights senior to the rights of holders of common stock. Finally, preferred stock could be issued as part of a poison pill, which could have the effect of deterring offers to acquire our company. See Description of Capital Stock Anti-Takeover Effects of Delaware Laws and Our Charter and Bylaws Provisions.

The holders of our common stock do not have cumulative voting rights, preemptive rights or rights to convert their common stock to other securities.

We are authorized to issue 200.0 million shares of common stock, $0.001 par value per share. As of December 4, 2009, there were 6.4 million shares of common stock issued and outstanding. After giving effect to this offering and the Preferred Stock Conversion, based on the midpoint of the range provided on the cover of this prospectus, there will be 33.1 million shares of common stock issued and outstanding. Since the holders of our common stock do not have cumulative voting rights, the holders of a majority of the shares of common stock present, in person or by proxy, will be able to elect all of the members of our board of directors. The holders of shares of our common stock do not have preemptive rights or rights to convert their common stock into other securities.

Prior to this offering, our common stock has been thinly traded and there has been no active trading market for our common stock and an active trading market may not develop.

The trading volume of our common stock has historically been low and reliable market quotations for our common stock have not been available, partially due to the fact that we are not listed on an exchange and our common stock is only traded over-the-counter. An active trading market for our common stock may not develop or, if developed, may not continue, and a holder of any of our securities may find it difficult to dispose of, or to obtain accurate quotations as to the market value of such securities.

The impairment of financial institutions could adversely affect us.

We have exposure to different counterparties, and we have entered into transactions with counterparties in the financial services industry specifically, with members of our bank group. These transactions could expose us to credit risk in the event of default of our counterparty. We have exposure to these financial institutions in the form of derivative transactions in connection with our hedges. We also maintain insurance policies with insurance companies to protect us against certain risks inherent in our business. In addition, if any lender under our credit facility is unable to fund its commitment, our liquidity could be reduced by an amount up to the aggregate amount of such lender s commitment under our credit facility.

We have a substantial amount of indebtedness, which may adversely affect our cash flow and our ability to operate our business.

As of September 30, 2009, pro forma for the application of net proceeds from this offering (estimated based upon the midpoint of the range of the offering price on the cover of this prospectus) we had outstanding debt of $175.9 million under our credit agreements. Our substantial level of indebtedness increases the possibility that we may be unable to pay, when due, the principal of, interest on, or other amounts due in respect of our indebtedness. Our substantial indebtedness,

Table of Contents

combined with our other financial obligations and contractual commitments, could have other important consequences, including the following:

funds available for our operations and general corporate purposes or for capital expenditures will be reduced as a result of the dedication of a portion of our consolidated cash flow from operations to the payment of the principal and interest on our indebtedness;

we may be more highly leveraged than certain of our competitors, which may place us at a competitive disadvantage;

certain of the borrowings under our debt agreements have floating rates of interest, which causes us to be vulnerable to increases in interest rates;

our degree of leverage could make us more vulnerable to downturns in general economic conditions;

our ability to plan for, or react to, changes in our business and the industry in which we operate may be limited; and

our ability to obtain additional financing on satisfactory terms to fund our working capital requirements, capital expenditures, investments, debt service requirements and other general corporate requirements may be reduced.

In addition, our revolving credit facility and second lien term loan agreement contain a number of significant covenants that place limitations on our activities and operations, including those relating to:

creation of liens;

hedging;

mergers, acquisitions, asset sales or dispositions;

payments of dividends;

incurrence of additional indebtedness; and

certain leases and investments outside of the ordinary course of business.

Our credit agreements require us to maintain compliance with specified financial ratios and satisfy certain financial condition tests. Our ability to comply with these ratios and financial condition tests may be affected by events beyond our control, and we cannot assure you that we will meet these ratios and financial condition tests. These financial ratio restrictions and financial condition tests could limit our ability to obtain future financings, make needed capital expenditures, withstand a future downturn in our business or the economy in general or otherwise conduct necessary or desirable corporate activities.

A breach of any of these covenants or our inability to comply with the required financial ratios or financial condition tests could also result in a default under our credit agreements. A default, if not cured or waived, could result in all of our indebtedness becoming immediately due and payable. If that should occur, we may not be able to pay all such debt or to borrow sufficient funds to refinance it. See Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Capital resources for further information regarding future compliance with these covenants. Even if new financing were then available, it may not be on terms that are acceptable to us. See Recent market events and conditions, including disruptions in the U.S. and international credit markets and other financial systems and the deterioration of the U.S. and global economic conditions, could, among other things, impede access to capital or increase the cost of capital, which would have an adverse effect on our ability to fund our working capital and other capital requirements and Our development and exploration operations, including on our East Texas resource play acreage, require substantial capital, and we may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a loss of properties and a decline in our natural gas, crude oil and natural gas liquids reserves.

Table of Contents

Changes to current laws may affect our ability to take certain deductions.

Substantive changes to the existing federal income tax laws have been proposed that, if adopted, would affect, among other things, our ability to take certain deductions related to our operations, including depletion deductions, deductions for intangible drilling and development costs and deductions for United States production activities. These changes, if enacted into law, could negatively affect our financial condition and results of operations.

Our ability to use our net operating loss carryforwards may be subject to limitation and may result in increased future tax liability to us.

Generally, a change of more than 50% in the ownership of a corporation s stock, by value, over a three-year period constitutes an ownership change for U.S. federal income tax purposes. An ownership change may limit a company s ability to use its net operating loss carryforwards attributable to the period prior to such change. The number of shares of common stock that we issue in connection with this offering may be sufficient, taking into account prior or future shifts in our ownership over a three-year period, to cause us to undergo an ownership change. As a result, if we earn net taxable income, our ability to use our pre-change net operating loss carryforwards to offset U.S. federal taxable income may become subject to limitations, which could potentially result in increased future tax liability to us. In addition, the carrying value of any tax asset related to our net operating loss carryforwards could be significantly reduced.

Table of Contents

CAUTIONARY STATEMENT CONCERNING FORWARD-LOOKING STATEMENTS

We make forward-looking statements throughout this prospectus within the meaning of Section 27A of the Securities Act, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended (the Exchange Act).

These forward-looking statements include, but are not limited to, statements regarding:

- estimates of proved reserve quantities and net present values of those reserves;
- reserve potential;
- business strategy;
- estimates of future commodity prices;
- amounts, timing and types of capital expenditures and operating expenses;
- expansion and growth of our business and operations;
- expansion and development trends of the oil and gas industry;
- acquisitions of natural gas and crude oil properties;
- production of crude oil and natural gas reserves;
- exploration prospects;
- wells to be drilled and drilling results;
- operating results and working capital; and
- future methods and types of financing.

Whenever you read a statement that is not simply a statement of historical fact (such as when we describe what we believe, expect or anticipate will occur, and other similar statements), you must remember that our expectations may not be correct, even though we believe they are reasonable. We caution that a number of factors could cause future production, revenues and expenses to differ materially from our expectations. We do not guarantee that the transactions and events described in this prospectus will happen as described (or that they will happen at all). The forward-looking information contained in this prospectus is generally located in the material provided under the headings Business, Risk Factors, and Management s Discussion and Analysis of Financial Condition and Results of Operations but may be found in other locations as well. These forward-looking statements generally relate to our plans and objectives for future operations and are based upon our management s reasonable estimates of future results and trends. For a discussion of risk factors affecting our business, see Risk Factors.

Table of Contents

USE OF PROCEEDS

We estimate that our net proceeds from the sale of shares of our common stock in this offering, after deducting underwriting discounts and commissions and estimated offering expenses, will be approximately $117.6 million, assuming an offering price of $7.00 per share, which is the midpoint of the range provided on the cover page of this prospectus.

We intend to use the net proceeds from this offering to repay approximately $107.6 million in aggregate principal amount of loans outstanding under our revolving credit facility and $10 million in aggregate principal amount of indebtedness under our $10 million unsecured promissory note due to Wells Fargo Bank, National Association. At December 4, 2009 and after application of proceeds from our $10 million unsecured promissory note, we had $129.5 million of indebtedness outstanding under our revolving credit facility. This indebtedness matures on May 8, 2011, and at December 4, 2009 had a weighted average interest rate of 3.76% per annum. The indebtedness under our $10 million unsecured promissory note bears interest at a rate per annum equal to two-month LIBOR plus 2% and matures on January 15, 2010. For a description of our revolving credit facility and our $10 million unsecured promissory note, please see Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Capital resources.

Affiliates of certain of the underwriters are lenders under our existing revolving credit facility and therefore will receive a portion of the net proceeds of this offering. See Underwriting.

A $1.00 increase (decrease) in the assumed initial public offering price of $7.00 per share would increase (decrease) the net proceeds from this offering by approximately $16.9 million, assuming no change in the number of shares offered by us as included on the cover page of this prospectus and after deducting the estimated underwriting discounts and commissions and estimated offering expenses payable by us.

DIVIDEND POLICY

We have never declared or paid cash dividends on our common stock or our preferred stock. Each share of our Series G Preferred Stock is entitled to a quarterly cash dividend, if, as and when declared, that cumulates and compounds quarterly whether or not dividends in a quarter are declared or paid, equal to 8% per annum based on the then-current liquidation preference. Dividends on our Series G Preferred Stock have accumulated since 2005, but have not been declared or paid. As of September 30, 2009, accumulated dividends on the Series G Preferred Stock equaled approximately $17.7 million. We expect to convert all shares of our Series G Preferred Stock and the accumulated dividends on such shares in connection with the closing of this offering. See Prospectus Summary Preferred Stock Conversion. Although we have not, and are not required to, pay a cash dividend on our Series H Preferred Stock, we have paid a quarterly dividend of one share of our common stock (as adjusted for our 1-for-10 reverse stock split in September 2006) on our outstanding shares of Series H Preferred Stock, as required by its Certificate of Designations, since 2005. The provisions of our revolving credit facility, second lien term loan agreement and preferred stock restrict the payment of dividends. We currently intend to retain all available funds and any future earnings for use in the operation of our business and to fund future growth. We do not anticipate paying any cash dividends on our common stock in the foreseeable future.

Table of Contents

CAPITALIZATION

The following table sets forth cash and cash equivalents and capitalization as of September 30, 2009:

on a historical basis;

on a pro forma basis to give effect to the Preferred Stock Conversion (estimated based on the mid-point of the range of the offering price on the cover of this prospectus), the issuance of $12 million in unsecured promissory notes and the repayment of loans under our revolving credit facility with proceeds of one of such promissory notes; and

on a pro forma basis as further adjusted to give effect to this offering and the application of the estimated net proceeds of this offering (estimated based on the mid-point of the range of the offering price on the cover of this prospectus).

This table should be read together with Use of Proceeds, Selected Historical Consolidated Financial Data, Management s Discussion and Analysis of Financial Condition and Results of Operations and the consolidated financial statements and notes to those statements, in each case, included elsewhere in this prospectus.

	As of September 30, 2009		
	Historical	Pro Forma	Pro Forma As Further Adjusted[1]
	(In thousands, except per share data)		
Cash and cash equivalents	$	$	$
Total current debt			
Unsecured promissory note		10,000	
Current portion of long-term debt	1,526		
	$ 1,526	$ 10,000	$
Total long-term debt, net of current portion			
Revolving credit facility[2]	140,000	131,526	23,941
Second lien term loan agreement	150,000	150,000	150,000
Subordinated unsecured promissory note		2,000	2,000
	$ 290,000	$ 283,526	$ 175,941
Total debt	$ 291,526	$ 293,526	$ 175,941
Stockholders equity			
Series G Preferred Stock	$ 1	$	$
Series H Preferred Stock			
Common stock	7	15	33

Additional paid-in capital	97,566	97,558	215,125
Retained earnings	9,353	9,353	9,353
Treasury stock	(384)	(384)	(384)
Total stockholders equity	$ 106,543	$ 106,542	$ 224,127
Total capitalization	$ 398,069	$ 400,068	$ 400,068

36

(1) A $1.00 increase (decrease) in the assumed $7.00 per share initial public offering price would decrease (increase) long-term debt, including current maturities, by $16.9 million and increase (decrease) each of additional paid-in capital and total stockholders equity by $18.0 million, assuming the number of shares offered by us, as set forth on the cover page of this prospectus, remains the same.

(2) As of December 4, 2009, and after application of proceeds from our $10 million unsecured promissory note, we had $129.5 million in aggregate indebtedness outstanding under our revolving credit facility. After this offering, we expect that we will have approximately $83.1 million in available borrowing capacity under our revolving credit facility. Also, if we close the sale of substantially all of our Southwest Louisiana properties, we expect to pay down our revolving credit facility by an additional $10.2 million. Effective December 7, 2009, we entered into an amendment to our revolving credit facility that, among other things, amended certain of our financial covenants and our debt incurrence covenant and provided for redetermination of our borrowing base at January 1, 2010. See Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Capital resources Revolving Credit Facility.

MARKET FOR OUR COMMON STOCK

Our common stock is traded on the Over-the-Counter Bulletin Board (the OTCBB) under the symbol CXPO.OB. We have applied to list our common stock on the NASDAQ Global Market under the symbol CXPO.

As of December 4, 2009, the last reported sales price of our common stock on the OTCBB was $6.60 per share of common stock and there were 6,416,401 shares of our common stock outstanding held by approximately 275 holders of record. The following table sets forth the range of high and low bid quotation prices per share of our common stock as reported by the OTCBB. The quotations reflect inter-dealer prices, without retail mark-up, mark-down or commissions, and may not represent actual transactions.

	Range of Reported High and Low Bid Quotations[1]		Average Daily Trading Volume
	High	Low	
2006			
First Quarter	$ 9.50	$ 5.60	4,008
Second Quarter	$ 8.90	$ 6.30	2,497
Third Quarter	$ 7.90	$ 6.40	2,646
Fourth Quarter	$ 7.30	$ 5.20	4,762
2007			
First Quarter	$ 6.20	$ 5.25	2,129
Second Quarter	$ 7.55	$ 5.25	4,046
Third Quarter	$ 8.35	$ 7.15	6,110
Fourth Quarter	$ 19.35	$ 7.65	31,362
2008			
First Quarter	$ 18.50	$ 9.10	22,038
Second Quarter	$ 17.50	$ 8.20	22,773
Third Quarter	$ 16.20	$ 7.23	12,932
Fourth Quarter	$ 7.43	$ 2.85	6,533
2009			
First Quarter	$ 4.60	$ 0.80	5,272
Second Quarter	$ 4.65	$ 1.75	7,173
Third Quarter	$ 4.30	$ 2.26	6,492
Fourth Quarter (through December 4, 2009)	$ 8.25	$ 2.40	15,331

(1) In September 2006, we effected a reverse stock split where each ten shares of outstanding common stock were exchanged for one new share of common stock. All periods presented have been adjusted to reflect the effects of the reverse stock split.

SELECTED HISTORICAL CONSOLIDATED FINANCIAL DATA

The following table sets forth our selected historical consolidated financial data as of the dates and for the periods indicated. The selected historical consolidated financial data as of December 31, 2004, 2005, 2006, 2007 and 2008 and for each of the five years in the period ended December 31, 2008 have been derived from our audited consolidated financial statements and related notes included elsewhere in this prospectus. The historical consolidated financial data for the nine months ended September 30, 2008 and 2009 have been derived from our unaudited consolidated financial statements and, in the opinion of our management, have been prepared on a basis consistent with our audited consolidated financial statements and reflect all adjustments, consisting of normal recurring adjustments necessary for a fair presentation of the financial position and results of operations for the periods presented. The consolidated results of operations for any period are not necessarily indicative of the results to be expected for any future period. The selected historical consolidated financial data provided below should be read in conjunction with, and are qualified by reference to, Management s Discussion and Analysis of Financial Condition and Results of Operations and the consolidated financial statements and related notes thereto included elsewhere in this prospectus.

	Year Ended December 31,					Nine Months Ended September 30,	
	2004	**2005**	**2006**	**2007**	**2008**	**2008**	**2009**
						(Unaudited)	
	(In thousands, except per share data)						
Statement of Operations Data							
Operating revenues	$ 11,208	$ 17,683	$ 21,659	$ 109,543	$ 186,768	$ 151,801	$ 86,251
Operating expenses							
Lease operating expenses	4,613	5,334	5,633	12,034	20,825	15,363	13,518
Production and ad valorem taxes	267	251	1,895	11,702	16,266	14,355	6,061
Exploration expenses	433	750	673	3,174	9,965	1,877	2,873
Depreciation, depletion and amortization	2,257	3,209	4,035	30,796	50,467	36,030	41,599
Impaired assets of oil and gas properties[1]	61	3,689	3,150	4,362	35,954	25,799	
General and administrative expenses	2,019	3,773	8,730	14,542	22,406	17,819	13,381
Loss (gain) on sale of assets[2]	2,034	39	2	(683)	(15,210)	(15,272)	19
Total operating expenses	11,684	17,045	24,118	75,927	140,673	95,971	77,451
Income (loss) from operations[3]	(476)	638	(2,459)	33,616	46,095	55,830	8,800

Other income (expense)							
Interest expense	(4,154)	(1,302)	(109)	(14,949)	(21,109)	(15,871)	(16,349)
Other financing costs	(1,472)	(1,956)	(228)	(1,322)	(1,501)	(1,174)	(1,110)
Loss from equity in investments		(72)	(2)				
Unrealized gain (loss) on derivative instruments	(1,506)	(1,642)	6,082	(18,186)	49,409	1,665	(17,238)
Forgiveness of debt	12,476						
Total other income (expense)	5,344	(4,972)	5,743	(34,457)	26,799	(15,380)	(34,697)
Income (loss) before income taxes	4,868	(4,334)	3,284	(841)	72,894	40,450	(25,897)
Income tax benefit (expense)	3,204	791	(1,425)	410	(26,691)	(15,105)	9,080
Net income (loss)	8,072	(3,543)	1,859	(431)	46,203	25,345	(16,817)
Preferred stock dividends	(455)	(3,563)	(3,649)	(4,453)	(4,234)	(3,164)	(3,353)
Net income (loss) available to common stockholders	$ 7,617	$ (7,106)	$ (1,790)	$ (4,884)	$ 41,969	$ 22,181	$ (20,170)

Table of Contents

	Year Ended December 31,					Nine Months Ended September 30,	
	2004	2005	2006	2007	2008	2008	2009
						(Unaudited)	
	(In thousands, except per share data)						
Net Income (Loss) Per Share Information							
Basic							
Weighted average shares outstanding	1,854	2,674	3,231	4,330	5,371	5,225	6,301
Net income (loss) per share	$ 4.11	$ (2.66)	$ (0.55)	$ (1.13)	$ 7.81	$ 4.25	$ (3.20)
Pro forma weighted average shares outstanding[(4)]					31,725	30,778	31,855
Pro forma net income (loss) per share[(4)]					$ 1.46	$ 0.82	$ (0.53)
Diluted							
Weighted average shares outstanding	3,162	2,674	3,231	4,330	10,360	10,289	6,301
Net income (loss) per share	$ 2.41	$ (2.66)	$ (0.55)	$ (1.13)	$ 4.46	$ 2.46	$ (3.20)
Pro forma weighted average shares outstanding[(4)]					31,930	31,051	31,855
Pro forma net income (loss) per share[(4)]					$ 1.45	$ 0.82	$ (0.53)
Balance Sheet Data							
Current assets	$ 3,809	$ 5,825	$ 4,232	$ 36,481	$ 46,348	$ 42,195	$ 29,529
Property and equipment, net	50,123	54,223	76,547	356,489	449,156	417,977	425,236
Noncurrent assets	3,944	3,067	3,924	5,965	16,042	7,536	7,716
Total assets	57,876	63,115	84,703	398,935	511,546	467,708	462,481
Current liabilities	37,249	6,856	10,932	48,879	83,990	67,441	41,394
Long-term liabilities	1,950	3,454	12,445	280,403	305,933	300,361	314,545
Total stockholders equity	18,677	52,805	61,326	69,653	121,623	99,906	106,542
Total liabilities and stockholders equity	$ 57,876	$ 63,115	$ 84,703	$ 398,935	$ 511,546	$ 467,708	$ 462,481
Other Financial Data							
Adjusted EBITDAX[(5)]	$ 4,309	$ 8,296	$ 9,219	$ 76,003	$ 132,707	$ 108,715	$ 55,160
Capital expenditures							
Acquisition of oil and gas properties	$	$	$	$ 253,434	$ 58,482	$ 58,032	$ (494)
Other capital expenditures[(6)]	6,142	10,798	21,777	59,049	141,795	82,577	16,545

Total	$ 6,142	$ 10,798	$ 21,777	$ 312,483	$ 200,277	$ 140,609	$ 16,051

(1) For the year ended December 31, 2008, includes (i) an impairment expense of $10.2 million in December 2008 with respect to our Grand Lake Field in Southwest Louisiana, resulting from negative reserve revisions resulting from year end low commodity prices, and (ii) $25.8 million in asset impairments in the nine months ended September 30, 2008 resulting from our capital investment in the Rodessa formation within the Madisonville Field.

(2) For the year ended December 31, 2008 and the nine months ended September 30, 2008, includes a gain of $15.6 million resulting from the disposition of our interest in the Barnett Shale Play in January 2008.

(3) Non-cash equity-based compensation charges were $5.4 million, $4.7 million and $3.8 million, in 2008, 2007 and 2006, respectively. Non-cash equity-based compensation charges were $1.9 million and $4.5 million for the nine months ended September 30, 2009 and 2008, respectively.

(4) On an adjusted pro forma basis to give effect to this offering and the Preferred Stock Conversion assuming the conversion occurred at the beginning of the period presented.

(5) Adjusted EBITDAX is a non-GAAP financial measure. Our definition of Adjusted EBITDAX and a reconciliation of net income (loss) to Adjusted EBITDAX is provided under Prospectus Summary Non-GAAP Financial Measures and Reconciliations.

(6) Other capital expenditures consists primarily of capital drilling and lease acquisitions.

Table of Contents

MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

You should read the following discussion of our results of operations and financial condition with the Selected Historical Consolidated Financial Data and the historical financial statements and related notes included elsewhere in this prospectus. This discussion contains forward-looking statements and involves numerous risks and uncertainties, including, but not limited to, those described in the Risk Factors section of this prospectus. Actual results may differ materially from those contained in any forward-looking statements.

Overview

Crimson is an independent energy company engaged in the acquisition, exploitation, exploration and development of natural gas and crude oil properties. We have historically focused our operations in the onshore U.S. Gulf Coast and South Texas regions, which are generally characterized by high rates of return in known, prolific producing trends. We have recently expanded our strategic focus to include longer reserve life resource plays that we believe provide significant long-term growth potential in multiple formations.

In late 2008 and early 2009, we acquired approximately 12,000 net acres in East Texas where we completed our first well, the Kardell #1H, in October 2009. This well targeted the Haynesville Shale and initially produced 30.7 MMcfe/d, which we believe to be the highest publicly announced initial production rate to date in that formation. In addition to the Haynesville Shale, we believe this acreage is equally prospective in the Bossier Shale and James Lime formations where industry participants have drilled successful wells on adjacent acreage.

In 2007, we acquired approximately 2,800 net acres in South Texas, which we believe is prospective in the Austin Chalk and the Eagle Ford Shale. We drilled our first well on this acreage, the Dubose #1, during the fourth quarter of 2009, and we are preparing to complete the well in the Eagle Ford Shale.

We intend to grow reserves and production by developing our existing producing property base, developing our East Texas and South Texas resource potential, and pursuing opportunistic acquisitions in areas where we have specific operating expertise. We have developed a significant project inventory of over 800 drilling locations associated with our existing property base. Our technical team has a successful track record of adding reserves through the drillbit. Since January 2008, we have drilled 34 gross (15.2 net) wells with an overall success rate of 91% (excluding one well which has not yet been completed).

As of December 31, 2008, our estimated proved reserves, as prepared by our independent reserve engineering firm, Netherland, Sewell & Associates, Inc., were 131.9 Bcfe, consisting of 96.2 Bcf of natural gas and 6.0 MMBbl of crude oil, condensate and natural gas liquids. As of December 31, 2008, 73% of our proved reserves were natural gas, 69% were proved developed and 81% were attributed to wells and properties operated by us. From 2006 to 2008, we grew our estimated proved reserves from 46.4 Bcfe to 131.9 Bcfe. In addition, we grew our average daily production from 7.3 MMcfe/d for the year ended December 31, 2006 to 43.0 MMcfe/d for the nine months ended September 30, 2009. For the nine months ended September 30, 2009, we generated $55.2 million of Adjusted EBITDAX. Our definition of the non-GAAP financial measure of Adjusted EBITDAX and a reconciliation of net income (loss) to Adjusted EBITDAX are provided under Prospectus Summary Non-GAAP Financial Measures and Reconciliations. For the same period, our net income (loss) was $(16.8) million.

Recent Developments

East Texas Acreage Acquisition

In the second half of 2008 and early 2009, we obtained natural gas and crude oil leases from mineral interest owners covering approximately 17,000 gross (12,000 net) acres in the natural gas resource play in East Texas specifically in San Augustine and Sabine Counties. We commenced our first well (the Kardell #1H), in which we owned a 52% working interest, in this play in late June 2009 and completed that well in October 2009. The well had a measured depth of approximately 18,350 feet and was a successful test of the Haynesville Shale formation. The initial 24-hour production experienced from the Kardell #1H well in early November 2009 was 30.7 MMcfe/d (12.0 MMcfe/d net to our interest). We plan to continue to pursue an active drilling program in this area for the next several years, targeting primarily the Haynesville Shale, the Bossier Shale and the James Lime formations. We financed the acquisition of this acreage with cash flows from operations and from borrowings available under our revolving credit facility.

Smith Acquisition

In May 2008, we acquired four producing gas fields and undeveloped acreage in South Texas from Smith Production Inc. (Smith) for a purchase price of $65.0 million with an economic effective date of January 1, 2008. After adjustment for the estimated results of operations, and other typical purchase price adjustments of approximately $7.4 million for the period between the effective date and the closing date, the cash consideration was approximately $57.6 million. The assets acquired consist of a 25% non-operated working interest in the Samano Field located in Starr and Hidalgo Counties, a 100% operated working interest in the North Bob West Field in Zapata County and 100% operated working interests in the Brushy Creek and Hope Fields in DeWitt County. We acquired an interest in over 16,000 gross acres with these fields, most of which is held by production. Production from the acquired assets was averaging approximately 7 MMcfe/d at closing, which resulted in a 13% increase in our then current net daily production.

The adjusted price for this acreage, with adjustment of the reserves for approximately one Bcfe of production for the interim operations between the effective date and closing, represents a purchase cost of $2.82 per Mcfe for approximately 21 Bcfe of proved reserves and $8,300 per Mcfe of current average daily production. We financed this acquisition with cash flows from operations, proceeds from the sale of assets and from borrowings available under our revolving credit facility. For the year ended December 31, 2008, seven months of revenues and expenses, $11.7 million and $3.7 million, respectively, were included in our financial results of operations.

Southwest Louisiana Disposition

On November 24, 2009, we entered into a definitive agreement to sell operated and non-operated working interests in various producing wells, related production equipment and associated acreage primarily in Cameron, Calcasieu and Jefferson Davis parishes in Southwest Louisiana for an aggregate contract price of $10.2 million, subject to normal purchase price adjustments for environmental defects and oil and gas operations for the period between the effective date and the final closing date, and the assumption of all related asset retirement obligations, with an effective date of October 1, 2009. The assets include substantially all of our Southwest Louisiana properties, representing approximately 8.5 Bcfe of proved reserves at September 30, 2009, approximately $19.9 million in PV-10 as of September 30, 2009 and with average daily production of approximately 3.8 MMcfe/d for the nine months ended September 30, 2009, or approximately 9% of our total daily production for such period. We expect to use the proceeds from this sale to repay outstanding amounts under our revolving credit facility. We anticipate closing the transaction prior to 2010, subject to the prior satisfaction of customary closing conditions. We cannot assure you that all of the conditions to closing will be timely satisfied or satisfied at all.

Barnett Shale Disposition

In January 2008, we and our operator-partner entered into a series of agreements to sell our interests in wells and undeveloped acreage in the Fort Worth Barnett Shale Play in Johnson and Tarrant Counties, Texas to another industry participant active in that area. We owned a 12.5% non-operated working interest in the assets being sold and had

1.5 Bcfe in proved reserves at December 31, 2007.

The total consideration paid by the buyer was based on existing wells and undeveloped acreage owned by us and our partner at the time of the final closing. Our share of the consideration received was approximately $34.4 million. Proceeds received for our interest were primarily used to repay amounts outstanding under our revolving credit facility and to help finance our acquisition of the properties from Smith. Our net book value of the assets sold was $18.8 million, which resulted in a gain of $15.6 million.

Amendments to Revolving Credit Facility

Effective December 7, 2009, we entered into an amendment to our revolving credit facility that, among other things, amended certain of our financial covenants and our debt incurrence covenant and provided for redetermination of our borrowing base at January 1, 2010. See Liquidity and Capital Resources Capital resources Revolving Credit Facility.

Promissory Notes

On November 6, 2009, we issued an unsecured promissory note in the aggregate principal amount of $10.0 million to Wells Fargo Bank, National Association and an unsecured subordinated promissory note in the aggregate principal amount of $2.0 million to Oaktree Holdings, our majority stockholder. See Liquidity and Capital Resources Capital resources Promissory Notes.

Selected Factors That Affect Our Operating Results

Our revenue, cash flow from operations and future growth depend substantially upon the prices and demand for natural gas, crude oil and natural gas liquids, the quantity of our natural gas, oil and natural gas liquids production and changes in the fair value of derivative instruments we use to reduce the volatility of the prices we receive for our natural gas, oil and natural gas liquids production. Crude oil and natural gas prices have historically been volatile and may fluctuate widely in the future. Even relatively modest drops in prices can significantly affect our financial position and results of operations, the value of our reserves, the quantities of crude oil and gas that we can economically produce and our ability to access capital.

Commodity Prices. Commodity prices have been volatile over the past several years. Significant factors that will impact near-term commodity prices include the following:

- the domestic and foreign supply of and demand for crude oil and natural gas;
- the level of consumer product demand;
- weather conditions;
- political and economic conditions and events in foreign oil and gas producing countries, including those in the Middle East, South America and Russia;
- actions of the Organization of Petroleum Exporting Countries and state-controlled oil companies relating to oil price and production controls;
- technological advances affecting energy consumption and supply;
- domestic and foreign governmental regulations and taxation;
- the impact of energy conservation efforts;

the proximity, capacity, cost and availability of oil and gas pipelines and other transportation facilities to our production, and access to readily available alternatives in the event of disruptions in such pipelines or facilities; and

the price and availability of alternative fuels.

Prior to mid-2008, the oil and gas industry saw significant increases in activity resulting from high commodity prices for natural gas, crude oil and natural gas liquids. However, since mid-2008 commodity prices have declined significantly, which has adversely affected our results of operations. Supply and geopolitical uncertainties resulted in significant price volatility during 2008 with oil prices rising during the first half of the year to record levels before falling by approximately 68% during the second half of the year. Commodity prices, particularly gas prices, continued to decline during the first quarter of 2009. Spot prices for West Texas Intermediate West Texas Intermediate oil averaged $99.92/Bbl during 2008, with a low price of $31.41/Bbl in December 2008 and a high price of $145.29/Bbl in July 2008. During 2008, the gas market continued to be driven by high storage inventories and mild weather conditions across much of the country. Spot prices for Henry Hub gas averaged $8.89/MMbtu for the year, with a low price of $5.38/MMbtu in December 2008 and a high price of $13.31/MMbtu in July 2008. Spot prices for West Texas Intermediate oil averaged $68.14/Bbl and Henry Hub gas averaged $3.17/MMbtu during the third quarter of 2009. The NYMEX futures prices for oil and gas were $44.60/Bbl and $5.62/MMbtu at December 31, 2008 and $77.00/Bbl and $5.05/MMbtu at October 30, 2009. The current global recession has had a significant impact on commodity prices and our operations. If commodity prices remain depressed or decline further, this could negatively affect our ability to execute our growth strategy and generate cash flows. See Risk Factors Natural gas, crude oil and natural gas liquids prices are volatile, and a decline in prices can significantly affect our financial results and impede our growth and Recent changes in the financial and credit markets may impact economic growth and natural gas, crude oil and natural gas liquids prices may continue to be adversely affected by general economic conditions.

Reserves. As is typical for businesses engaged in the exploration and production of crude oil and natural gas, we face the challenge of natural production declines. As initial reservoir pressures are depleted, natural gas, crude oil and natural gas liquids production from a given well decreases. Thus, unless we conduct successful development, exploitation and exploration activities or acquire properties containing proved reserves, our proved reserves will decline as they are produced. Our future natural gas, crude oil and natural gas liquids reserves and production, and therefore our cash flow and results of operations, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves.

As of December 31, 2008, we had 131.9 Bcfe of estimated net proved reserves with an associated PV-10 of $291.0 million, representing an increase in reserves of 1.7 Bcfe from December 31, 2007, and an increase in reserves of 85.6 Bcfe from December 31, 2006, resulting primarily from our May 2007 acquisition of properties (STGC Properties) from EXCO Resources, Inc. (EXCO). As of September 30, 2009, we had 104.9 Bcfe of estimated net proved reserves with an associated PV-10 of $190.8 million, representing a decrease of 27.0 Bcfe from December 31, 2008. For a discussion of PV-10 and a reconciliation to Standardized Measure of Discounted Net Cash Flows, see Prospectus Summary Non-GAAP Financial Measures and Reconciliations. We believe that our proved reserves as of September 30, 2009 compared to December 31, 2008 have declined for a number of reasons, many of which are beyond our control. During the first nine months of 2009, declining commodity prices, reductions in production enhancing capital expenditures, as well as capital expenditures associated with our exploitation and development activities contributed to a decline in our proved reserves from December 31, 2008, as have normal production, operations, and certain property sales made throughout 2009. In addition, approximately 31% and 32% of our total estimated proved reserves at December 31, 2008 and September 30, 2009, respectively, were undeveloped. Estimates of net proved reserves are inherently imprecise. In addition, by their nature, estimates of undeveloped reserves are less certain than proved developed reserves. Recovery of such reserves will require significant capital expenditures and successful drilling operations. See Risk Factors Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions could materially reduce the estimated quantities and present value of our reserves. Our level of exploratory capital expenditures for the majority of 2009 was limited due to low commodity prices and limited access to the capital markets, and we deferred major capital allocation for drilling opportunities during the year.

44

The SEC has adopted new rules that are effective for fiscal years ending on or after December 31, 2009, which will impact how we estimate our proved reserves and related PV-10 and standardized measure of discounted future net cash flows. See Risk Factors Our estimates of proved reserves and related PV-10 and standardized measure of discounted future net cash flows, which are prepared and presented under existing SEC rules, may change materially as a result of new SEC rules that will go into effect for fiscal years ending on or after December 31, 2009.

Revenues and Production. Our revenues, net of the realized effects of our hedging instruments, decreased to $85.7 million in the nine months ended September 30, 2009 from $151.0 million in the nine months ended September 30, 2008, a decrease of 43.2%, due to an approximate 20% decrease in production and an approximate 29% decline in realized commodity prices. Revenues, net of the realized effects of our hedging instruments, decreased to $26.7 million for the three months ended September 30, 2009 from $53.1 million for the three months ended September 30, 2008, due to an approximate 29% decrease in production and an approximate 29% decline in realized commodity prices. In the nine month period ended September 30, 2009 our production was 11.7 Bcfe as compared to 14.6 Bcfe for the nine months ended September 30, 2008, or a decrease of 19.6%. This decrease was primarily due to natural field decline and limited production enhancing capital expenditure activity in the first nine months of 2009. On a daily basis, we produced an average of 43.0 MMcfe/d in the first nine months of 2009 compared to an average of 53.3 MMcfe/d in the first nine months of 2008. In the three month period ended September 30, 2009, our production decreased by 1.5 Bcfe, to 3.5 Bcfe from 5.0 Bcfe for the third quarter of 2009, or 30%, primarily due to natural field decline and limited production enhancing capital expenditure activity during 2009. On a daily basis, we produced an average of 38.3 MMcfe/d for the third quarter of 2009 compared to an average of 54.1 MMcfe/d for the third quarter of 2008.

For the year ended December 31, 2008, revenues, net of the realized effects of our hedging instruments, increased to $185.7 million from $109.2 million in 2007 and from $21.5 million in 2006. The increase in 2008 compared to 2007 was primarily due to increases in net realized commodity prices, the success experienced in our drilling program, the full-year effect of our May 2007 acquisition of the STGC Properties from EXCO and the seven-month effect of the May 2008 South Texas acquisition from Smith, offset by lost production and natural gas liquids not processed, due to Hurricanes Gustav and Ike. Production volumes increased to 19.2 Bcfe in 2008 from 13.2 Bcfe in 2007, representing a 6.0 Bcfe, or 45.2%, increase. Realized prices (net of hedges) were $9.66 per Mcfe in 2008 as compared to $8.25 in 2007. The increase in revenues in 2007 compared to 2006 was primarily due to our acquisition of the STGC Properties from EXCO in May of 2007. Production volumes increased approximately 399.2% during 2007 as compared to 2006 with average daily volumes of 36,264 Mcfe in 2007 compared to an average of 7,265 Mcfe in 2006.

Derivative Instruments. To achieve more predictable cash flow and to reduce our exposure to adverse fluctuations in commodity prices, we generally enter into derivative arrangements for a significant portion of our natural gas, crude oil and natural gas liquids production. See Quantitative and Qualitative Disclosures About Market Risk Commodity Price Risk and Derivative Instruments. While these derivative contracts will protect us when market prices are below our contract prices, they also prevent us from realizing an increase in cash flow when market prices are higher than our contract prices. We will sustain realized and unrealized losses to the extent our contract prices are lower than market prices and conversely, we will sustain realized and unrealized gains to the extent our contract prices are higher than market prices. Our derivatives contracts are not designated as accounting hedges and, as a result, gains or losses on derivatives contracts are recorded as an other expense. Internally, our management views the settlement of such derivatives contracts as adjustments to the price received for natural gas, crude oil and natural gas liquids production to determine realized prices.

Net of the realized effect of our hedging agreements, the price received for natural gas for the nine month period ended September 30, 2009 was $6.77 per Mcf, the price received for crude oil was $81.46 per Bbl, and the price received for natural gas liquids was $27.19 per Bbl, or $7.31 per Mcfe on a

45

combined equivalent basis. Before the realized effect of our hedges, the price received for natural gas for the nine month period ended September 30, 2009 was $3.92 per Mcf, the price received for crude oil was $52.80 per Bbl, and the price received for natural gas liquids was $27.19 per Bbl, or $4.68 per Mcfe on a combined equivalent basis.

We realized gains of $7.6 million on our crude oil hedges and $23.2 million on our natural gas hedges in the first nine months of 2009, compared to realized losses of $9.4 million for crude oil hedges and $3.8 million for natural gas hedges in the first nine months of 2008. During the nine month period ended September 30, 2009, we reported a $17.2 million non-cash unrealized loss on our derivatives positions compared to $1.7 million non-cash unrealized gain for the same period of 2008. We realized losses of $8.5 million on our crude oil hedges and $0.8 million on our natural gas hedges in 2008, compared to realized losses of $3.4 million for crude oil hedges and realized gains of $6.4 million for natural gas hedges in 2007, and a loss of $0.8 million for crude oil hedges and a realized gain of $0.2 million for natural gas hedges in 2006. During 2008, we reported a non-cash unrealized gain of $49.4 million compared with a non-cash unrealized loss of $18.2 million for 2007, and a $6.1 million non-cash unrealized gain for 2006. Unrealized gains or losses on derivative contracts represent the change in fair value of open derivative positions during the period. The change in fair value is principally measured based on period end prices as compared to the contract price. Future volatility in natural gas, crude oil and natural gas liquids prices could have an adverse effect on the operating results of our results of operations.

Operating Expenses. In evaluating our operations, we frequently monitor and assess our operating expenses, in terms of absolute dollars and on a per Mcfe basis. We believe that this measure allows us to better evaluate our operating efficiency and is used by us in reviewing the economic feasibility of a potential acquisition or development project. Operating expenses are the costs incurred in the operation of producing properties. Expenses for utilities, direct labor, water injection and disposal, production taxes and materials and supplies comprise the most significant portion of our operating expenses. A majority of our operating cost components are variable and increase or decrease as the level of production increases or decreases. Certain items, however, such as direct labor and materials and supplies, generally remain relatively fixed and do not fluctuate with changes in production volumes, but can fluctuate depending on activities performed during a specific period.

Our decrease in revenues for the nine months ended September 30, 2009 was offset by a decrease in our operating expenses, primarily due to the implementation of cost reduction initiatives in 2009 in response to a lower commodity price environment and lower production and realized prices in 2009. However, our exploration expense increased by $1.0 million, or 52.6%, from $1.9 million for the nine months ended September 30, 2008 to $2.9 million for the nine months ended September 30, 2009, primarily due to higher geological and geophysical costs, abandoned property, lease rentals and settled asset retirement costs incurred in the first nine months of 2009. Similarly, depreciation, depletion and amortization (DD&A) increased from $36.0 million for the nine months ended September 30, 2008 to $41.6 million for the nine months ended September 30, 2009, primarily due to a higher DD&A rate resulting from the effect of negative price-related revisions, partially offset by lower production in 2009.

The increase in our revenue for 2008 as compared to 2007 was offset by an increase of $47.8 million, or 66.2%, in our operating expenses, primarily due to increased costs and expenses resulting from the acquisition of properties from EXCO and Smith and higher production and realized prices Similarly, the increase in our revenue for 2007 as compared to 2006 was offset by an increase of $51.3 million, or 245.5%, in our operating expenses, primarily due to increased costs and expenses resulting from the acquisition of the STGC Properties from EXCO.

After application of approximately $117.6 million in net proceeds from this offering (estimated based upon the midpoint of the range of the offering price on the cover of this prospectus), we expect to have approximately $83.1 million of available borrowing capacity under our revolving credit facility to pursue our 2010 drilling program based upon $129.5 million outstanding under our revolving credit

facility as of December 4, 2009. See Liquidity and Capital Resources Capital resources Revolving Credit Facility. Our 2010 capital budget is approximately $56 million, exclusive of acquisitions, of which we expect to spend approximately 76% of our budget on our East Texas and South Texas resource plays and 24% on our existing producing assets. We plan to drill 12 gross (6.0 net) wells in 2010, including 7 gross (3.0 net) wells on our East Texas resource play acreage, one gross (0.4 net) well on our South Texas resource play acreage, and 4 gross (2.6 net) wells in Liberty County. The actual number of wells drilled and the amount of our 2010 capital expenditures will depend on market conditions, commodity prices, availability of capital and drilling and production results. We cannot assure you that our exploration and development activities will result in increases in our proved reserves.

Results of Operations

The following discussion is of our consolidated results of operations, financial condition and capital resources. You should read this discussion in conjunction with our Consolidated Financial Statements and the Notes thereto contained elsewhere in this prospectus. Comparative results of operations for the periods indicated are discussed below.

Nine Months Ended September 30, 2009 Compared to Nine Months Ended September 30, 2008

Revenues

	Nine Months Ended September 30,			
	2009	2008	Change	Percent Change
	(In millions, except percentages)			
Revenues:				
Natural gas sales	$ 55.1	$ 92.1	$ (37.0)	−40.2%
Crude oil sales	21.5	34.2	(12.7)	−37.1%
Natural gas liquids sales	9.1	24.7	(15.6)	−63.2%
Product revenues	$ 85.7	$ 151.0	$ (65.3)	−43.2%

Natural Gas, Crude Oil and Natural Gas Liquids Sales. Revenues from the sale of natural gas, crude oil and natural gas liquids, net of the realized effects of our hedging instruments, were $85.7 million for the first nine months of 2009 compared to $151.0 million for the first nine months of 2008 due to an approximate 20% decrease in production and an approximate 29% decline in realized commodity prices.

	Nine Months Ended September 30,			
	2009	2008	Change	Percent Change
Sales (production) volumes:				
Natural gas (Mcf)	8,142,588	9,752,667	(1,610,079)	−16.5%
Crude oil (Bbl)	264,170	385,458	(121,288)	−31.5%
Natural gas liquids (Bbl)	334,303	422,107	(87,804)	−20.8%
Natural gas equivalents (Mcfe)	11,733,426	14,598,057	(2,864,631)	−19.6%

Production was approximately 11.7 Bcfe for the first nine months of 2009 compared to approximately 14.6 Bcfe for the first nine months of 2008. On a daily basis, we produced an average of 43.0 MMcfe/d in the first nine months of 2009 compared to an average of 53.3 MMcfe/d in the first nine months of 2008. Production volumes decreased primarily due to natural field decline and limited production-enhancing capital expenditure activity in the first nine months of 2009.

	Nine Months Ended September 30,			
	2009	2008	Change	Percent Change
Average sales prices (before hedging):				
Natural gas (Mcf)	$ 3.92	$ 9.83	$ (5.91)	–60.1%
Crude oil (Bbl)	52.80	112.98	(60.18)	–53.3%
Natural gas liquids (Bbl)	27.19	58.49	(31.30)	–53.5%
Natural gas equivalents (Mcfe)	4.68	11.24	(6.56)	–58.4%
Average sales prices (after hedging):				
Natural gas (Mcf)	$ 6.77	$ 9.44	$ (2.67)	–28.3%
Crude oil (Bbl)	81.46	88.60	(7.14)	–8.1%
Natural gas liquids (Bbl)	27.19	58.49	(31.30)	–53.5%
Natural gas equivalents (Mcfe)	7.31	10.34	(3.03)	–29.3%

Natural gas, crude oil and natural gas liquids prices are reported net of the realized effect of our hedging agreements. We realized gains of $7.6 million on our crude oil hedges and $23.2 million on our natural gas hedges in the first nine months of 2009, compared to realized losses of $9.4 million for crude oil hedges and $3.8 million for natural gas hedges in the first nine months of 2008.

Costs and Expenses

	Nine Months Ended September 30,			
	2009	2008	Change	Percent Change
	(In millions, except percentages)			
Certain Operating Expenses:				
Lease operating expenses	$ 13.5	$ 15.4	$ (1.9)	–12.3%
Production and ad valorem taxes	6.1	14.4	(8.3)	–57.6%
Exploration expenses	2.9	1.9	1.0	52.6%
General and administrative(1)	11.5	13.3	(1.8)	–13.5%
Operating expenses (cash)	34.0	45.0	(11.0)	–24.4%
Depreciation, depletion and amortization	41.6	36.0	5.6	15.6%
Share-based compensation(1)	1.9	4.5	(2.6)	–57.8%
Certain operating expenses(2)	$ 77.5	$ 85.5	$ (8.0)	–9.4%

(1) Total general and administrative costs include share-based compensation on the Consolidated Statements of Operations.

(2) Exclusive of impairments and sales.

	Nine Months Ended September 30,			
	2009	2008	Change	Percent Change
	(In millions, except percentages)			
Selected Costs ($ per Mcfe):				
Lease operating expenses	$ 1.15	$ 1.05	$ 0.10	9.5%
Production and ad valorem taxes	0.52	0.98	(0.46)	–46.9%
Exploration expenses	0.24	0.13	0.11	84.6%
General and administrative[1]	0.98	0.91	0.07	7.7%
Operating expenses (cash)	2.89	3.07	(0.18)	–5.9%
Depreciation, depletion and amortization	3.55	2.47	1.08	43.7%
Share-based compensation[1]	0.16	0.31	(0.15)	–48.4%
Selected costs	$ 6.60	$ 5.85	$ 0.75	12.8%

(1) Total general and administrative costs include share-based compensation on the Consolidated Statements of Operations.

Lease Operating Expenses. Lease operating expenses for the first nine months of 2009 were $13.5 million, compared to $15.4 million in the first nine months of 2008, a decrease primarily due to the implementation of cost reduction initiatives in 2009 in response to the lower commodity price environment, offset by the incremental costs in 2009 related to producing properties acquired from Smith at the end of May 2008.

Production and Ad Valorem Tax Expenses. Production and ad valorem tax expenses for the first nine months of 2009 were $6.1 million, compared to $14.4 million for the first nine months of 2008, due to lower production and lower realized prices in 2009 and state tax credits net to us of $0.4 million as a result of our focus on maximizing allowable deductions and opportunities for tax relief for prior periods.

Exploration Expenses. Exploration expenses were $2.9 million in the first nine months of 2009 compared to $1.9 million for the first nine months of 2008. The increase in exploration expenses was primarily due to higher geological and geophysical costs, abandoned property, lease rentals and settled asset retirement costs incurred in the first nine months of 2009.

Depreciation, Depletion and Amortization. DD&A expense for the first nine months of 2009 was $41.6 million compared to $36.0 million for the first nine months of 2008, primarily due to a higher DD&A rate resulting from the effect of negative price related reserve revisions, partially offset by lower production in 2009.

Impairment of Oil and Gas Properties. Impairment expense for the first nine months of 2009 was zero compared to $25.8 million for the first nine months of 2008. The 2008 impairment relates primarily to our capital investment made in pursuing the Rodessa formation within the Madisonville Field. Negative performance-related reserve revisions, including the abandonment of the Rodessa formation in the Johnston 2U well, triggered an evaluation of the Madisonville Field for impairment purposes. Given the high original cost of drilling and developing the field and the high cost of producing and processing sour gas, combined with lower commodity prices, our evaluation resulted in the recorded costs of this field exceeding the estimated future undiscounted cash flow of the reserves as of the end of the third quarter 2008.

General and Administrative (G&A) Expenses. Total G&A expenses were $13.4 million for the first nine months of 2009 compared to $17.8 million for the first nine months of 2008, which includes non-cash stock expense of $1.9 million ($0.16 per Mcfe) and $4.5 million ($0.31 per Mcfe) for the first nine months of 2009 and 2008, respectively. The reduction in G&A expenses is primarily a result of implementing cost reduction initiatives during 2009.

Table of Contents

Gain on Sale of Assets. We sold minimal assets during the first nine months of 2009, while the gain on the sale of assets in the first nine months of 2008 was $15.3 million primarily due to the disposition of our interest in the Barnett Shale Play in January 2008.

Interest Expense. Interest expense was $16.3 million for the first nine months of 2009, compared to $15.9 million for the first nine months of 2008. Total interest expense increased primarily due to higher debt balances and higher interest rates on our second lien term loan agreement. Total interest expense capitalized for the first nine months of 2009 and 2008 was approximately $25,000 and $0.8 million, respectively.

Other Financing Costs. Other financing costs were $1.1 million for the first nine months of 2009 compared with $1.2 million for the first nine months of 2008. These expenses are comprised primarily of the amortization of capitalized costs associated with our credit agreements and to commitment fees related to the unused portion of the credit agreements.

Unrealized Gain (Loss) on Derivative Instruments. Unrealized gain or loss on derivative instruments is the change in the mark-to-market exposure under our commodity price hedging contracts and our interest rate swaps. This non-cash unrealized loss for the first nine months of 2009 was $17.2 million compared with a non-cash unrealized gain of $1.7 million for the first nine months of 2008. Unrealized gain or loss will vary period to period, and will be a function of hedges in place, the strike prices of those hedges and the forward curve pricing for the commodities and interest rates being hedged.

Income Taxes. Our net loss before taxes was $25.9 million for the first nine months of 2009 compared to net income before taxes of $40.4 million in the first nine months of 2008. After adjusting for permanent tax differences, we recorded income tax benefit of $9.1 million for the first nine months of 2009, compared to income tax expense of $15.1 million for the first nine months of 2008.

Dividends on Preferred Stock. Dividends on preferred stock were $3.4 million for the first nine months of 2009 compared with $3.2 million in the first nine months of 2008. Dividends in the first nine months of 2009 included approximately $3.3 million on the Series G Preferred Stock and $19,565 on the Series H Preferred Stock. Dividends in the first nine months of 2008 included $3.1 million on the Series G Preferred Stock, and $78,000 on the Series H Preferred Stock. Until such time as the board of directors declares and pays dividends on our Series G Preferred Stock, dividends shall continue to accumulate. Dividends on our Series H Preferred Stock are declared quarterly by our Board of Directors, and as such, are paid out in shares of our common stock during the following period.

Year Ended December 31, 2008 Compared to Year Ended December 31, 2007

Revenues

	Year Ended December 31,			
	2008	**2007**	**Change**	**Percent Change**
	(In millions, except percentages)			
Revenues:				
Natural gas sales	$ 116.4	$ 67.9	$ 48.5	71.4%
Crude oil sales	41.9	27.0	14.9	55.2%
Natural gas liquids sales	27.4	14.3	13.1	91.6%

Product revenues	$ 185.7	$ 109.2	$ 76.5	70.1%

Natural Gas, Crude Oil and Natural Gas Liquids Sales. Revenues from the sale of natural gas, crude oil and natural gas liquids, net of the realized effects of our hedging instruments, increased by 70.1%, to $185.7 million in 2008 compared to $109.2 million in 2007. The increase in net revenues was primarily due to increases in net realized commodity prices, the success experienced in our drilling program, the full-year effect of the May 2007 acquisition of the STGC Properties and the seven-month

Table of Contents

effect of the May 2008 South Texas acquisition from Smith, offset by lost production, and natural gas liquids not processed, due to Hurricanes Gustav and Ike.

	Year Ended December 31,			
	2008	2007	Change	Percent Change
Sales (production) volumes:				
Natural gas (Mcf)	13,135,509	9,067,777	4,067,732	44.9%
Crude oil (Bbl)	498,143	408,864	89,279	21.8%
Natural gas liquids (Bbl)	516,352	285,907	230,445	80.6%
Natural gas equivalents (Mcfe)	19,222,479	13,236,403	5,986,076	45.2%

For 2008, sales volumes increased approximately 45.2% compared to production in 2007. We had approximately 425,000 Mcfe of production deferred in the third and fourth quarters of 2008 due to Hurricanes Gustav and Ike. On a daily basis we produced an average of 52.5 MMcfe/d in 2008 compared to an average of 36.3 MMcfe/d in 2007.

	Year Ended December 31,			
	2008	2007	Change	Percent Change
Average sales prices (before hedging):				
Natural gas (Mcf)	$ 8.92	$ 6.78	$ 2.14	31.6%
Crude oil (Bbl)	101.13	74.38	26.75	36.0%
Natural gas liquids (Bbl)	53.07	49.92	3.15	6.3%
Natural gas equivalents (Mcfe)	10.14	8.02	2.12	26.4%
Average sales prices (after hedging):				
Natural gas (Mcf)	$ 8.86	$ 7.48	$ 1.38	18.4%
Crude oil (Bbl)	84.03	66.09	17.94	27.1%
Natural gas liquids (Bbl)	53.07	49.92	3.15	6.3%
Natural gas equivalents (Mcfe)	9.66	8.25	1.41	17.1%

Natural gas, crude oil and natural gas liquids prices are reported net of the realized effect of our hedging agreements. We realized losses of $8.5 million on our crude oil hedges and $0.8 million on our natural gas hedges in 2008, compared to realized losses of $3.4 million for crude oil hedges and realized gains of $6.4 million for natural gas hedges in 2007.

Operating Overhead and Other Income. Revenues from working interest partners increased to $1.1 million in 2008 compared to $0.4 million in 2007 due to the increase in administrative overhead fees charged to our partners on the operated acquired properties and the one-time catch up in the third quarter 2008 on overhead billings due to the increase in COPAS rates.

Table of Contents

Costs and Expenses

	Year Ended December 31,			
	2008	2007	Change	Percent Change
	(In millions, except percentages)			
Operating Expenses:				
Lease operating expenses	$ 20.8	$ 12.0	$ 8.8	73.3%
Production and ad valorem taxes	16.3	11.7	4.6	39.3%
Exploration expenses	10.0	3.2	6.8	212.5%
Depreciation, depletion and amortization	50.5	30.8	19.7	64.0%
General and administrative	22.4	14.5	7.9	54.5%
Operating expenses	$ 120.0	$ 72.2	$ 47.8	66.2%

	Year Ended December 31,			
	2008	2007	Change	Percent Change
Selected Costs ($ per Mcfe):				
Lease operating expenses	$ 1.08	$ 0.91	$ 0.17	18.7%
Production and ad valorem taxes	$ 0.85	$ 0.88	$ (0.03)	–3.4%
Exploration expenses	$ 0.52	$ 0.24	$ 0.28	116.7%
Depreciation, depletion and amortization	$ 2.63	$ 2.33	$ 0.30	12.9%
General and administrative expenses	$ 1.17	$ 1.10	$ 0.07	6.4%

Lease Operating Expenses. Lease operating expenses for 2008 were $20.8 million, compared to $12.0 million in 2007. The increase in lease operating expenses was primarily due to the addition of the STGC Properties and the South Texas properties from the Smith acquisition, increased workovers and general increases in the costs of goods and services in the industry.

Production and Ad Valorem Tax Expenses. Production and ad valorem tax expenses for 2008 were $16.3 million, compared to $11.7 million in 2007. The increase in production and ad valorem tax expenses was primarily due to higher production and realized prices in 2008.

Exploration Expenses. Total exploration expenses were $10.0 million in 2008 compared to $3.2 million in 2007. The significant increase in exploration expenses was primarily due to the release and abandonment of the undeveloped leasehold position that we acquired from Core Natural Resources in Culberson County, Texas in 2006 which resulted in leasehold abandonment cost of $7.1 million in 2008.

Depreciation, Depletion and Amortization. DD&A expense for 2008 was $50.5 million compared to $30.8 million in 2007, as a result of higher production volumes and a higher DD&A rate.

Impairment of Oil and Gas Properties. Impairment expense for 2008 was $36.0 million compared to $4.4 million in 2007. In December 2008, we recorded a non-cash impairment expense of $10.2 million, primarily related to our Grand

Lake Field in Southwest Louisiana, resulting from negative reserve revisions related to low commodity prices at year end. In September 2008, we recorded a non-cash impairment expense of $25.8 million related to the abandonment of the Rodessa formation development in our Madisonville Field in our Southeast Texas Region.

General and Administrative Expenses. Our G&A expenses were $22.4 million for 2008 compared to $14.5 million in 2007. Included in G&A expense is a non-cash stock expense of $5.4 million ($0.28 per Mcfe) and $4.7 million ($0.36 per Mcfe) for 2008 and 2007, respectively. G&A expenses increased primarily due to higher personnel costs, higher professional fees and higher office rent expense related to expanding our infrastructure.

Table of Contents

Gain on Sale of Assets. Gain on the sale of assets for 2008 was $15.2 million. The net gain on the sale of assets was primarily due to the disposition of our interest in the Barnett Shale Play in the first quarter 2008, which resulted in a gain of $15.6 million. The gain on the sale of assets in 2007 was $0.7 million.

Interest Expense. Interest expense was $21.1 million for 2008, up from $14.9 million in 2007. Total interest expense increased primarily as a result of higher outstanding loan balances on our credit agreements related to our acquisition and drilling activity. Total interest expense capitalized for 2008 and 2007 was $0.9 million and $1.3 million, respectively.

Other Financing Costs. Other financing costs were $1.5 million for 2008 compared with $1.3 million for 2007. These expenses are comprised primarily of the amortization of capitalized costs associated with our current and former credit agreements and to commitment fees related to the unused portion of the credit agreements.

Unrealized Gain (Loss) on Derivative Instruments. Unrealized gain or loss on derivative instruments is the change in the mark-to-market exposure under our commodity price hedging instruments and our interest rate swaps. This non-cash unrealized gain for 2008 was $49.4 million compared with a non-cash unrealized loss of $18.2 million for 2007. Unrealized gain or loss will vary period to period, and will be a function of the hedges in place, the strike prices of those hedges, and the forward curve pricing of the commodities and interest rates being hedged.

Income Taxes. Our net income before taxes was $72.9 million for 2008 compared to a net loss before taxes of $0.8 million in 2007. After adjusting for permanent tax differences, we recorded income tax expense of $26.7 million for 2008, of which $0.6 million was current tax expense and $26.1 million was deferred. The income tax benefit of $0.4 million for 2007 was all deferred.

Dividends on Preferred Stock. Dividends on preferred stock were $4.2 million for 2008 compared with $4.5 million in 2007. Dividends in 2008 included $4.1 million on the Series G Preferred Stock and $0.1 million on the Series H Preferred Stock. Dividends in 2007 included $4.3 million on the Series G Preferred Stock, $0.1 million on the Series H Preferred Stock and $0.1 million on the Series E Preferred Stock. All of the Series E Preferred Stock was converted to shares of our common stock in May 2007.

Year Ended December 31, 2007 Compared to Year Ended December 31, 2006

Revenues

	Year Ended December 31,			
	2007	2006	Change	Percent Change
	(In millions, except percentages)			
Revenues:				
Natural gas sales	$ 67.9	$ 10.6	$ 57.3	540.6%
Crude oil sales	27.0	10.9	16.1	147.7%
Natural gas liquids sales	14.3		14.3	%
Total operating revenues	$ 109.2	$ 21.5	$ 87.7	407.9%

Natural Gas, Crude Oil and Natural Gas Liquids Sales. Revenues from the sale of natural gas, crude oil and natural gas liquids, net of the realized effects of our hedging instruments, increased by 407.9%, to $109.2 million in 2007 compared to $21.5 million in 2006. The increase in net revenues was primarily due to the effect of the STGC Properties acquisition in May 2007, which significantly increased our production volumes.

Table of Contents

	Year Ended December 31,			
	2007	2006	Change	Percent Change
Sales (production) volumes:				
Natural gas (Mcf)	9,067,777	1,542,423	7,525,354	487.9%
Crude oil (Bbl)	408,864	184,881	223,983	121.1%
Natural gas liquids (Bbl)	285,907		285,907	%
Natural gas equivalents (Mcfe)	13,236,403	2,651,709	10,584,694	399.2%

For 2007, sales volumes increased approximately 400% compared to production in 2006. On a daily basis we produced an average of 36.3 MMcfe/d in 2007 compared to an average of 7.3 MMcfe/d in 2006.

	Year Ended December 31,			
	2007	2006	Change	Percent Change
Average sales prices (before hedging):				
Natural gas (Mcf)	$ 6.78	$ 6.76	$ 0.02	0.3%
Crude oil (Bbl)	74.38	63.29	11.09	17.5%
Natural gas liquids (Bbl)	49.92		49.92	%
Natural gas equivalents (Mcfe)	8.02	8.34	(0.32)	−3.8%
Average sales prices (after hedging):				
Natural gas (Mcf)	$ 7.48	$ 6.85	$ 0.63	9.2%
Crude oil (Bbl)	66.09	59.00	7.09	12.0%
Natural gas liquids (Bbl)	49.92		49.92	%
Natural gas equivalents (Mcfe)	8.25	8.10	0.15	1.9%

Natural gas, crude oil and natural gas liquids prices are reported net of the realized effect of our hedging agreements. No natural gas liquids were sold in 2006. We realized a loss of $3.4 million on our crude oil hedges and a gain of $6.4 million on our natural gas hedges in 2007 compared to a realized loss of $0.8 million for crude oil hedges and a realized gain of $0.2 million for natural gas hedges in 2006.

Operating Overhead and Other Income. Revenues from working interest partners increased to $0.4 million in 2007 compared to $0.2 million in 2006 due to the increase in administrative overhead fees charged to partners on the operated acquired STGC Properties.

Costs and Expenses

	Year Ended December 31,			
	2007	2006	Change	Percent Change
	(In millions, except percentages)			
Operating Expenses:				
Lease operating expenses	$ 12.0	$ 5.6	$ 6.4	114.3%

Production and ad valorem taxes	11.7	1.9	9.8	515.8%
Exploration expenses	3.2	0.7	2.5	357.1%
Depreciation, depletion and amortization	30.8	4.0	26.8	670.0%
General and administrative expenses	14.5	8.7	5.8	66.7%
Total operating expenses	$ 72.2	$ 20.9	$ 51.3	245.5%

	Year Ended December 31,			
	2007	2006	Change	Percent Change
Selected Costs ($ per Mcfe):				
Lease operating expenses	$ 0.91	$ 2.12	$ (1.21)	–57.1%
Production and ad valorem taxes	$ 0.88	$ 0.71	$ 0.17	23.9%
Exploration expenses	$ 0.24	$ 0.25	$ (0.01)	–4.0%
Depreciation, depletion and amortization	$ 2.33	$ 1.52	$ 0.81	53.3%
General and administrative expenses	$ 1.10	$ 3.29	$ (2.19)	–66.6%

Lease Operating Expenses. Lease operating expenses for 2007 were $12.0 million, compared to $5.6 million in 2006. The increase was primarily due to the addition of the STGC Properties.

Production and Ad Valorem Tax Expenses. Production and ad valorem tax expenses for 2007 were $11.7 million, compared to $1.9 million in 2006. The increase in production and ad valorem tax expenses was primarily due to the significant increase in production related to the acquisition of the STGC Properties.

Exploration Expenses. Total exploration expenses were $3.2 million in 2007 compared to $0.7 million in 2006. Exploration expenses increased primarily as a result of the acquisition of the STGC Properties.

Depreciation, Depletion and Amortization. DD&A expense for 2007 was $30.8 million compared to $4.0 million in 2006, as a result of our acquisition of the STGC Properties.

Impairment of Oil and Gas Properties. Impairment expense was $4.4 million in 2007, primarily related to impairments on our Turkey Creek and Huff McFaddin properties, and $3.1 million in 2006, primarily related to our Iola property. Declining performance and lower gas prices at year end were contributing factors in these property impairments.

General and Administrative Expenses. Our G&A expenses were $14.5 million in 2007 compared to $8.7 million in 2006. Included in G&A expense is non-cash stock expense of $4.7 million ($0.36 per Mcfe) and $3.8 million ($1.44 per Mcfe) for 2007 and 2006, respectively. The $5.8 million increase was primarily due to higher personnel costs, information technology costs, professional fees and office rent incurred in expanding our infrastructure after the acquisition of the STGC Properties.

*Interest Expe*nse. Interest expense was $14.9 million in 2007, up from $0.1 million in 2006. Total interest increased to $16.2 million for 2007 because of the higher outstanding balances on our credit agreements related to the STGC Properties acquisition. However, $1.3 million of that interest, which was related to our Madisonville/Rodessa Prospect, was capitalized in 2007.

Other Financing Costs. Other financing costs were $1.3 million in 2007 compared with $0.2 million in 2006. These expenses are comprised primarily of the amortization of capitalized costs associated with our current and former credit agreements and to commitment fees related to the unused portion of the credit agreements.

Unrealized Gain (Loss) on Derivative Instruments. Unrealized gain or loss on derivative instruments is the change in the mark-to-market exposure under our commodity price hedging instruments and our interest rate swap. This non-cash unrealized loss for 2007 was $18.2 million compared with a non-cash unrealized gain of $6.1 million for 2006. This amount will vary period to period and will be a function of the hedges in place, the strike prices of those hedges and the forward curve pricing of the commodities and interest rates being hedged.

Income Taxes. Our net loss before taxes was $0.8 million in 2007 compared to net income before taxes of $3.3 million in 2006. After adjusting for permanent tax differences, we recorded an income tax benefit of $0.4 million in 2007 and an income tax expense of $1.4 million in 2006. The income tax benefit/expense was all deferred for both years.

Table of Contents

*Dividends on Preferred Sto*ck. Dividends on preferred stock were $4.5 million in 2007 compared with $3.6 million for 2006. Dividends in 2007 included $4.3 million on the Series G Preferred Stock, $0.1 million on the Series H Preferred Stock and $0.1 million on the Series E Preferred Stock. Dividends in 2006 included $3.2 million on the Series G Preferred Stock, $0.1 million on the Series H Preferred Stock and $0.3 million on the Series E Preferred Stock. All of the Series E Preferred Stock was converted to common stock in May 2007.

Prior to the third quarter of 2007, we accumulated undeclared dividends on the Series G Preferred Stock, on a simple or non-compounded basis. During the third quarter, we were notified by the holder of a majority of our outstanding Series G Preferred Stock, Oaktree Holdings, that it believed that the provisions of the Certificate of Designations for the Series G Preferred Stock required compounding dividends. After reviewing its interpretation, and consulting with legal counsel, we and the Oaktree Holdings settled the dispute and agreed to calculate the accrued, undeclared and unpaid dividends on a compounded basis. This new basis for calculating the dividend accrual was documented in a clarification memo between the parties. The change in the method of calculating the accrued, undeclared dividend was a change in accounting estimate necessitated by the new information that became available with the written agreement between the parties in the settlement of the dispute. The net effect of the change in the accounting estimate was an increase of $0.7 million in preferred stock dividends in the Consolidated Statements of Operations for the year ended December 31, 2007, of which approximately $0.4 million was related to prior years, and $0.1 million and $0.2 million was related to the first and second quarters of 2007, respectively.

Critical Accounting Policies

The discussion and analysis of financial condition and results of our operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of these financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenue and expenses. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate such estimates and assumptions on a regular basis. We base our estimates on historical experience and various other 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. Actual results may differ from these estimates and assumptions used in preparation of our financial statements. Below, we have provided expanded discussion of the more significant accounting policies, estimates and judgments. We believe these accounting policies reflect the more significant estimates and assumptions used in preparation of our financial statements. Please read the notes to our audited consolidated financial statements included in this prospectus for a discussion of additional accounting policies and estimates made by management.

Successful Efforts Method

We use the successful efforts method of accounting for oil and gas producing activities. Costs to acquire mineral interests in oil and gas properties, to drill and equip exploratory wells that find proved reserves, and to drill and equip development wells are capitalized. Costs to drill exploratory wells that do not find proved reserves, delay rentals and geological and geophysical costs are expensed (except those costs used to determine a drill site location).

Depletion and Depreciation

We consider depletion and depreciation of oil and gas properties and related support equipment to be critical accounting estimates, based upon estimates of total recoverable natural gas, crude oil and natural gas liquids reserves. The estimates of natural gas, crude oil and natural gas liquids reserves utilized in the calculation of depletion and depreciation are estimated in accordance

with guidelines established by the Society of Petroleum Engineers, the SEC and the Financial Accounting Standards Board, which require that reserve estimates be prepared under existing economic and operating conditions with no provision for price and cost escalations over prices and costs existing at year end, except by contractual arrangements. We emphasize that reserve estimates are inherently imprecise. Accordingly, the estimates are expected to change as more current information becomes available. Our policy is to amortize capitalized natural gas, crude oil and natural gas liquids costs on the unit of production method, based upon these reserve estimates. It is reasonably possible that the estimates of future cash inflows, future gross revenues, the amount of natural gas, crude oil and natural gas liquids reserves, the remaining estimated lives of the oil and gas properties, or any combination of the above may be increased or reduced in the near term. If reduced, the carrying amount of capitalized oil and gas properties may be reduced materially in the near term.

Impairments

We assess all of our properties for possible impairment on an annual basis as a minimum, or as circumstances warrant, based on geological trend analysis, changes in proved reserves or relinquishment of acreage. When impairment occurs, the adjustment is recorded to accumulated depletion. See the discussion of impairment expenses in Management s Discussion and Analysis of Financial Condition and Results of Operations.

Asset Retirement Obligations

We recognize an estimated liability for the plugging and abandonment of our natural gas, crude oil and natural gas liquids wells and associated pipelines and equipment. The liability and the associated increase in the related long-lived asset are recorded in the period in which our asset retirement obligation, or ARO, is incurred. The liability is accreted to its present value each period and the capitalized cost is depreciated over the useful life of the related asset.

The estimated liability is based on historical experience in plugging and abandoning wells, estimated remaining lives of those wells based on reserves estimates and federal and state regulatory requirements. The liability is discounted using an assumed credit-adjusted risk-free rate.

Revisions to the liability could occur due to acquisitions, changes in estimates of plugging and abandonment costs, changes in the risk-free rate or remaining lives of the wells, or if federal or state regulators enact new plugging and abandonment requirements. At the time of abandonment, we recognize a gain or loss on abandonment to the extent that actual costs do not equal the estimated costs.

Derivative Instruments

At the end of each reporting period we record on our balance sheet the mark-to-market valuation of our derivative instruments. The estimated change in fair value of the derivatives is reported in Other Income and Expense as unrealized (gain) loss on derivative instruments.

Recent Accounting Pronouncements

SEC 33-8995/34-59192. In December 2008, the SEC adopted Release No. 33-8995/34-59192, Modernization of Oil and Gas Reporting (SEC 33-8995). This release amends the oil and gas reporting disclosures that exist in their current form in Regulation S-K and Regulation S-X under the Securities Act and the Exchange Act to provide investors with a more meaningful and comprehensive understanding of oil and gas reserves. The new rules include changes for the pricing used to estimate reserves; permitting disclosure of possible and probable reserves; permitting the inclusion of non-traditional resources in reserves and the use of new technology for determining reserves. SEC 33-8995 is effective for fiscal years ending on or after December 31, 2009. Early adoption is not permitted. We are currently evaluating the provisions of SEC 33-8995 and assessing the affect its adoption will have on our financial reporting disclosures.

Table of Contents

Contractual Obligations

The following table sets forth certain of our contractual obligations as of December 31, 2008:

	Long-Term Debt	Interest	Operating Leases	Asset Retirements	Executive Compensation	ACS Topic 740[(1)]
2009	$ 90,368	$ 14,848,716	$ 2,641,835	$ 1,659,371	$ 1,516,300	$
2010	17,352	14,848,716	1,820,471	1,031,755	1,516,300	
2011	126,673,074	5,279,543	1,437,749	1,953,292	710,000	
2012	150,000,000	3,864,088	1,419,933	438,172		
2013			1,419,933	393,668		
Thereafter			118,328	7,592,284		
Total	$ 276,780,794	$ 38,841,063	$ 8,858,249	$ 13,068,542	$ 3,742,600	$ 518,219

(1) FASB ACS Topic 740 (previously reported as FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes, An interpretation of FASB Statement No. 109). We cannot predict at this time when this obligation may be required to be paid, if at all.

As of September 30, 2009, there had been no significant changes to our contractual obligations from December 31, 2008.

Liquidity and Capital Resources

Our primary cash requirements are for capital expenditures, working capital, operating expenses, acquisitions and principal and interest payments on indebtedness. Our primary sources of liquidity are cash generated by operations, net of the realized effect of our hedging agreements, and amounts available to be drawn under our credit agreements. To the extent our cash requirements exceed our sources of liquidity, we will be required to fund our cash requirements through other means, such as through debt and equity financing activities and/or asset monetizations, and/or curtail capital expenditures.

Liquidity and cash flow

During the last year there has been volatility and disruption in the equity and debt markets. The volatility and disruptions have created conditions and/or business strategies that have adversely affected the financial condition of some of our lenders, the counterparties to our derivative instruments, our insurers and our crude oil and natural gas purchasers. While in recent months market conditions have stabilized, continued economic uncertainty may limit our ability to access the equity and debt markets. In addition, though a substantial portion of our production is hedged, we are still subject to commodity price risk and our liquidity may be adversely affected if commodity prices were to decline.

Our working capital deficit was $11.9 million as of September 30, 2009, compared to a working capital deficit of $37.6 million as of December 31, 2008. Current assets decreased $16.8 million, primarily due to the decrease in accounts receivable related to lower revenues and the decrease in the mark to market value of our current net derivatives. Current liabilities, primarily accounts payable and accrued liabilities, decreased $42.6 million due to our reduced capital expenditure activity for the nine months ended September 30, 2009 compared to the nine months ended September 30, 2008.

The table below summarizes certain measures of liquidity and capital expenditures, as well as our sources of capital from internal and external sources, for the past three years and the periods ended September 30, 2009 and September 30, 2008.

	Year Ended December 31, 2008	2007	2006	Nine Months Ended September 30, 2009	2008
			(In millions)		
Financial Measures					
Net cash provided by operating activities	$ 143.8	$ 69.6	$ 14.3	$ 2.8	$ 96.9
Net cash used in investing activities	(165.4)	(311.8)	(21.8)	(16.0)	(105.7)
Net cash provided by financing activities	16.7	247.0	7.0	13.3	14.3
Cash and cash equivalents		4.9			10.4
Capital expenditures, including acquisitions	200.3	312.5	21.8	16.1	140.6

Net cash provided by operating activities was $2.8 million for the nine months ended September 30, 2009, compared to $96.9 million for the nine months ended September 30, 2008, a change resulting primarily from the reduction in revenues, accounts payable and accrued liabilities as well as the change in the mark to market value of our derivatives during the nine months ended September 30, 2009. During the first nine months of 2009, the net cash provided by operating activities, before changes in working capital, was $36.4 million. Net cash provided by operating activities, before changes in working capital, was $89.3 million for the first nine months of 2008.

Net cash used in investing activities was $16.0 million for the nine months ended September 30, 2009 compared to $105.7 million for the nine months ended September 30, 2008. Net cash used for investing activities during the nine months ended September 30, 2009 were primarily capital expenditures for the development or maintenance of our proved reserves and the development of our Haynesville Shale natural gas resource play in East Texas. Net cash used in investing activities during the first nine months of 2008 was primarily for the Smith acquisition and capital expenditures for the development of our Southeast Texas properties, offset primarily by proceeds from the sale of our interest in the Barnett Shale Play.

Net cash provided by financing activities was $13.3 million for the first nine months of 2009 compared to $14.3 million for the first nine months of 2008. Net cash provided by financing activities during the first nine months of 2009 was primarily the result of net borrowings under our revolving credit facility to satisfy the fourth quarter 2008 balance in current liabilities related to our active drilling program in 2008. Net cash provided by financing activities for the first nine months of 2008 was primarily the result of borrowings on debt to fund the Smith acquisition and normal drilling expenditures, offset by repayments of debt from proceeds from the sale of our interest in the Barnett Shale Play and internally generated cash flow from operations.

Net cash provided by operating activities was $143.8 million for the year ended December 31, 2008, compared to $69.6 million for the year ended December 31, 2007, a change resulting primarily from an increase in revenues, accounts payable and accrued liabilities and a decrease in accounts receivable trade. Net cash provided by operating activities was $69.6 million for the year ended December 31, 2007, compared to $14.3 million for the year ended December 31, 2006, a change resulting primarily from an increase in revenues, accounts payable and accrued liabilities offset by an increase in accounts receivable trade.

Net cash used in investing activities was $165.4 million for the year ended December 31, 2008 compared to $311.8 million for the year ended December 31, 2007. Net cash used for investing activities during the year ended December 31, 2008 were primarily related to capital expenditures for the development or maintenance of our proved reserves, prospect acquisitions in Sabine and San Augustine counties in Texas, and the acquisition of properties in South Texas from Smith, offset in part by the sale of properties in the Barnett Shale. Net cash used in investing activities during the year ended December 31, 2007, related primarily to the acquisition of the STGC Properties and capital expenditures for the development or maintenance of our proved reserves.

Net cash provided by financing activities was $16.7 million for the year ended December 31, 2008 compared to $247.0 million for the year ended December 31, 2007. Net cash provided by financing activities during the year ended December 31, 2008 was the result of net borrowings under our revolving credit facility primarily used for our capital expenditures for the development of new reserves, for prospect acquisitions and to satisfy the South Texas acquisition from Smith, offset by cash proceeds received from the sale of properties in the Barnett Shale. Net cash provided by financing activities during the year ended December 31, 2007 was primarily the result of net cash provided by our second lien credit agreement to satisfy the acquisition of the STGC Properties and net borrowings under our revolving credit facility for our capital expenditures.

Capital resources

Revolving Credit Facility. On May 8, 2007, we entered into a revolving credit facility with Wells Fargo Bank, National Association, as agent, and the lenders party thereto, which amended and restated our revolving credit facility dated as of July 15, 2005, as amended. On May 8, 2007, we borrowed $122.7 million pursuant to this revolving credit facility to pay the consideration for the acquisition of the STGC Properties and to refinance certain of our existing indebtedness. On May 31, 2007, we amended and restated this facility (as amended and restated, our revolving credit facility). Our revolving credit facility provides for aggregate borrowings of up to $400.0 million for acquisitions of crude oil and gas properties and for general corporate cash requirements.

Borrowings under our revolving credit facility are subject to a borrowing base limitation based on our proved crude oil and natural gas reserves. The borrowing base under this facility is currently set at $140.0 million, but, subject to the completion of this offering, will decrease to $105.0 million at January 1, 2010. The next borrowing base re-determination under our revolving credit facility after January 1, 2010 is scheduled for May 1, 2010 and is subject to semi-annual redeterminations, although our lenders may elect to make one additional redetermination between scheduled redetermination dates. As of November 6, 2009, we had $129.5 million in aggregate indebtedness outstanding under our revolving credit facility. Our revolving credit facility has a term of four years, and all principal amounts, together with all accrued and unpaid interest, will be due and payable in full on May 8, 2011. Our revolving credit facility also provides for the issuance of letters-of-credit up to a $5.0 million sub-limit.

Advances under our revolving credit facility are in the form of either base rate loans or LIBOR loans. The interest rate on the base rate loans fluctuates based upon the higher of the lender s prime rate and the Federal Funds rate plus a margin of 0.50%. The interest rate on the LIBOR loans fluctuates based upon the rate at which Eurodollar deposits in the LIBOR are quoted for the maturity selected. Pursuant to an amendment to our revolving credit facility, dated July 31, 2009, the applicable margin was increased from between 1.25% and 2.00% to between 2.75% and 3.50%, for LIBOR loans, and from zero and 0.50% to between 1.50% and 2.00%, for base rate loans. The specific interest margin applicable is determined by, in each case, the percent of the borrowing base utilized at the time of the credit extension. LIBOR loans of one, two, three and six months may be selected. Pursuant to that same amendment, the commitment fee payable on the unused portion of our borrowing base was increased from 0.375% to 0.50%, which fee accrues and is payable quarterly in arrears.

On November 6, 2009, we entered into a second and a third amendment to our revolving credit facility. These amendments provided, among other things, for (i) a change in the voting percentages required for certain amendments or waivers from 50.1% to 60%, and (ii) a waiver of the current ratio and the leverage ratio for the quarter ended September 30, 2009.

Effective December 7, 2009, we entered into a fourth amendment to our revolving credit facility. This amendment provides, among other things, that, subject to the closing of this offering, (i) the ratio of our total debt to Adjusted EBITDAX for any four trailing fiscal quarters may not be greater than 3.50x as of the end of any fiscal quarter ending on or prior to December 31, 2010, and 3.25x as of the end of any fiscal quarter ending thereafter, and (ii) the ratio of

Adjusted EBITDAX to

cash interest expense for any four trailing fiscal quarters may not be less than 2.25x as of the end of any fiscal quarter ending on or prior to December 31, 2010, and 2.75x as of the end of any fiscal quarter ending thereafter. In addition, this amendment also provides that, subject to the closing of this offering, the borrowing base under our revolving credit facility will be redetermined to be $105.0 million at January 1, 2010 and that we may issue up to $200 million in senior unsecured notes. Any such issuance of senior unsecured notes will reduce our borrowing base by 25% of the net proceeds from such issuance in excess of $150 million.

Second Lien Term Loan Agreement. On May 8, 2007, we entered into a five-year second lien term loan agreement with Credit Suisse, as agent, and the lender party thereto which provided for term loans, made to us in a single draw, in an aggregate principal amount of $150.0 million (our second lien term loan agreement). On May 8, 2007, we borrowed $150.0 million pursuant to this second lien term loan agreement to pay the consideration for the acquisition of the STGC Properties and to refinance certain existing indebtedness. Our second lien term loan agreement replaced our then existing $150.0 million subordinate credit facility, which was paid off in full and terminated at closing. Our second lien term loan agreement matures on May 8, 2012. Loans under the second lien term loan agreement, as it has been amended, bear interest at a per annum rate equal to LIBOR plus 5.75%, in the case of LIBOR loans, or the base rate plus 4.75%, in the case of base rate loans. Eurodollar loans of one, two, three and six months may be selected.

On May 13, 2009, we entered into a second amendment to our second lien term loan agreement (including with an affiliate of Oaktree Holdings), which, among other things, (i) modified the leverage ratio covenant to be no greater than the leverage ratio under our revolving credit facility plus 0.25, (ii) modified the PV-10 ratio covenant to not less than 1.2x beginning with the fiscal quarter ended June 30, 2009, to not be less than 1.25x, beginning with the fiscal quarter ending December 31, 2009, and to not be less than 1.5x beginning with the fiscal quarter ending December 31, 2010 and thereafter, (iii) increased the applicable margin to 8.0% for loans bearing interest at LIBOR and 7.0% for loans bearing interest at the alternate base rate, unless we meet certain leverage and PV-10 ratios, in which case the applicable margin will be 7.0% and 6.0%, respectively, (iv) set a minimum LIBOR of 3.0%, and (v) included certain fee acreage in calculations of our borrowing base after we have granted a lien on such fee acreage.

On November 6, 2009, we entered into a third amendment and waiver to our second lien term loan agreement with lenders holding a majority of the then outstanding term loans under such agreement, which included an affiliate of Oaktree Holdings. The amendment and waiver provided, among other things, for a waiver of the leverage ratio covenant under that agreement for the quarter ended September 30, 2009.

At September 30, 2009, we were in compliance with the covenants under our revolving credit facility and second lien term loan agreement, with the exception of the current ratio under our revolving credit facility and the leverage ratio under both of these credit agreements. We obtained waivers of such noncompliance from our lenders under both of these credit agreements for the quarter ended September 30, 2009, and effective December 7, 2009 amended the covenants under our revolving credit facility as discussed above under Revolving Credit Facility.

Our revolving credit facility and our second lien term loan agreement are secured by liens on substantially all of our assets, including the capital stock of our subsidiaries. The liens securing the obligations under our second lien term loan agreement are junior to those under our revolving credit facility. Unpaid interest is payable under our credit agreements as borrowings mature and renew.

In connection with the credit agreements, we utilize financial commodity price hedge instruments to minimize exposure to declining prices on our crude oil and natural gas liquids production. As of September 30, 2009, we had 13.9 MMcfe of equivalent production hedged representing 2.3 MMcfe, 7.6 MMcfe and 3.9 MMcfe of hedges in place in 2009, 2010 and 2011, respectively. Of the hedges in place through 2011, approximately 80% of the hedges are natural gas hedges and 20% are crude oil hedges. We used a series of swaps and costless collars to accomplish

61

the hedging requirements. We also constructively fixed the base LIBOR on $200.0 million of our variable rate debt by entering into interest rate swaps at a weighted average swap price of 2.61%.

At September 30, 2009, we had $141.5 million outstanding under our revolving credit facility and $150.0 million outstanding under our second lien term loan agreement.

Promissory Notes. On November 6, 2009, we issued an unsecured promissory note in aggregate principal of $10.0 million to Wells Fargo Bank, National Association, the administrative agent and a lender under our revolving credit facility. All of the proceeds of this promissory note were used to repay indebtedness outstanding under our revolving credit facility. The indebtedness under this promissory note bears interest at a per annum rate equal to two-month LIBOR plus 2.0% and matures on January 15, 2010; provided that upon an event of default resulting from the failure to make any payment of principal or interest under this promissory note, the interest rate per annum will increase to an amount equal to the lesser of the maximum rate of interest that may be charged under applicable law and LIBOR plus 4.0% or, if the promissory note has been assigned to any person other than any affiliate of Wells Fargo Bank, National Association, LIBOR plus 15.0%. The indebtedness under this promissory note may be prepaid, from time to time, in whole or in part, without premium or penalty. Wells Fargo Bank, National Association as payee, may assign this promissory note at any time provided that the assignee expressly agrees to subordinate its right to payment under this promissory note to all obligations under our revolving credit facility. In addition to any other rights and remedies Wells Fargo Bank, National Association, as payee, may have under this promissory note, upon the occurrence and continuation of an event of default, Wells Fargo Bank, National Association may cause this promissory note to be assigned to Oaktree Holdings in full. As support for this contingent obligation to purchase this promissory note, Oaktree Holdings has deposited $10.0 million in escrow for the benefit of Wells Fargo Bank, National Association. Upon an event of default under this promissory note, on January 15, 2010, Wells Fargo Bank, National Association may, at its option, cause the note to be assigned to Oaktree Holdings and can draw upon the funds held in escrow as payment for such assignment.

As consideration for Oaktree Holdings agreement to deposit $10.0 million in escrow as described above, we issued an unsecured subordinated promissory note on November 6, 2009 in aggregate principal amount of $2.0 million to Oaktree Holdings. The indebtedness under the promissory note bears interest at a per annum rate equal to 8.0% and matures on the later of (i) November 8, 2012 and (ii) the date six months after payment in full in cash of all Obligations (as such term is defined under our credit agreements), and the termination of all commitments to extend credit under our credit facilities. The promissory note is subordinated in right of payment to the prior payment in full in cash of all obligations under our credit agreements.

Covenant compliance

Our existing credit agreements contain certain financial covenants that require us to maintain a maximum level of total debt to Adjusted EBITDAX and a minimum adjusted interest coverage ratio, in each case, on a trailing four-quarter basis. Our compliance with these covenants is tested each quarter. We believe our credit agreements are material agreements and that these financial covenants are material terms of those agreements. Non-compliance with these covenants could result in a default, and an acceleration in the repayment of amounts outstanding, under our credit agreements. If an event of default occurs and is continuing under either credit agreement, we would be precluded from, among other things, paying dividends on our common stock or making additional borrowings. As a result, we believe the information presented below regarding these financial covenants is material to investors understanding of our results of operations and financial condition. See Liquidity and Capital Resources Capital resources for a more detailed description of terms and provisions of our credit agreements.

At September 30, 2009, the financial covenants contained in our credit agreements included (a) with respect to our revolving credit facility, maintaining (i) a ratio of current assets to current

liabilities of at least 1.0 to 1.0, (ii) an interest coverage ratio of Adjusted EBITDAX (defined as EBITDAX in such agreement) to cash interest expense of not less than 3.0 to 1.0 and (iii) a ratio of total debt to Adjusted EBITDAX of not greater than 2.75 to 1.00 and (b) with respect to our second lien term loan agreement, maintaining (i) a minimum leverage ratio of total debt to Adjusted EBITDAX of not greater than the leverage ratio under our revolving credit facility plus 0.25 and (ii) a ratio of the PV-10 of our oil and gas reserves to total net debt, or PV-10 Ratio (which ratio is calculated semi-annually based on the latest reserve report), of at least 1.5x. Effective December 7, 2009, we entered into an amendment to our revolving credit facility that, among other things, amended certain of our financial covenants and our debt incurrence covenant and provided for redetermination of our borrowing base at January 1, 2010. See Liquidity and Capital Resources Capital resources Revolving Credit Facility.

As of September 30, 2009, our ratio of current assets to current liabilities was 0.71. For the four quarters ended September 30, 2009, our ratio of total debt to Adjusted EBITDAX was 3.68; our ratio of interest expense to Adjusted EBITDAX was 0.27; and our PV-10 Ratio was 3.68.

We believe the presentation of Adjusted EBITDAX is appropriate to provide additional information to investors to demonstrate our ability to comply with the financial covenants to which we are and expect to be subject. For a reconciliation of net income (loss) to Adjusted EBITDAX, see Prospectus Summary Non-GAAP Financial Measures and Reconciliations. The calculation of Adjusted EBITDAX in this prospectus is in accordance with the definitions contained in our credit agreements.

Future capital requirements

Our future natural gas, crude oil and natural gas liquids reserves and production, and therefore our cash flow and results of operations, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We intend to grow our reserves and production by further exploiting our existing property base, through drilling opportunities identified in our new resource plays in East and South Texas and in our conventional inventory. We expect to focus much of our drilling activity over the next several years on continued development of our East Texas and South Texas resource plays while we continue the development and exploitation of our core legacy properties in the South Texas and Gulf Coast areas. We anticipate that acquisitions, including of undeveloped leasehold interests, will continue to play a significant role in our business strategy as those opportunities periodically arise from time to time. While there are currently no unannounced agreements for the acquisition of any material businesses or assets, such transactions can be effected quickly and could occur at any time.

We believe that the proceeds from this offering and our internally generated cash flow combined with access to our revolving credit facility will be sufficient to meet the liquidity requirements necessary to fund our daily operations, planned capital development and execute on our growth strategy and debt service requirements for the next 12 months. Our ability to execute on our growth strategy will be determined, in large part, by the availability of debt and equity capital at that time, and we continuously evaluate our financing opportunities. Any decision regarding a financing transaction, and our ability to complete such a transaction, will depend on prevailing market conditions and other factors. Our ability to continue to meet our liquidity requirements and execute on our growth strategy can be impacted by economic conditions outside of our control, such as the recent disruption in the capital and credit markets, as well as continued commodity price volatility, which could, among other things, lead to a decline in the borrowing base under our revolving credit facility in connection with a borrowing base redetermination. In such case, we may be required to seek other sources of capital earlier than anticipated, although the restrictions in our credit agreements may impair our ability to access other sources of capital, and access to additional capital may not be available on terms acceptable to us or at all. See Risk Factors Recent market events and conditions, including disruptions in the U.S. and international credit markets and other financial systems and the deterioration of the U.S. and global economic conditions, could, among other things, impede access to

Table of Contents

capital or increase the cost of capital, which would have an adverse effect on our ability to fund our working capital and other capital requirements, Risk Factors Our development and exploration operations, including on our East Texas resource play acreage, require substantial capital, and we may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a loss of properties and a decline in our natural gas, crude oil and natural gas liquids reserves and Management s Discussion and Analysis of Financial Condition and Results of Operations.

Due to low commodity prices and limited access to capital markets during 2009, our capital expenditure strategy for 2009 was to keep expenditures within internally generated cash flow and to reduce debt. For the nine months ended September 30, 2009, we made capital expenditures of $16.5 million, primarily for our Liberty County and East Texas leasing and drilling programs. We currently anticipate capital expenditures to be no more than $20 million in 2009. Our 2010 capital budget is approximately $56 million, exclusive of acquisitions, of which we expect to spend approximately 76% of our budget on our East Texas and South Texas resource plays and 24% on our existing producing assets. We plan to drill 12 gross (6.0 net) wells in 2010, including 7 gross (3.0 net) wells on our East Texas resource play acreage, one gross (0.4 net) wells on our South Texas resource play acreage, and 4 gross (2.6 net) wells in Liberty County. The actual number of wells drilled and the amount of our 2010 capital expenditures will depend on market conditions, availability of capital and drilling and production results. The following table sets forth our estimated capital budget for 2010:

2010E Capital Budget	**Southeast Texas**	**South Texas**	**Southwest Louisiana**	**Colorado and Other**	**East Texas**	**Non-Operated**	**Land/ Geological and Geophysical**	**Total**
Capital Expenditures (in millions)	$ 13	$ 3	$	$	$ 36	$	$ 4	$ 56
Gross Wells	4	1			7			12
Net Wells	2.6	0.4			3.0			6.0

64

Table of Contents

Inflation and Changes in Prices

While the general level of inflation affects certain costs associated with the petroleum industry, factors unique to the industry result in independent price fluctuations. Such price changes have had, and will continue to have a material effect on our operations; however, we cannot predict these fluctuations.

The following table indicates the average quarterly crude oil, natural gas and natural gas liquids prices received over the last three years. Average prices per Mcf equivalent, computed by converting crude oil production to natural gas equivalents at the rate of 6 Mcf per barrel, indicate the composite impact of changes in crude oil and natural gas prices.

	Average Prices[1]			
	Natural Gas (per Mcf)	Crude Oil (per Bbl)	Natural Gas Liquids[2] (per Bbl)	Per Equivalent Mcf
2009 year to date	$ 6.77	$ 81.46	$ 27.19	$ 7.31
2008				
First	$ 8.39	$ 78.62	$ 57.18	$ 9.39
Second	10.23	95.52	55.73	10.94
Third	9.68	92.54	63.49	10.67
Fourth	7.20	68.42	28.84	7.52
2007				
First	$ 7.07	$ 60.28	$	$ 8.33
Second	7.64	62.66	43.29	8.09
Third	7.60	66.47	45.17	8.18
Fourth	7.28	69.41	55.19	8.42
2006				
First	$ 7.71	$ 58.11	$	$ 8.63
Second	6.61	60.48		8.09
Third	6.72	60.85		8.07
Fourth	6.56	56.71		7.71

(1) Average sales price are shown net of the settled amounts of our natural gas and crude oil hedge contracts.

(2) Natural gas liquids became a significant addition to our reserves since the acquisition of the STGC Properties in May 2007.

Quantitative and Qualitative Disclosures About Market Risk

The following market rate disclosures should be read in conjunction with the quantitative disclosures about market risk contained in this prospectus, as well as with the consolidated financial statements and notes thereto. All of our derivative financial instruments are for purposes other than trading. We only enter into derivative financial instruments in conjunction with our crude oil and natural gas price hedging activities. Hypothetical changes in interest rates and prices chosen for the following stimulated sensitivity effects are considered to be reasonably possible near-term changes generally based on consideration of past fluctuations for each risk category. It is not possible to accurately predict future changes in interest rates and product prices. Accordingly, these hypothetical changes may not be an indicator of probable future fluctuations.

Table of Contents

Interest Rate Risk

We are exposed to interest rate risk on debt with variable interest rates. To manage this risk and reduce our sensitivity to volatile interest rates, we have entered into interest rate swap agreements with a total notional amount of $200.0 million related to our indebtedness. However, these interest rate swap agreements limit the benefit of decreases in interest rates. Moreover, these swap agreements apply only to a portion of our debt and provide only partial protection against increases in interest rates. Under these agreements, we receive interest at a floating rate equal to one-month LIBOR and pay interest at a fixed rate of 1.50% for $50.0 million and pay interest at 2.90% for $150.0 million, effectively setting our base LIBOR rate at 2.6%. As of September 30, 2009, the interest rate swaps had an estimated net fair value liability of $5.2 million. Assuming our current level of borrowings and considering the effect of the interest rate swap agreements, a 100 basis point increase in the interest rate we pay under our revolving credit facility would not have had a material impact on our interest expense for the nine months ended September 30, 2009.

Commodity Price Risk

In the past we have entered into, and may in the future enter into, certain derivative arrangements with respect to portions of our natural gas, crude oil and natural gas liquids production to reduce our sensitivity to volatile commodity prices. During 2009, 2008 and 2007, we entered into price swaps and put agreements with financial institutions. We believe that these derivative arrangements, although not free of risk, allow us to achieve a more predictable cash flow and to reduce exposure to price fluctuations. However, derivative arrangements limit the benefit to us of increases in the prices of crude oil and natural gas sales. Moreover, our derivative arrangements apply only to a portion of our production and provide only partial price protection against declines in price. Such arrangements may expose us to risk of financial loss in certain circumstances. We expect that the monthly volume of derivative arrangements will vary from time to time. We continuously reevaluate our price hedging program in light of increases in production, market conditions, commodity price forecasts, and capital spending and debt service requirements.

Counterparty Risk

We have exposure to financial institutions in the form of derivative transactions in connection with our hedges. These transactions are with counterparties in the financial services industry, specifically with members of our bank group. These transactions could expose us to credit risk in the event of default of our counterparties. We believe our counterparty risk related to our derivatives is low because of the offsetting relationships we have with each of our counterparties. In addition, we also have exposure to financial institutions within our credit agreements. If any lender under our revolving credit agreement is unable to fund its commitment, our liquidity could be reduced by an amount up to the aggregate amount of such lender s commitment under the revolving credit agreement.

Derivative Instruments

At the end of each reporting period we record on our balance sheet the mark-to-market valuation of our derivative instruments. We recorded a net asset for derivative instruments of $34.2 million and a net liability of $15.3 million at December 31, 2008 and 2007, respectively. As a result of these agreements, we recorded a non-cash unrealized gain, for unsettled contracts, of $49.4 million, a non-cash unrealized loss of $18.2 million and a non-cash unrealized gain of $6.1 million for the years ended December 31, 2008, 2007 and 2006, respectively. As of September 30, 2009, these derivative instruments had an estimated net fair value asset of $16.9 million. The estimated change in fair value of the derivatives is reported in Other Income (Expense) as unrealized gain (loss) on derivative instruments.

For natural gas, crude oil and natural gas liquids derivatives settled during 2008, we realized losses, reflected in operating revenues, of $9.3 million for the year ended December 31, 2008. For natural

Table of Contents

gas, crude oil and natural gas liquids derivatives settled during 2007, we realized gains of $3.0 million for the year ended December 31, 2007 and a non-cash unrealized gain of $6.1 million for the twelve months ended December 31, 2006. For natural gas, crude oil natural gas liquids derivatives settled during 2006, we realized losses, reflected in operating revenues of $0.6 million for the twelve months ended December 31, 2006. For interest rate swaps, we realized losses, included in interest expense, of $4.0 million for the twelve months ended December 31, 2008. We realized gains, included in interest expense, of $0.2 million from interest rate swaps for the twelve months ended December 31, 2007.

For natural gas, crude oil and natural gas liquids derivatives settled during the nine months ended September 30, 2009 and 2008, reflected in operating revenues, we realized gains of $30.8 million and losses of $13.2 million, respectively. We also recorded a non-cash unrealized loss, reflected in other income (expense), of $17.7 million for the nine months ended September 30, 2009 and a non-cash unrealized gain of $0.8 million for the nine months ended September 30, 2008. For interest rate swaps, we realized a loss, included in interest expense, of $3.2 million and $2.8 million for the nine months ended September 30, 2009 and 2008, respectively. We also recorded for interest rate swaps non-cash gains, reflected in other income (expense), of $0.4 million and $0.9 million for the nine months ended September 30, 2009 and 2008, respectively.

The following commodity derivatives contracts were in place at September 30, 2009.

Crude Oil		**Volume/Month**		**Price/Unit**
Oct 2009-Dec 2009	Swap	5,200 Bbls	$	74.20
Oct 2009-Dec 2009	Collar	12,800 Bbls	$	66.55-$71.40
Oct 2009-Dec 2009	Collar	10,733 Bbls(1)	$	115.00-$171.50
Jan 2010-Dec 2010	Swap	4,250 Bbls	$	72.32
Jan 2010-Dec 2010	Collar	9,000 Bbls	$	65.28-$70.60
Jan 2010-Dec 2010	Collar	7,604 Bbls(1)	$	110.00-$181.25
Jan 2011-Dec 2011	Swap	3,300 Bbls	$	70.74
Jan 2011-Dec 2011	Collar	7,000 Bbls	$	64.50-$69.50

Natural Gas				
Oct 2009-Dec 2009	Swap	36,000 MMbtu	$	8.32
Oct 2009-Dec 2009	Collar	475,000 MMbtu	$	7.90-$9.45
Oct 2009-Dec 2009	Collar	101,200 MMbtu(1)	$	9.50-$18.70
Jan 2010-Jun 2010	Swap	45,833 MMbtu(1)	$	6.25(2)
Jan 2010-Dec 2010	Swap	29,000 MMbtu	$	7.88
Jan 2010-Dec 2010	Collar	351,000 MMbtu	$	7.57-$9.05
Jan 2010-Dec 2010	Collar	85,167 MMbtu(1)	$	9.00-$15.25
Jan 2011-Dec 2011	Collar	266,000 MMbtu	$	7.32-$8.70

Interest Rate		**Notional Amount**	**Fixed LIBOR Rate**
Oct 2009-Dec 2010	Swap	$ 50,000,000	1.50%
Oct 2009-May 2011	Swap	$150,000,000	2.90%

(1) Average volume per month for the remaining contract term.

(2) Average price for the contract term.

The total net fair value asset for derivative instruments at September 30, 2009 was approximately $16.9 million and at December 31, 2008 was approximately $34.2 million, which are shown as derivative instruments on the balance sheet.

BUSINESS

Company Overview

Crimson is an independent energy company engaged in the acquisition, exploitation, exploration and development of natural gas and crude oil properties. We have historically focused our operations in the onshore U.S. Gulf Coast and South Texas regions, which are generally characterized by high rates of return in known, prolific producing trends. We have recently expanded our strategic focus to include longer reserve life resource plays that we believe provide significant long-term growth potential in multiple formations.

In late 2008 and early 2009, we acquired approximately 12,000 net acres in East Texas where we completed our first well, the Kardell #1H, in October 2009. This well targeted the Haynesville Shale and initially produced 30.7 MMcfe/d, which we believe to be the highest publicly announced initial production rate to date in that formation. In addition to the Haynesville Shale, we believe this acreage is equally prospective in the Bossier Shale and James Lime formations where industry participants have drilled successful wells on adjacent acreage.

In 2007, we acquired approximately 2,800 net acres in South Texas, which we believe is prospective in the Austin Chalk and the Eagle Ford Shale. We drilled our first well on this acreage, the Dubose #1, during the fourth quarter of 2009, and we are preparing to complete the well in the Eagle Ford Shale.

We intend to grow reserves and production by developing our existing producing property base, developing our East Texas and South Texas resource potential, and pursuing opportunistic acquisitions in areas where we have specific operating expertise. We have developed a significant project inventory of over 800 drilling locations associated with our existing property base. Our technical team has a successful track record of adding reserves through the drillbit. Since January 2008, we have drilled 34 gross (15.2 net) wells with an overall success rate of 91% (excluding one well which has not yet been completed).

As of December 31, 2008, our estimated proved reserves, as prepared by our independent reserve engineering firm, Netherland, Sewell & Associates, Inc., were 131.9 Bcfe, consisting of 96.2 Bcf of natural gas and 6.0 MMBbl of crude oil, condensate and natural gas liquids. As of December 31, 2008, 73% of our proved reserves were natural gas, 69% were proved developed and 81% were attributed to wells and properties operated by us. From 2006 to 2008, we grew our estimated proved reserves from 46.4 Bcfe to 131.9 Bcfe. In addition, we grew our average daily production from 7.3 MMcfe/d for the year ended December 31, 2006 to 43.0 MMcfe/d for the nine months ended September 30, 2009. For the nine months ended September 30, 2009, we generated $55.2 million of Adjusted EBITDAX. Our definition of the non-GAAP financial measure of Adjusted EBITDAX and a reconciliation of net income (loss) to Adjusted EBITDAX are provided under Prospectus Summary Non-GAAP Financial Measures and Reconciliations. For the same period, our net income (loss) was $(16.8) million.

Our areas of primary focus include the following:

> *East Texas.* Our East Texas properties includes approximately 17,000 gross (12,000 net) acres acquired in 2008 and early 2009 in the highly prospective and active resource play in San Augustine and Sabine Counties, where we will focus primarily on the pursuit of the Haynesville Shale, Bossier Shale and James Lime formations. In October 2009, we drilled and completed our first well in this area, the Kardell #1H. While drilling this well, we identified additional prospective formations, including the Pettet and Knowles Lime.

Southeast Texas. Our Southeast Texas properties primarily include the Felicia field area in Liberty County. We own approximately 27,300 gross (15,100 net) acres in Liberty, Madison and Grimes Counties. As of September 30, 2009, we owned and operated 35 gross (27.0 net) producing wells, representing approximately 38% of our average daily production for the first nine months of 2009.

South Texas. Our South Texas properties include approximately 2,800 gross (2,800 net) acres in Bee County, which we believe to be prospective in the Austin Chalk and Eagle Ford Shale. Our conventional operations include approximately 87,600 gross (50,700 net) acres predominantly in Brooks, Lavaca, DeWitt, Zapata, Webb and Matagorda Counties.

We also own interests in the following areas:

Colorado and Other. Our Colorado and other properties include primarily producing assets and approximately 16,900 gross (11,900 net) acres in the Denver Julesburg Basin in Colorado (mostly in Adams County) and a minor crude oil property in Mississippi.

Southwest Louisiana. Our Southwest Louisiana properties include approximately 8,200 gross (3,600 net) acres, primarily in the Fenton field area of Calcasieu Parish and our legacy Grand Lake and Lacassine fields in Cameron Parish. In addition, we own a 15% working interest ownership in 2007 exploratory successes in Louisiana at Sabine Lake and West Cameron 432. On November 24, 2009, we entered into a purchase and sale agreement for the sale of substantially all of our Southwest Louisiana properties. See Management s Discussion and Analysis of Financial Condition and Results of Operations Recent Developments Southwest Louisiana Disposition.

The following table sets forth certain information with respect to our estimated proved reserves as of December 31, 2008, as estimated by Netherland, Sewell & Associates, Inc., and production and net acreage for the nine months ended September 30, 2009. The following table also identifies potential drilling locations and net acreage as of September 30, 2009:

	Proved Reserves					
Region	**Estimated Proved Reserves as of December 31, 2008 (MMcfe)**	**% Natural Gas**	**% Proved Developed**	**Average Daily Production for the Nine Months Ended September 30, 2009 (Mcfe/d)**	**Net acreage at September 30, 2009**	**Identified Potential Gross Drilling Locations at September 30, 2009[1]**
Southeast Texas	29,393	60.1%	85.8%	16,521	15,100	26
South Texas	60,602	78.0%	59.8%	11,963	53,500	124
Colorado and Other	6,675	71.5%	55.3%	539	11,900	164
East Texas[2]					12,000	422
Southwest Louisiana[3]	10,398	62.4%	57.3%	3,139	3,600	4
Non-operated[3][4]	24,879	80.2%	79.8%	10,817		82

Total	131,947	72.9%	68.9%	42,979	96,100	822

(1) Includes multiple drilling locations on acreage with multiple target formations.

(2) We recently completed our first well on our East Texas acreage, the Kardell #1H, as a horizontal Haynesville Shale producer, in which we own a 52% working interest. Drilling locations in this region were identified assuming an allocated 100 acres per potential horizontal East Texas well drilled to multiple target formations.

(3) On November 24, 2009, we entered into a purchase and sale agreement for the sale of substantially all of our operated and certain non-operated Southwest Louisiana properties. See Management s Discussion and Analysis of Financial Condition and Results of Operations Recent Developments Southwest Louisiana Disposition.

(4) Our non-operated properties consist primarily of our 25% working interest in the Samano field in Starr and Hidalgo Counties in South Texas, our 28% working interest in certain fields in Liberty County in Southeast Texas and our 15% and 15% respective working interests resulting from exploratory successes in 2007 at Sabine Lake and West Cameron 432, in Southwest Louisiana.

We have significantly increased our proved reserves and production through acquisitions and drilling since our recapitalization in early 2005. In 2007, we tripled our reserve size through the acquisition from EXCO of producing properties in the South Texas, Southeast Texas and Southwest Louisiana regions, adding an aggregate of approximately 95 Bcfe to our net proved reserves at a cost of $2.50 per Mcfe of proved reserves as of the effective date. We added 21 Bcfe to our South Texas proved reserves through the Smith acquisition in 2008 at an average cost of $2.82 per Mcfe of proved reserves as of the closing date. Our acquisitions are focused on areas in which we can leverage our geographic and geological expertise to exploit those drilling opportunities identified at the time of the acquisition and develop an inventory of additional drilling prospects that we believe will enable us to grow production and add reserves. We intend to continue to pursue the acquisition of assets in our core areas, to continue to selectively expand our presence in our East Texas resource play and to continue to develop exploratory opportunities through our internal prospect generation team.

We have also been successful at adding reserves through the drilling of non-proved targets through our exploitation program on existing producing properties. Since January 2008, we have drilled 34 gross wells (16 operated and 18 non-operated), with an overall success rate of 91% (excluding one well which has not yet been completed). We added approximately 18.4 Bcfe in proved reserves in 2008. We believe that we have a current inventory of 822 identified drilling opportunities on our producing asset base as noted in the table above.

During the latter half of 2008 and early 2009, we acquired approximately 12,000 net acres in San Augustine and Sabine Counties in East Texas, which we believed to be prospective in the Haynesville Shale, James Lime and Mid-Bossier formations. We have identified over 422 drilling locations on our acreage targeting these formations alone. Recent activity in the area also indicates that the Pettet and Knowles Lime formations also appear prospective. We have separated our acreage into several joint development areas (JDAs) of varying sizes and are working with other industry players holding acreage positions in those areas to jointly develop our positions. Our Bruin prospect, on which our first well, the Kardell #1H was drilled, is one such JDA. We and Devon Energy Corporation, the operator, each contributed approximately 350 acres to the JDA in San Augustine County and drilled the Kardell #1H well. Given the success we have had on the Kardell #1H well, we will likely allocate a large portion of our drilling capital budget to develop this resource play further for the next several years.

Strategy

The key elements of our business strategy are:

Develop our East Texas resource play. We have approximately 12,000 net acres in San Augustine and Sabine Counties of East Texas, which we believe is prospective in the Haynesville Shale, Bossier Shale and James Lime formations. In November 2009, we announced the completion and initial production of our first well on this acreage, the Kardell #1H. The well tested at 30.7 MMcfe/d, which we believe to be the highest publicly reported 24-hour initial production rate for a Haynesville Shale well in Texas or Louisiana and is currently flowing to sales. We believe the Kardell #1H confirms the potential of our Bruin Prospect, which is comprised of 3,000 net acres in San Augustine County, resulting in over 100 potential drilling locations in multiple formations. We are currently in the planning stages of several wells in this area and intend to further evaluate and exploit these multiple formations beginning in early 2010. We have an additional 9,000 net acres outside this prospect within Sabine and San Augustine Counties, and we expect to drill our initial well on that acreage in early 2010. We intend to allocate a substantial portion of our capital budget over the next several years to develop the significant potential that we believe exists on our East Texas acreage. Based on our current capital budget, we expect to drill approximately 7 gross (3.0 net) wells in 2010 that will target the Haynesville and Bossier Shales, while retaining future development opportunities in shallower formations.

Develop our South Texas resource play. We have approximately 2,800 net acres in Bee County, Texas which we believe is prospective in the Austin Chalk and Eagle Ford Shale. In November 2009, we drilled our initial well on this acreage, the Dubose #1. This well is in the process of being completed with results expected prior to year end 2009. We intend to allocate a portion of our capital budget in 2010 to validate the potential we believe exists on our acreage.

Exploit our existing producing property base to generate cash flows. We believe our multi-year drilling inventory of high return exploitation opportunities on our existing producing properties provides us with a solid platform to continue growing our reserves and production for the next several years. We believe these projects, if successful, will allow us to fund a larger portion of our resource plays and exploration activities from cash flows from operations. In 2010, we intend to focus much of our exploitation drilling on our Liberty County acreage, located in Southeast Texas. We will be targeting the Yegua and Cook Mountain formations in which industry players have recently experienced success on wells in the area. We own 3D seismic data that covers substantially all of our Liberty County acreage, giving us a higher degree of confidence in the potential in this area. We have drilled 11 gross (6.8 net) wells in Liberty County since early 2008 and have successfully completed 82%. During 2010, we intend to drill 4 gross (2.6 net) wells in this area.

Explore in defined producing trends. Our exploration activities consist primarily of step-out drilling in known, producing formations in our legacy areas of South and Southeast Texas. In 2007, we began acquiring seismic data to use in identifying new exploration prospects. Currently, we have a library of over 4,200 square miles of 3D seismic data and over 2,500 linear miles of 2D seismic data.

Make opportunistic acquisitions that meet our strategic and financial objectives. We seek to acquire natural gas and crude oil properties, including both undeveloped and producing reserves in areas where we have specific operating expertise.

Reduce commodity exposure through hedging. We employ the use of swaps and costless collar derivative instruments to limit our exposure to commodity prices. As of September 30, 2009, we had 13.9 Bcfe of equivalent production hedged, representing 1.8 Bcf, 6.1 Bcf and 3.2 Bcf of natural gas hedges in place and 86 MBbl, 250 MBbl and 124 MBbl of crude oil hedges in place for the fourth quarter of 2009, the year 2010 and the year 2011, respectively. The average price of our natural gas and crude oil hedges in place is $8.19/MMBtu and $86.03/Bbl for the fourth quarter of 2009, $7.71/MMBtu and $83.02/Bbl in the year 2010 and $7.32/MMBtu and $66.50/Bbl in the year 2011.

Competitive Strengths

Our competitive strengths include:

Geographically focused operations in basins with established production profiles. The geographic concentration of our current operations along the onshore Texas Gulf Coast and in South Texas allows us to establish economies of scale with respect to drilling, production, operating and administrative costs, and enables us to leverage our base of technical expertise in these geographic areas. In addition, we believe the cash flows from our existing properties provide a stable foundation to support our ongoing exploitation and development efforts.

Significant operational control. As of September 30, 2009, we operated a majority of our producing wells. As a result, we exercise a significant level of control over the amount and timing of expenses, capital allocation and other aspects of development, exploitation and exploration. While operatorship of future wells on our East Texas acreage will be subject to negotiation as drilling units are formed, we expect to operate a significant number of the wells we drill on this acreage.

Proven track record of reserve and production growth. Since 2005, we have significantly grown proved reserves and production through a combination of continued drilling success and the successful acquisition of underdeveloped properties that have proven to be complementary to our existing asset base and technical expertise. We plan to continue this growth by focusing on a balanced combination of drilling longer life, multi-pay natural gas targets within our resource plays and exploitation of our producing properties and undeveloped acreage.

Large inventory of identified projects. We currently have an inventory of over 800 identified potential drilling locations, including 375 associated with our existing conventional properties, plus an estimated 422 locations on our East Texas resource play acreage and an estimated 25 locations on our South Texas resource play acreage. Since the beginning of 2008, we have drilled 16 gross (10.7 net) operated and 18 gross (4.5 net) non-operated wells and have experienced a 91% success rate (excluding one well which has not yet been completed). We expect to drill 12 gross (6.0 net) wells in 2010.

Experienced management and technical teams. Our senior management team averages over 25 years of experience in the energy industry and is led by Allan D. Keel, President and Chief Executive Officer, who has 25 years of experience in the oil and natural gas industry. Mr. E. Joseph Grady, our Senior Vice President and Chief Financial Officer, has over 30 years of financial management experience in the energy industry. Other members of our senior management include: Mr. Tracy Price, our Senior Vice President Land Business/Development; Mr. Thomas H. Atkins, our Senior Vice President Exploration; and Mr. Jay S. Mengle, our Senior Vice President Engineering, each of whom has more than 25 years of experience in the oil and gas industry. Our experienced management team has an established track record of successfully exploiting and developing natural gas and crude oil properties.

Properties

As of September 30, 2009, we operated a majority of our producing wells and held an average 52% (75% operated and 25% non-operated) working interest. Gross wells are the total wells in which we own a working interest. Net wells are the sum of the fractional working interests we own in gross wells. Our estimated net proved reserves were approximately 2.6 MMBbls of crude oil and condensate 96.2 Bcf of natural gas and 3.4 MMBbls of natural gas liquids at December 31, 2008. Substantially all of our properties are located onshore in Texas and Louisiana. As of December 31, 2008, our properties were located in the following regions: Southeast Texas, South Texas, Southwest Louisiana and Colorado and Other, although we separately classify our non-operated properties in our regions as Non-Operated. Given our success in 2009 with the first well on our East Texas acreage, the Kardell #1H, we intend to allocate a substantial portion of our drilling capital budget in the next several years to the development of the significant potential that we believe exists in this area.

Our estimated net proved reserves as of December 31, 2008, were approximately 72.9% natural gas, 15.4% natural gas liquids and 11.7% crude oil and condensate. As of December 31, 2008, approximately 68.9% of total proved reserves were classified as proved developed. The average remaining proved developed producing reserves per net operated well at December 31, 2008 was 356.4 MMcfe. Our estimated net proved reserves at December 31, 2008 had estimated PV-10 of $291.0 million. Our estimated net proved reserves as of September 30, 2009, were approximately

70.4% natural gas, 16.1% natural gas liquids and 13.5% crude oil and condensate. As of September 30, 2009, approximately 68% of total proved reserves were classified as proved developed. The average remaining proved developed producing reserves per net well at September 30, 2009 was 288.3 MMcfe. Our estimated net proved reserves at September 30, 2009 had estimated PV-10 of $190.8 million.

Our average proved reserves-to-production ratio, or average reserve life, is approximately 8.4 years based on our proved reserves as of December 31, 2008 and production for the nine months ended September 30, 2009 on an annualized basis. During 2008, 15 gross (10.3 net) operated wells and 17 gross (4.0 net) non-operated wells were drilled, 93% and 88% respectively of which were successes. During the nine months ended September 30, 2009, we drilled one gross (0.4 net) operated well, which has not yet been evaluated. We also drilled one gross (0.5 net) non-operated well in our East Texas acreage, which was a success. In 2010, we currently expect to drill 12 gross (6.0 net) wells. Also, as of September 30, 2009, we had identified 66 proved undeveloped drilling locations and 756 other drilling locations.

Operated Properties

East Texas

East Texas includes 17,000 gross (12,000 net) acres acquired in the latter half of 2008 and early 2009 in the highly prospective and active resource play in San Augustine and Sabine Counties, in which we will focus primarily on the pursuit of the Haynesville Shale, Bossier Shale and James Lime formations. Other potential formations that were seen in our Kardell #1H well (a non-operated well), and that are believed to be prospective in the area, are the Pettet and Knowles Lime. In the past year, the Haynesville Shale formation has become one of the most active natural gas plays in the United States, primarily in Northern Louisiana and East Texas. The formation is as much as 300 feet thick and exists at depths ranging from 10,500 to more than 13,500 feet. The Haynesville Shale has proven productive across numerous parishes in Northwest Louisiana and counties in East Texas, primarily Harrison, Panola and Shelby. We have identified 422 drilling locations in this area, based on 100-acre spacing. We are actively pursuing joint venture opportunities with third parties to develop our Haynesville Shale acreage in Texas. While operatorship of future wells on our East Texas acreage will be subject to negotiation as drilling units are formed, we expect to operate a significant number of the wells we drill on this acreage.

Southeast Texas

Our Southeast Texas properties consist primarily of the Felicia field area in Liberty County, Texas, which we acquired in the EXCO acquisition. We believe that the Liberty County area will continue to provide accelerated production and high rates of return as we exploit our probable and possible opportunities targeting the Yegua and Cook Mountain formations. We currently plan to drill or sidetrack 4 gross (2.6 net) wells during 2010 in Liberty County. The Southeast Texas region also includes the Madisonville/Iola area in Madison and Grimes Counties, which has deeper Smackover potential to complement our current Yegua, Frio, Cook Mountain and Rodessa production.

As of September 30, 2009, in Southeast Texas, we owned and operated 35 gross (27.0 net) producing wells. Our operated wells have an average working interest of 75% and an average net revenue interest of 60%. These wells produce crude oil and natural gas from various formations at depths from 2,000 to 16,300 feet. We principally produce from the Frio, Yegua, Cook Mountain and Rodessa formations. We own 27,300 gross (15,100 net) acres in Southeast Texas.

The average net production from our Southeast Texas properties for the year ended December 31, 2008 was 20.6 MMcfe/d, or approximately 39% of our 2008 total net equivalent production. The average net production from our Southeast Texas properties for the nine months ended September 30, 2009 was 16.5 MMcfe/d, or approximately

38% of our total net equivalent production for the nine months ended September 30, 2009. The average net production per net well for the year ended December 31, 2008 and for the nine months ended September 30, 2009 was 0.8 MMcfe/d and 0.6 MMcfe/d, respectively.

Our estimated net proved reserves for our Southeast Texas properties as of December 31, 2008, were 29,393 MMcfe, of which approximately 80.3% were natural gas and natural gas liquids and 85.8% were classified as proved developed. The average remaining proved developed producing reserves per net operated well at December 31, 2008 was 672.7 MMcfe. Our estimated net proved reserves at December 31, 2008 had estimated PV-10 of $89.7 million.

Our average reserve life for this region is approximately five years based on our proved reserves as of December 31, 2008 and production for the nine months ended September 30, 2009 on an annualized basis. During 2008, 8 gross (5.6 net) wells were drilled on our Southeast Texas properties, 88% of which were successes, and during the nine months ended September 30, 2009, no wells were drilled in Southeast Texas. Also, as of September 30, 2009, we had identified five proved undeveloped drilling locations and 21 other drilling locations on our Southeast Texas leasehold acreage. Our drilling opportunities for Southeast Texas have an average estimated well life of eight years.

South Texas

Our South Texas properties consist primarily of: the Cage Ranch field in Brooks County and Southwest Speaks field in Lavaca County, both acquired in the EXCO acquisition; the North Bob West field in Zapata County and the Brushy Creek field in DeWitt County, both acquired in the Smith acquisition; and Lobo trend production and acreage in Zapata and Webb Counties. We own approximately 90,400 gross (53,500 net) acres in these known prolific trends that we intend to continue to exploit.

We also own approximately 2,800 gross (2,800 net) acres in the Edwards Trend, which we call our NW Pawnee prospect, that we believe not only contains the Edwards/Sligo formations, but also believe to be prospective in the Austin Chalk and the Eagle Ford Shale. We recently drilled and are in the process of completing, the Dubose #1 well, our first well on this acreage. If this well is successful, we plan to drill additional wells in this area during 2010.

As of September 30, 2009, in South Texas, we owned and operated 94 gross (73.0 net) producing wells. Our operated wells have an average net working interest of 73% and an average net revenue interest of 58%. These wells produce crude oil and natural gas from various formations at depths from 2,000 to 19,400 feet. We principally produce from the Wilcox, Vicksburg and Lobo formations.

The average net production from our South Texas properties for the year ended December 31, 2008 was 9.7 MMcfe/d, or approximately 19% of our 2008 total net equivalent production. The average net production from our South Texas properties for the nine months ended September 30, 2009 was 12.0 MMcfe/d, or approximately 28% of our total net equivalent production for the nine months ended September 30, 2009. The average net production per operated net well for the year ended December 31, 2008 and for the nine months ended September 30, 2009 was 0.1 MMcfe/d and 0.2 MMcfe/d, respectively.

Our estimated net proved reserves at December 31, 2008 for our South Texas properties were 60,602 MMcfe, of which approximately 94.6% were natural gas and natural gas liquids and 59.8% were classified as proved developed. The average remaining proved developed producing reserves per net well at December 31, 2008 was 277.0 MMcfe. Our estimated net proved reserves at December 31, 2008 had an estimated PV-10 of $101.8 million.

Our average reserve life for this region is approximately 14 years based on our proved reserves as of December 31, 2008 and production for the nine months ended September 30, 2009 on an annualized basis. During 2008, 7 gross (4.7 net) wells were drilled on our South Texas properties, 100% of which were successes. During the nine months ended September 30, 2009, one gross (0.4 net) well

was drilled in South Texas (the Dubose #1), which has not been completed. In 2009, we currently expect to drill one gross well (0.4 net) on our South Texas resource play acreage. Also, as of September 30, 2009, we had identified 24 additional proved undeveloped drilling locations and over 100 other drilling locations on our South Texas leasehold acreage. Our drilling opportunities for South Texas have an average estimated well life of 15 years.

Colorado and Other

We also own properties in Colorado, Mississippi and other areas (Other Properties), none of which is a current area of focus for drilling. However, our Other Properties do serve to broaden our range and diversify our risk. These properties currently consist primarily of our legacy production and exploitation potential in the Denver Julesburg Basin in Colorado, which is primarily in Adams County. We own approximately 9,500 gross (6,700 net) undeveloped acres in this area that are held by production, that appear to be prospective in the basin and for which we will endeavor to find a local partner to participate in developing that acreage. We also own a minor crude oil property in Mississippi. Our Other Properties represent 6,675 MMcfe of proved reserves or 5.1% of our total proved reserves of December 31, 2008.

As of September 30, 2009, in our Colorado and Other Properties, we owned and operated 30 gross (22.0 net) producing wells. Our operated wells have an average working interest of 74% and an average net revenue interest of 59%. These wells produce crude oil and natural gas from various formations at depths from 2,000 to 17,500 feet. We principally produce from the Denver and Julesberg Sand formations in Colorado. We also own 16,900 gross (11,900 net) acres in these areas, most of which is held by production.

The average net production from our Colorado and Other Properties for the year ended December 31, 2008 was 0.9 MMcfe/d, or approximately 1.6% of our 2008 total net equivalent production. The average net production from our Colorado and Other Properties for the nine months ended September 30, 2009 was 0.5 MMcfe/d, or approximately 1% of our total net equivalent production for the nine months ended September 30, 2009. The average net production per net well for the year ended December 31, 2008 and for the nine months ended September 30, 2009 was 0.05 MMcfe/d and 0.01 MMcfe/d, respectively.

Our estimated net proved reserves at December 31, 2008 for our Colorado and Other Properties were 6,675 MMcfe, of which approximately 71.5% were natural gas and natural gas liquids and 55.3% were classified as proved developed. The average remaining proved developed producing reserves per net well at December 31, 2008 was 157.9 MMcfe. Our estimated net proved reserves at December 31, 2008 had an estimated PV-10 of $7.0 million.

Our average reserve life in this region is approximately 34 years based on our proved reserves as of December 31, 2008 and production for the nine months ended September 30, 2009 on an annualized basis. We did not drill any wells on our Colorado and Other Properties in 2008 or during the first nine months of 2009. Our drilling opportunities for Colorado and Other Properties have an average estimated well life of 18 years. We recently contracted with a geological consulting group that specializes in the Denver Julesburg Basin, and that group has identified 151 drilling locations on our acreage as of September 30, 2009. Because of the upside potential, we are currently pursuing a relationship with an industry partner experienced in the Denver Julesburg Basin area to test that additional potential.

Southwest Louisiana

Our Southwest Louisiana properties consist primarily of the Fenton field area in Calcasieu Parish, acquired in the EXCO acquisition, and our legacy Grand Lake and Lacassine fields in Cameron Parish. In total, we own approximately 8,200 gross (3,600 net) acres in these large and prolific areas. On November 24, 2009, we entered into a purchase and sale agreement for the sale of substantially all of our Southwest Louisiana properties. See Management s Discussion and Analysis of Financial

Condition and Results of Operations Overview Recent Developments Southwest Louisiana Disposition.

As of September 30, 2009, in Southwest Louisiana, we owned and operated 16 gross (9.0 net) producing wells. Our operated wells have an average net working interest of 51% and an average net revenue interest of 40%. We also owned 8,200 gross and 3,600 net acres in Southwest Louisiana.

The average net production from our Southwest Louisiana properties for the year ended December 31, 2008 was 5.9 MMcfe/d, or approximately 11% of our 2008 total net equivalent production. The average net production from our Southwest Louisiana properties for the nine months ended September 30, 2009 was 3.1 MMcfe/d, or approximately 7% of our total net equivalent production for the nine months ended September 30, 2009. The average net production per operated net well for the year ended December 31, 2008 and for the nine months ended September 30, 2009 was 0.5 MMcfe/d and 0.4 MMcfe/d, respectively.

Our estimated net proved reserves at December 31, 2008 for our Southwest Louisiana properties were 10,398 MMcfe, of which approximately 75.5% were natural gas and natural gas liquids and 57.3% were classified as proved developed. The average remaining proved developed producing reserves per net well at December 31, 2008 was 397.5 MMcfe. Our estimated net proved reserves at December 31, 2008 had an estimated PV-10 of $27.2 million and at September 30, 2009 had an estimated PV-10 of $19.9 million.

Non-Operated Properties

Though not a geographic region, we segregate our non-operated properties and treat them as a separate region, in order to allow our technical and operational teams dedicated to our operated regions to focus on those properties on which we have the ability to exercise operational and development control. Our non-operated properties consist primarily of our 25% working interest in the Samano field in Starr and Hidalgo Counties in South Texas, which we acquired in the Smith acquisition, our 28% working interest in certain fields in Liberty County in Southeast Texas and our 15% and 15% respective working interests resulting from exploratory successes in 2007 at Sabine Lake and West Cameron 432, in Southwest Louisiana. On November 24, 2009, we entered into a purchase and sale agreement for the sale of substantially all our operated and certain non-operated properties in Southwest Louisiana. See Management s Discussion and Analysis of Financial Condition and Results of Operations Recent Developments Southwest Louisiana Disposition.

As of September 30, 2009, we owned various working interests in 170 existing non-operated producing wells, with an average working interest of 25% and an average net revenue interest of approximately 19%. These wells produce crude oil and natural gas from various formations at depths from 2,000 to 17,500 feet.

The average net production from our non-operated properties for the year ended December 31, 2008 was 15.5 MMcfe/d, or approximately 29% of our 2008 total net equivalent production. The average net production from our non-operated properties for the nine months ended September 30, 2009 was 10.9 MMcfe/d, or approximately 25% of our total net equivalent production for the nine months ended September 30, 2009. The average net production per non-operated net well for the year ended December 31, 2008 and for the nine months ended September 30, 2009 was 0.4 MMcfe/d and 0.3 MMcfe/d, respectively.

Our estimated net proved reserves at December 31, 2008 for our non-operated properties were 24,879 MMcfe, of which approximately 92.5% were natural gas and natural gas liquids and 79.8% were classified as proved developed. The average remaining proved developed producing reserves per net well at December 31, 2008 was 385.5 MMcfe. Our estimated net proved reserves at December 31, 2008 had estimated PV-10 of $65.3 million.

Our average reserve life in this region is approximately six years based on our proved reserves as of December 31, 2008 and production for the nine months ended September 30, 2009 on an

Table of Contents

annualized basis. During 2008, 17 gross (4.0 net) wells were drilled on our Non-Operated properties, 88% of which were successes, and during the nine months ended September 30, 2009 we did not participate in any wells. Also, as of September 30, 2009, we had identified 22 additional proved undeveloped drilling locations and 60 other drilling locations on our non-operated leasehold acreage. A typical well in our non-operated properties has a predictable production profile and a standard economic life of approximately 19 years.

Proved Reserves

The following tables reflect our estimated proved reserves at December 31 for each of the preceding three years and at September 30, 2009. The following tables do not give effect to the disposition of substantially all of our Southwest Louisiana properties. See Management s Discussion and Analysis of Financial Condition and Results of Operations Recent Developments Southwest Louisiana Disposition. All information provided herein relating to our proved reserves is taken or derived from reports prepared by Netherland, Sewell & Associates, Inc., independent petroleum engineers. The estimates of these engineers were based upon their review of production histories and other geological, economic, ownership and engineering data provided by and relating to us.

		December 31,		September 30,
	2006	2007	2008	2009
Crude Oil (MBbl)				
Developed	2,249	2,266	1,616	1,459
Undeveloped	252	637	948	899
Total	2,501	2,903	2,564	2,358
Natural Gas (MMcf)				
Developed	27,145	67,997	66,712	49,540
Undeveloped	4,243	23,242	29,457	24,228
Total	31,388	91,239	96,169	73,768
Natural Gas Liquids (Bbls)				
Developed		2,684	2,423	2,159
Undeveloped		906	976	664
Total		3,590	3,399	2,823
Total (MMcfe)	46,394	130,197	131,947	104,854
Proved developed reserves percentage	88%	75%	69%	68%
PV-10 (in millions)(1)	$ 102.4	$ 531.4	$ 291.0	$ 190.8
Estimated reserve life (in years)	17.5	9.8	6.9	6.7
Prices utilized in estimates(2):				
Natural gas (MMBtu)	$ 6.03	$ 6.80	$ 5.71	$ 3.30
Crude oil (Bbl)	$ 61.06	$ 92.50	$ 41.00	$ 67.00

(1)

PV-10 is a non-GAAP financial measure. A reconciliation of our standardized measure to PV-10 is provided under Prospectus Summary Non-GAAP Financial Measures and Reconciliations.

(2) Natural gas prices are based on Henry Hub spot price at year end, except for 2006 which is based on NYMEX prices. Oil prices are based upon year end West Texas Intermediate posted prices. Under new SEC rules, prices used in determining our proved reserves as of December 31, 2009 will be based upon an unweighted 12-month first day of the month average price of $3.87 per MMBtu (Henry Hub spot) of natural gas and $57.65 per barrel of oil (West Texas Intermediate posted). These are adjusted for quality, energy content, transportation fees and regional price differentials.

Table of Contents

The following tables reflect our estimated proved reserves by category as of December 31, 2008. Approximately 69% of our total proved reserves was classified as proved developed at December 31, 2008.

	Crude Oil (MBbl)	Gas (MMcf)	Natural Gas Liquids (MBbl)	Total (MMcfe)	% of Total Proved	PV-10 *(In millions)*
Proved developed producing	1,165	48,458	1,630	65,228	49.4%	$ 180.1
Proved developed non-producing	451	18,254	793	25,718	19.5%	55.7
Proved undeveloped	948	29,457	976	41,001	31.1%	55.2
Total	2,564	96,169	3,399	131,947	100%	$ 291.0

The following tables reflect our estimated proved reserves by category as of September 30, 2009. Approximately 68% of our total proved reserves was classified as proved developed at September 30, 2009.

	Crude Oil (MBbl)	Gas (MMcf)	Natural Gas Liquids (MBbl)	Total (MMcfe)	% of Total Proved	PV-10 *(In millions)*
Proved developed producing	997	34,990	1,532	50,164	47.8%	$ 110.4
Proved developed non-producing	462	14,550	627	21,084	20.1%	40.7
Proved undeveloped	899	24,228	664	33,606	32.1%	39.7
Total	2,538	73,768	2,823	104,854	100%	$ 190.8

Standardized Measure of Discounted Future Net Cash Flows

The following table sets forth as of December 31 for each of the preceding three years, the estimated future net cash flow from and standardized measure of discounted future net cash flows of our proved reserves, which were prepared in accordance with the rules and regulations of the SEC and the Financial Accounting Standards Board. Future net cash flow represents future gross cash flow from the production and sale of proved reserves, net of crude oil, natural gas and natural gas liquids production costs (including production taxes, ad valorem taxes and operating expenses) and future development costs. The calculations used to produce the figures in this table are based on current cost and price factors at December 31 for each year. We cannot assure you that the proved reserves will all be developed within the periods used in the calculations or those prices and costs will remain constant. A standardized measure of discounted future net cash flows is not required to be presented for interim financial presentation dates.

	2006	2007	2008
		(In thousands)	
Future cash inflows	$ 313,313	$ 1,125,375	$ 749,121
Future production and development costs:			
Production	108,694	258,029	214,969
Development	26,229	65,779	86,068
Future cash flows before income taxes	178,390	801,567	448,084
Future income taxes	(43,534)	(198,921)	(46,696)
Future net cash flows after income taxes	134,856	602,646	401,388
10% annual discount for estimated timing of cash flows	(57,443)	(203,123)	(140,486)
Standardized measure of discounted future net cash flows	$ 77,413	$ 399,523	$ 260,902

Table of Contents

All information provided herein relating to our proved reserves, estimated future net cash flows and present values is taken or derived from reports prepared by Netherland, Sewell & Associates, Inc., independent petroleum engineers. The estimates of these engineers were based upon their review of production histories and other geological, economic, ownership and engineering data provided by and relating to us. No reports on our reserves have been filed with any federal agency. In accordance with the SEC s guidelines, our estimates of proved reserves and the future net revenues from which present values are derived are made using year end crude oil and natural gas sales prices held constant throughout the life of the properties (except to the extent a contract specifically provides otherwise). Operating costs, development costs and certain production-related taxes were deducted in arriving at estimated future net revenues, but such costs do not include debt service, general and administrative expenses and income taxes.

There are numerous uncertainties inherent in estimating crude oil and natural gas reserves and their values, including many factors beyond our control. The reserve data included in this report are based upon estimates. Reservoir engineering is a subjective process, which involves estimating the sizes of underground accumulations of crude oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation of that data and judgment. As a result, estimates of different engineers, including those used by us, may vary. In addition, estimates of reserves are subject to revision based upon actual production, results of future development, exploitation and exploration activities, prevailing crude oil and natural gas prices, operating costs and other factors. Such revisions may be material. Accordingly, reserve estimates are often different from the quantities of crude oil and natural gas that are ultimately recovered and are highly dependent upon the accuracy of the assumptions upon which they are based. We cannot assure you that the estimates contained in this report are accurate predictions of our crude oil and natural gas reserves or their values. Estimates with respect to proved reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than upon actual production history. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history will result in potentially substantial variations in the estimated reserves.

Significant Properties

Summary information on our properties with proved reserves is provided below as of December 31, 2008.

	Productive Wells		**Proved Reserves**				
Regions	**Gross Productive Wells**	**Net Productive Wells**	**Crude Oil** *(MBbl)*	**Natural Gas** *(MMcf)*	**Natural Gas Liquids** *(MBbl)*	**Total** *(MMcfe)*	**PV-10[(1)(2)]** *($M)*
South Texas	105	82	545	47,284	1,675	60,602	$ 101,838
Southeast Texas	35	27	965	17,669	988	29,393	89,685
Colorado and Other	25	19	317	4,775		6,675	7,002
Southwest Louisiana[(3)]	21	12	425	6,490	227	10,398	27,162
Non-Operated[(3)]	172	43	312	19,951	509	24,879	65,263
Total	358	183	2,564	96,169	3,399	131,947	$ 290,950

(1)

The prices utilized in the estimation of our 2008 proved reserves were based on the West Texas Intermediate posted prices on December 31, 2008 of $41.00 per barrel for crude oil and the Henry Hub spot market price of $5.71 per MMBtu for natural gas. All prices were adjusted by lease for quality, energy content, transportation fees and regional price differentials.

(2) PV-10 is a non-GAAP financial measure. A reconciliation of our standardized measure to PV-10 is provided under Prospectus Summary Non-GAAP Financial Measures and Reconciliations.

(3) On November 24, 2009, we entered into a purchase and sale agreement for the sale of substantially all of our operated and certain non-operated Southwest Louisiana properties. See Management s Discussion and Analysis of Financial Condition and Results of Operations Recent Developments Southwest Louisiana Disposition.

Production, Revenue and Price History

The following table sets forth information (associated with our proved reserves) regarding production volumes of crude oil, natural gas and natural gas liquids, revenues and expenses attributable to such production (all net to our interests) and certain price and cost information as of December 31 for each of the preceding three years and for the nine months ended September 30, 2009:

	December 31, 2006	December 31, 2007	December 31, 2008	September 30, 2009
Production				
Natural gas (Mcf)	1,542,423	9,067,777	13,135,509	8,142,588
Crude oil (Bbl)	184,881	408,864	498,143	264,170
Natural gas liquids (Bbl)		285,907	516,352	334,303
Total (Mcfe)	2,651,709	13,236,403	19,222,479	11,733,426
Revenue (in thousands)				
Natural gas sales	$ 10,570	$ 67,868	$ 116,415	$ 55,135
Crude oil sales	10,908	27,021	41,860	21,519
Natural gas liquids sales		14,273	27,405	9,089
Total	$ 21,478	$ 109,162	$ 185,680	$ 85,743
Production Data				
Average sales price (before hedging)				
Per Mcf of natural gas	$ 6.76	$ 6.78	$ 8.92	$ 3.92
Per barrel of crude oil	$ 63.29	$ 74.38	$ 101.13	$ 52.80
Per barrel of natural gas liquids	$	$ 49.92	$ 53.07	$ 27.19
Per Mcfe	$ 8.34	$ 8.02	$ 10.14	$ 4.68
Average sales price (after hedging)(1)				
Per Mcf of natural gas	$ 6.85	$ 7.48	$ 8.86	$ 6.77
Per barrel of crude oil	$ 59.00	$ 66.09	$ 84.03	$ 81.46
Per barrel of natural gas liquids	$	$ 49.92	$ 53.07	$ 27.19
Per Mcfe	$ 8.10	$ 8.25	$ 9.66	$ 7.31
Average expenses per Mcfe				
Lease operating	$ 2.12	$ 0.91	$ 1.08	$ 1.15
Production and ad valorem taxes	$ 0.71	$ 0.88	$ 0.85	$ 0.52
Exploration expenses(2)	$ 0.25	$ 0.24	$ 0.52	$ 0.24
Depreciation, depletion and amortization	$ 1.52	$ 2.33	$ 2.63	$ 3.55
General and administrative(3)	$ 3.29	$ 1.10	$ 1.17	$ 1.14

(1) Average sales prices are shown net of the settled amounts of our natural gas, crude oil and natural gas liquids hedge contracts.

(2) In November 2008, we released undeveloped leasehold interests that we acquired from Core Natural Resources in Culberson County, Texas in 2006, and recorded a $7.1 million exploration expense.

(3) Non-cash stock compensation expense on January 1, 2006 was $0.16, $0.26, $0.32 and $1.39 per Mcfe in the nine months ended September 30, 2009, the years ended December 31, 2008, 2007 and 2006, respectively.

Productive Wells

The following table shows the number of producing wells we owned by location at September 30, 2009:

	Gross Crude Oil Wells	Net Crude Oil Wells	Gross Natural Gas Wells	Net Natural Gas Wells
South Texas	1	1	93	72
Southeast Texas	7	6	28	21
Southwest Louisiana	8	6	8	4
Colorado and Other	21	15	9	7
Non-operated	18	3	152	40
Total	55	31	290	144

In addition, as of September 30, 2009, we had 171 inactive wells and 26 salt water disposal wells.

Developed and Undeveloped Acreage

Developed acreage is acreage spaced or assigned to productive wells. Undeveloped acreage is acreage on which wells have not been drilled or completed to a point that would form the basis to determine whether the property is capable of production of commercial quantities of natural gas, crude oil and natural gas liquids. Gross acres are the total acres in which we own a working interest. Net acres are the sum of the fractional working interests we own in gross acres. The following table shows the approximate developed and undeveloped acreage that we have an interest in, by location, at September 30, 2009.

	Developed		Undeveloped	
	Gross Acres	Net Acres	Gross Acres	Net Acres
South Texas	74,100	39,500	16,300	14,000
Southeast Texas	23,400	12,800	3,900	2,300
Southwest Louisiana	7,200	2,700	1,000	900
Colorado & Other	7,400	5,200	9,500	6,700
East Texas	500	200	16,500	11,800
Total	112,600	60,400	47,200	35,700

Table of Contents

Drilling Results

The following table shows the results of the wells drilled and completed for operated and non-operated properties for each of the last three fiscal years ended December 31, 2008 and the nine months ended September 30, 2009. No crude oil wells were drilled during this time period.

	December 31, 2006	December 31, 2007	December 31, 2008	September 30, 2009
Gross Wells				
Development	4	9	20	4
Exploratory		8	5	
Dry		4	2	1
Total	4	21	27	5
Net Wells				
Development	3.50	1.07	10.74	1.74
Exploratory		1.65	1.05	
Dry		0.72	0.80	0.39
Total	3.50	3.44	12.59	2.13

At December 31, 2008, we had no exploratory and 4 gross (1.1 net) development wells in progress. At September 30, 2009, we had two gross (0.9 net) exploratory wells and no development wells.

Costs Incurred

The following table shows the costs incurred in our crude oil and gas producing activities for the past three years and for the nine months ended September 30, 2009:

	December 31, 2006	December 31, 2007	December 31, 2008	September 30, 2009
		(In thousands)		
Property Acquisitions:				
Proved	$	$ 238,036	$ 60,765	$ (494)
Unproved	8,745	30,408	57,203	1,490
Development Costs	6,466	30,815	86,685	10,859
Exploration Costs	10,784	13,405	2,520	7,248
Total	$ 25,995	$ 312,664	$ 207,173	$ 19,103

These costs include crude oil and gas property acquisition, exploration and development activities regardless of whether the costs were capitalized or charged to expense, including lease rental expenses and geological and geophysical expenses.

Property Dispositions

The following table shows crude oil and gas property dispositions for the three years ended December 31, 2008 and for the nine months ended September 30, 2009:

	December 31,			September 30,
	2006	2007	2008	2009
			(In thousands)	
Crude oil and gas properties	$	$	$ 21,766	$ 11
Accumulated DD&A			(1,660)	
Crude oil and gas properties, net	$	$	$ 20,106	$ 11

The dispositions in 2008 resulted in a net gain of $15.2 million.

Marketing

We sell a significant portion of our natural gas production to purchasers pursuant to sales agreements which contain a primary term of up to two years and crude oil production to purchasers under sales agreements with primary terms of up to one year. The sales prices for natural gas are tied to industry standard published index prices, subject to negotiated price adjustments, while the sale prices for crude oil are tied to industry standard posted prices subject to negotiated price adjustments.

Competition

The oil and gas industry is highly competitive and we compete with a substantial number of other companies that have greater resources. Many of these companies explore for, produce and market crude oil and natural gas, carry on refining operations and market the resultant products on a worldwide basis. The primary areas in which we encounter substantial competition are in locating and acquiring desirable leasehold acreage for our drilling and development operations, locating and acquiring attractive producing oil and gas properties, and obtaining purchasers and transporters of the crude oil and natural gas we produce. There is also competition between producers of crude oil and natural gas and other industries producing alternative energy and fuel. Furthermore, competitive conditions may be substantially affected by various forms of energy legislation and/or regulation considered from time to time by the government of the United States; however, it is not possible to predict the nature of any such legislation or regulation that may ultimately be adopted or its effects upon our future operations. Such laws and regulations may, however, substantially increase the costs of exploring for, developing or producing gas and crude oil and may prevent or delay the commencement or continuation of a given operation. The effect of these risks cannot be accurately predicted.

Title to Properties

We believe we have satisfactory title to all of our producing properties in accordance with standards generally accepted in the oil and gas industry. Our properties are subject to customary royalty interests, liens incident to operating agreements, liens for current taxes and other burdens, which we believe do not materially interfere with the use of or affect the value of such properties. As is customary in the industry in the case of undeveloped properties, little investigation of record title is made at the time of acquisition (other than a preliminary review of local records). Detailed investigations, including a title opinion rendered by a licensed attorney, are typically made before commencement of drilling operations.

We have granted mortgage liens on substantially all of our crude oil and natural gas properties to secure our revolving credit facility and second lien term loan agreement. These mortgages and the credit facilities contain substantial restrictions and operating covenants that are customarily found in loan agreements of this type. See Management s Discussion and Analysis of Financial Condition and

Table of Contents

Results of Operations Liquidity and Capital Resources Capital resources and Covenant compliance.

Government Regulation and Industry Matters

Federal and State Regulatory Requirements

We are a public company subject to the rules and regulations of the SEC. Recently enacted and proposed changes in the laws and regulations affecting public companies, including the provisions of the Sarbanes-Oxley Act of 2002 and rules adopted by the SEC, have resulted in increased costs to us. The new rules could make it more difficult for us to obtain certain types of insurance, including director and officer liability insurance, and we may be forced to accept reduced policy limits and coverage or incur substantially higher costs to obtain the same or similar coverage. The impact of these events could also make it more difficult for us to attract and retain qualified persons to serve on our board of directors, our board committees or as executive officers.

Our operations are subject to numerous laws and regulations governing the operation and maintenance of our facilities and the release of materials into the environment or otherwise relating to environmental protection. These laws and regulations may require that we acquire permits before commencing drilling; restrict the substances that can be released into the environment in connection with drilling and production activities; limit or prohibit drilling activities on protected areas such as wetlands or wilderness areas; or require remedial measures to mitigate pollution from current or former operations. Under these laws and regulations, we could be liable for personal injury and clean-up costs and other environmental and property damages, as well as administrative, civil and criminal penalties. These laws and regulations have been changed frequently in the past. In general, these changes have imposed more stringent requirements that increase operating costs or require capital expenditures in order to remain in compliance. It is also possible that unanticipated developments could cause us to make environmental expenditures that are significantly different from those we currently expect. Existing laws and regulations could be changed or reinterpreted, and any such changes or interpretations could have an adverse effect on our business.

Industry Regulations

The availability of a ready market for natural gas, crude oil and natural gas liquids production depends upon numerous factors beyond our control. These factors include regulation of natural gas, crude oil and natural gas liquids production, federal and state regulations governing environmental quality and pollution control, state limits on allowable rates of production by well or proration unit, the amount of natural gas, crude oil and natural gas liquids available for sale, the availability of adequate pipeline and other transportation and processing facilities and the marketing of competitive fuels. For example, a productive natural gas well may be shut-in because of an oversupply of natural gas or lack of an available natural gas pipeline in the areas in which we may conduct operations. State and federal regulations generally are intended to prevent waste of natural gas, crude oil and natural gas liquids, protect rights to produce natural gas, crude oil and natural gas liquids between owners in a common reservoir, control the amount of natural gas, crude oil and natural gas liquids produced by assigning allowable rates of production and control contamination of the environment. Pipelines are subject to the jurisdiction of various federal, state and local agencies. We are also subject to changing and extensive tax laws, the effects of which cannot be predicted. The following discussion summarizes the regulation of the United States oil and gas industry. We believe that we are in substantial compliance with the various statutes, rules, regulations and governmental orders to which our operations may be subject, although there can be no assurance that this is or will remain the case. Moreover, such statutes, rules, regulations and government orders may be changed or reinterpreted from time to time in response to economic or political conditions, and there can be no assurance that such changes or reinterpretations will not materially adversely affect our results of operations and financial condition. The following discussion is not intended to constitute a complete discussion of the various statutes, rules, regulations and governmental orders to which our operations may be subject.

Regulation of Natural Gas, Crude Oil and Natural Gas Liquids Exploration and Production

Our operations are subject to various types of regulation at the federal, state and local levels. Such regulation includes requiring permits for the drilling of wells, maintaining bonding requirements in order to drill or operate wells and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, the plugging and abandoning of wells and the disposal of fluids used in connection with operations. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units and the density of wells that may be drilled in and the unitization or pooling of crude oil and natural gas properties. In this regard, some states allow the forced pooling or integration of tracts to facilitate exploration while other states rely primarily or exclusively on voluntary pooling of lands and leases. In areas where pooling is voluntary, it may be more difficult to form units, and therefore more difficult to develop a project, if the operator owns less than 100% of the leasehold. In addition, state conservation laws which establish maximum rates of production from crude oil and natural gas wells, generally prohibit the venting or flaring of natural gas and impose certain requirements regarding the ratability of production. The effect of these regulations may limit the amount of natural gas, crude oil and natural gas liquids we can produce from our wells and may limit the number of wells or the locations at which we can drill. The regulatory burden on the oil and gas industry increases our costs of doing business and, consequently, affects our profitability. Inasmuch as such laws and regulations are frequently expanded, amended and interpreted, we are unable to predict the future cost or impact of complying with such regulations.

Regulation of Sales and Transportation of Natural Gas

Federal legislation and regulatory controls have historically affected the price of natural gas produced by us, and the manner in which such production is transported and marketed. Under the Natural Gas Act, or NGA, of 1938, the Federal Energy Regulatory Commission, or the FERC, regulates the interstate transportation and the sale in interstate commerce for resale of natural gas. Effective January 1, 1993, the Natural Gas Wellhead Decontrol Act, or the Decontrol Act, deregulated natural gas prices for all first sales of natural gas, including all sales by us of our own production. As a result, all of our domestically produced natural gas may now be sold at market prices, subject to the terms of any private contracts that may be in effect. However, the Decontrol Act did not affect the FERC s jurisdiction over natural gas transportation.

Under the provisions of the Energy Policy Act of 2005, or the 2005 Act, the NGA has been amended to prohibit market manipulation by any person, including marketers, in connection with the purchase or sale of natural gas, and the FERC has issued regulations to implement this prohibition. The Commodity Futures Trading Commission, or CFTC, also holds authority to monitor certain segments of the physical and futures energy commodities market including oil and natural gas. With regard to physical purchases and sales of natural gas and other energy commodities, and any related hedging activities that we undertake, we are thus required to observe anti-market manipulation laws and related regulations enforced by FERC and/or the CFTC. These agencies hold substantial enforcement authority, including the ability to assess civil penalties of up to $1 million per day per violation.

Under the 2005 Act, the FERC has also established regulations that are intended to increase natural gas pricing transparency through, among other things, new reporting requirements and expanded dissemination of information about the availability and prices of gas sold. To the extent that we enter into transportation contracts with interstate pipelines that are subject to FERC regulation, we are subject to FERC requirements related to use of such interstate capacity. Any failure on our part to comply with the FERC s regulations or an interstate pipeline s tariff could result in the imposition of civil and criminal penalties.

Our natural gas sales are affected by intrastate and interstate gas transportation regulation. Following the Congressional passage of the Natural Gas Policy Act of 1978, or the NGPA, the FERC adopted a series of regulatory changes that have significantly altered the transportation and marketing of natural gas. Beginning with the adoption of Order No. 436, issued in October 1985, the FERC has implemented a series of major restructuring orders that have required pipelines, among other things, to perform open access transportation of gas for others, unbundle their sales and transportation functions, and allow shippers to release their unneeded capacity temporarily and permanently to other shippers. As a result of these changes, sellers and buyers of gas have gained direct access to the particular pipeline services they need and are better able to conduct business with a larger number of counterparties. We believe these changes generally have improved our access to markets while, at the same time, substantially increasing competition in the natural gas marketplace. It remains to be seen, however, what effect the FERC s other activities will have on access to markets, the fostering of competition and the cost of doing business. We cannot predict what new or different regulations the FERC and other regulatory agencies may adopt, or what effect subsequent regulations may have on our activities. We do not believe that we will be affected by any such new or different regulations materially differently than any other seller of natural gas with which we compete.

In the past, Congress has been very active in the area of gas regulation. However, as discussed above, the more recent trend has been in favor of deregulation, or lighter handed regulation, and the promotion of competition in the gas industry. There regularly are other legislative proposals pending in the Federal and state legislatures that, if enacted, would significantly affect the petroleum industry. At the present time, it is impossible to predict what proposals, if any, might actually be enacted by Congress or the various state legislatures and what effect, if any, such proposals might have on us. Similarly, and despite the trend toward federal deregulation of the natural gas industry, we cannot predict whether or to what extent that trend will continue, or what the ultimate effect will be on our sales of gas. Again, we do not believe that we will be affected by any such new legislative proposals materially differently than any other seller of natural gas with which we compete.

Oil Price Controls and Transportation Rates

Sales prices of crude oil, condensate and gas liquids by us are not currently regulated and are made at market prices. Our sales of these commodities are, however, subject to laws and to regulations issued by the Federal Trade Commission, or the FTC, prohibiting manipulative or fraudulent conduct in the wholesale petroleum market. The FTC holds substantial enforcement authority under these regulations, including the ability to assess civil penalties of up to $1 million per day per violation. Our sales of these commodities, and any related hedging activities, are also subject to CFTC oversight as discussed above.

The price we receive from the sale of these products may be affected by the cost of transporting the products to market. Much of the transportation is through interstate common carrier pipelines. Effective as of January 1, 1995, the FERC implemented regulations generally grandfathering all previously approved interstate transportation rates and establishing an indexing system for those rates by which adjustments are made annually based on the rate of inflation, subject to certain conditions and limitations. The FERC s regulation of crude oil transportation rates may tend to increase the cost of transporting crude oil and natural gas liquids by interstate pipelines, although the annual adjustments may result in decreased rates in a given year. Every five years, the FERC must examine the relationship between the annual change in the applicable index and the actual cost changes experienced in the oil pipeline industry. In March 2006, to implement the second of the required five-yearly re-determinations, the FERC established an upward adjustment in the index to track oil pipeline cost changes. The FERC determined that the Producer Price Index for Finished Goods plus 1.3 percent (PPI plus 1.3 percent) should be the oil pricing index for the five-year period beginning July 1, 2006. We are not able at this time to predict the effects of these regulations or FERC proceedings, if any, on the transportation costs associated with crude oil production from our crude oil producing operations.

Environmental Regulations

Various federal, state and local authorities regulate our operations with regard to air and water quality, release of substances and other environmental matters. These laws and regulations may

Table of Contents

require the acquisition of a permit before drilling commences, restrict the types, quantities and concentration of various substances that can be released into the environment in connection with drilling and production activities, limit or prohibit drilling activities on certain lands within wilderness, wetlands and other protected areas, require remedial measures to mitigate pollution from current or former operations, such as pit closure and plugging abandoned wells, and impose substantial liabilities for pollution resulting from production and drilling operations. In addition, various laws and regulations require that well, pipeline, and facility sites be abandoned and reclaimed. Public interest in the protection of the environment has increased dramatically in recent years. The trend of more expansive and stringent environmental legislation and regulations applied to the crude oil and natural gas industry could continue, resulting in increased costs of doing business and consequently affecting profitability. To the extent laws are enacted or other governmental action is taken that restricts drilling or imposes more stringent and costly operating, waste handling, disposal and cleanup requirements, our business and prospects could be adversely affected.

We generate wastes that may be subject to the federal Resource Conservation and Recovery Act, as amended, or the RCRA, and comparable state statutes. The U.S. Environmental Protection Agency, or the EPA, and various state agencies have limited the approved methods of disposal for certain hazardous and nonhazardous wastes. Furthermore, certain wastes generated by our crude oil and natural gas operations that are currently exempt from treatment as hazardous wastes may in the future be designated as hazardous wastes, and therefore be subject to more rigorous and costly operating and disposal requirements.

We currently own or lease numerous properties that for many years have been used for the exploration and production of crude oil and natural gas. Although we believe that we have used good operating and waste disposal practices, prior owners and operators of these properties may not have used similar practices, and hydrocarbons or wastes may have been disposed of or released on or under the properties owned or leased by us or on or under locations where such wastes have been taken for recycling or disposal. In addition, many of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or wastes was not under our control. These properties and the wastes disposed thereon may be subject to the Comprehensive Environmental Response, Compensation and Liability Act, as amended, or the CERCLA, RCRA and analogous state laws as well as state laws governing the management of crude oil and natural gas wastes. Under such laws, which impose strict, joint and several liability, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators) or property contamination (including groundwater contamination) or to perform remedial plugging operations to prevent future contamination.

Our operations may be subject to the Clean Air Act, as amended, or the CAA, and comparable state and local requirements. Amendments to the CAA adopted in 1990 contain provisions that have resulted in the gradual imposition of pollution control requirements with respect to air emissions from our operations. The EPA and states developed and continue to develop regulations to implement these requirements. We may be required to incur capital expenditures in the next several years for air pollution control equipment in connection with maintaining or obtaining operating permits and approvals addressing other air emission-related issues. However, we do not believe our operations will be materially adversely affected by any such requirements.

In June 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act of 2009, also known as the Waxman-Markey Bill, which would establish an economy-wide cap-and-trade program to reduce greenhouse gas emissions, including carbon dioxide and methane by 17 percent from 2005 levels by the year 2020 and 80 percent by the year 2050. The U.S. Senate is considering a number of comparable measures. One such measure, the Clean Energy Jobs and American Power Act, or the Boxer-Kerry Bill, has been reported out of the Senate Committee on Energy and Natural Resources, but has not yet been considered by the full Senate and also includes a cap-and-trade system for controlling greenhouse gas emissions in the United States. Under such system, certain sources of greenhouse gas emissions would be required to obtain greenhouse gas

87

emission allowances corresponding to their annual emissions of greenhouse gases. The number of emission allowances issued each year would decline as necessary to meet overall emission reduction goals. As the number of greenhouse gas emission allowances declines each year, the cost or value of allowances is expected to escalate significantly. The ultimate outcome of these bills remains uncertain, and such bills would have to undergo reconciliation before being adopted as law. Any laws or regulations that may be adopted to restrict or reduce emissions of U.S. greenhouse gases could require us to incur increased operating costs, and could have an adverse affect on demand for the oil and natural gas we produce. In addition, at least 20 states have already taken legal measures to control emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. In California, for example, the California Global Warming Solutions Act of 2006 requires the California Air Resources Board to adopt regulations by 2012 that will achieve an overall reduction in greenhouse gas emissions from all sources in California of 25% by 2020.

Depending on the particular program, we could be required to purchase and surrender allowances, either for greenhouse gas emissions resulting from our operations or from combustion of crude oil or natural gas we produce. Although we would not be impacted to a greater degree than other similarly situated producers of natural gas, crude oil and natural gas liquids, a stringent greenhouse gas control program could have an adverse effect on our cost of doing business and could reduce demand for the crude oil and natural gas we produce.

On April 2, 2007, the United States Supreme Court found that the EPA has the authority to regulate carbon dioxide, or CO_2, emissions from automobiles as air pollutants under the CAA. Although this decision did not address CO_2 emissions from electric generating plants, the EPA has similar authority under the CAA to regulate air pollutants from those and other facilities. On April 17, 2009, the EPA released a Proposed Endangerment and Cause or Contribute Findings for Greenhouse Gases under the Clean Air Act. The EPA s proposed finding concludes that the atmospheric concentrations of several key greenhouse gases threaten the health and welfare of future generations and that the combined emissions of these gases by motor vehicles contribute to the atmospheric concentrations of these key greenhouse gases and hence to the threat of climate change. On September 15, 2009, EPA proposed a rule in anticipation of finalizing its findings to reduce emissions of greenhouse gases from motor vehicles, which rule is expected to be adopted in March 2010. Additionally, while the EPA s proposed findings do not specifically address stationary sources, those findings, if finalized, would be expected to support the establishment of future emission requirements by the EPA for stationary sources. On September 23, 2009, the EPA finalized a greenhouse gas reporting rule establishing a national greenhouse gas emissions collection and reporting program. The EPA rules will require covered entities to measure greenhouse gas emissions commencing in 2010 and submit reports commencing in 2011. On September 30, 2009, EPA proposed new thresholds for greenhouse gas emissions that define when Clean Air Act permits under the New Source Review, or NSR, and Title V operating permits programs would be required. Under the Title V operating permits program, EPA is proposing a major source emissions applicability threshold of 25,000 tons per year (tpy) of carbon dioxide CO_2e (carbon dioxide equivalency) for existing industrial facilities. Facilities with greenhouse gas emissions below this threshold would not be required to obtain an operating permit. Under the Prevention of Significant Deterioration, or PSD, portion of NSR, EPA is proposing a major stationary source threshold of 25,000 tpy CO_2e. This threshold level would be used to determine if a new facility or a major modification at an existing facility would trigger PSD permitting requirements. EPA is also proposing a significance level between 10,000 and 25,000 tpy CO_2e. Existing major sources making modifications that result in an increase of emissions above the significance level would be required to obtain a PSD permit. EPA is requesting comment on a range of values in this proposal, with the intent of selecting a single value for the greenhouse gas significance level. These proposals, along with new federal or state restrictions on emissions of carbon dioxide that may be imposed in areas of the United States in which we conduct business could also adversely affect our cost of doing business and demand for the crude oil and natural gas we produce.

Table of Contents

The U.S. Senate and House of Representatives are currently considering bills entitled, the Fracturing Responsibility and Awareness of Chemicals Act, or the FRAC Act, to amend the federal Safe Drinking Water Act, or the SDWA, to repeal an exemption from regulation for hydraulic fracturing. If enacted, the FRAC Act 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. The FRAC Act also proposes to require the reporting and public disclosure of chemicals used in the fracturing process, which could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. Although the legislation is still being developed, we do not expect the FRAC Act to have a material affect on our business because the Company contracts out all of its hydraulic fracturing work due to the specialized nature of the activity and the extensive capital investment required.

Federal regulations require certain owners or operators of facilities that store or otherwise handle crude oil to prepare and implement spill prevention, control, and countermeasure, or the SPCC, and response plans relating to the possible discharge of crude oil into surface waters. SPCC plans at our producing properties were developed and implemented in 1999. In December 2008, EPA amended the SPCC rule. On November 5, 2009, EPA signed a notice amending certain requirements of the SPCC regulations to address concerns from the regulatory community raised since the release of the December 2008 amendments. The new SPCC rule is expected to be effective January 14, 2010. Although EPA has not yet issued a final notice containing the new rules, it is clear that there will be changes impacting oil production facilities. These changes should not have a material adverse effect on us. The Oil Pollution Act of 1990, as amended, or the OPA, contains numerous requirements relating to the prevention of and response to oil spills into waters of the United States. The OPA subjects owners of facilities to strict, joint and several liability for all containment and cleanup costs and certain other damages arising from a spill, including, but not limited to, the costs of responding to a release of oil to surface waters. Noncompliance with OPA may result in varying civil and criminal penalties and liabilities. Our operations are also subject to the federal Clean Water Act, as amended, or the CWA, and analogous state laws. In accordance with the CWA, the state of Louisiana has issued regulations prohibiting discharges of produced water in state coastal waters effective July 1, 1997. Like OPA, the CWA and analogous state laws relating to the control of water pollution provide varying civil and criminal penalties and liabilities for releases of petroleum or its derivatives into surface waters or into the ground.

CERCLA, also known as the Superfund law, and similar state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of potentially responsible persons that are considered to have contributed to the release of a hazardous substance into the environment. These potentially responsible persons include the owner or operator of the disposal site or sites where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Persons who are or were 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 that have been released into the environment, for damages to natural resources and for the costs of certain health studies, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

We also are subject to a variety of federal, state and local permitting and registration requirements relating to protection of the environment. Our management believes that we are in substantial compliance with current applicable environmental laws and regulations and that continued compliance with existing requirements would not have a material adverse effect on us.

Table of Contents

Employees

At September 30, 2009, we had 73 full time employees, of whom 23 were field personnel and seven were geoscientists. We have been able to attract a talented team of industry professionals from other industry peers that have been successful in achieving significant growth and success in the past. As such, we are well-positioned to adequately manage and develop our existing assets, and also to increase our proved reserves and production through acquisitions. None of our employees are covered by collective bargaining agreements. We believe our relationship with our employees is good.

Insurance Matters

As is common in the oil and gas industry, we will not insure fully against all risks associated with our business either because such insurance is not available or because premium costs are considered prohibitive. A loss not fully covered by insurance could have a materially adverse effect on our financial position, results of operations or cash flows.

Legal Proceedings

From time to time, we are involved in litigation relating to claims arising out of our operations or from disputes with vendors in the normal course of business. During the second quarter of 2009, holders of oil and gas leases in East Texas (Haynesville Shale) filed two causes of action against us alleging breach of contract for not paying lease bonuses on certain oil and gas leases taken by our leasing agent. The damages alleged are approximately $2.8 million and there are approximately $300,000 in written demands from other holders of leases in this area that we believe may contemplate legal proceedings. We are vigorously defending these lawsuits, and believe we have meritorious defenses. We do not believe that these claims will have a material adverse affect on our business, financial position, results of operations or cash flows, although we cannot guarantee that a material adverse effect will not occur.

Offices

We currently sublease, through January 31, 2014, 54,939 square feet of executive and corporate office space located at 717 Texas Avenue in downtown Houston, Texas. Rent, including parking, related to this office space for the nine months ended September 30, 2009 was approximately $1.3 million.

MANAGEMENT

Executive Officers and Directors

Our executive officers and directors as of the date of this prospectus are as follows. Each is a citizen of the U.S. unless otherwise indicated.

Name	Age	Position
Allan D. Keel	49	President, Chief Executive Officer and Director
E. Joseph Grady	56	Senior Vice President and Chief Financial Officer
Tracy Price	51	Senior Vice President Land/Business Development
Thomas H. Atkins	51	Senior Vice President Exploration
Jay S. Mengle	55	Senior Vice President Engineering
B. James Ford	41	Director
Adam C. Pierce	31	Director
Lee B. Backsen	69	Director
Lon McCain	61	Director
Cassidy J. Traub	28	Director

Allan D. Keel was appointed Chief Executive Officer and President and joined the Company s Board of Directors, or Board, on February 28, 2005. Before joining Crimson, Mr. Keel was Vice President/General Manager of Westport Resources, Houston office, during 2004. In this role he was responsible for its Gulf of Mexico operations including acquisitions, development and exploration. In 2003, Mr. Keel served as a consultant to both domestic and international companies in building their presence in the Gulf of Mexico. From mid-2000 until mid-2001, Mr. Keel served as a Vice President at Enron Energy Finance where he worked on private equity transactions and volumetric production payments. From mid-2001 through 2002, Mr. Keel served as President and CEO of Mariner Energy Company (Mariner), a majority owned affiliate of Enron. Subsequent to Enron s bankruptcy and its decision to sell Mariner, Mr. Keel partnered with Oaktree Capital Management in an effort to acquire Mariner. From 1996 until mid-2000, Mr. Keel was Vice President/General Manager for Westport Resources, where he built the Gulf of Mexico division from the grassroots. From 1984 to 1996, Mr. Keel was with Energen Resources where he directed the company s exploration, joint venture and acquisition activities. Mr. Keel was appointed pursuant to the terms of the Series G Preferred Stock. He received a Bachelor of Science degree and a Master of Science degree in Geology from the University of Alabama and a Masters of Business Administration degree from the Owen School of Management at Vanderbilt University.

E. Joseph Grady was appointed Senior Vice President and Chief Financial Officer on February 28, 2005. Mr. Grady is managing director of Vision Fund Advisors, Inc., a financial advisory firm he co-founded in 2001, and serves as an advisor to the board for the firm s privately-held investment and advisory clients. Mr. Grady has over 30 years of financial, operational and administrative experience, including over 20 years in the oil and gas industry. He was formerly Senior Vice President Finance and Chief Financial Officer of Texas Petrochemicals Holdings, Inc. from April 2003 to July 2004, Vice President-Chief Financial Officer and Treasurer of Forcenergy Inc. from 1995 to 2001 and held various financial management positions with Pelto Oil Company from 1980 to 1990, including Vice President-Finance from 1988 to 1990. Mr. Grady received a Bachelor of Science degree in Accounting from Louisiana State University.

Tracy Price was appointed Senior Vice President Land/Business Development on April 1, 2005. Mr. Price joined the Company after serving as the Senior Vice President- Land/Business Development for The Houston Exploration Company from 2001 until joining the Company. Prior to his tenure at The Houston Exploration Company, Mr. Price served as Manager of Land and Business Development for Newfield Exploration Company between 1990 and 2001. From 1986 to 1990 Mr. Price was Land Manager for Apache Corporation. Prior to Apache, Mr. Price served in similar land management capacities at Challenger Minerals Inc. and Phillips Petroleum Company. Mr. Price received a Bachelor of Business Administration degree in Petroleum Land Management from the University of Texas.

Thomas H. Atkins was appointed Senior Vice President Exploration on April 1, 2005. Mr. Atkins joined the Company after serving as the General Manager Gulf of Mexico for Newfield Exploration Company where he was employed from 1998 until joining the Company. Prior to his tenure at Newfield, Mr. Atkins served in various exploration capacities with EOG Resources and its predecessor companies from 1984 to 1998, including prospect generator, development geologist and finally as Exploration Manager. Mr. Atkins also worked at the Superior Oil Company from 1981 through 1984. Mr. Atkins received a Bachelor of Science degree in Geology from the University of Oklahoma.

Jay S. Mengle was appointed Senior Vice President Operations and Engineering on April 1, 2005, after serving as the Shelf Asset Manager Gulf of Mexico for Kerr-McGee Corporation subsequent to its 2004 merger with Westport Resources. Mr. Mengle was with Westport Resources from 1998 to 2004, where he started Westport s Gulf Coast/Gulf of Mexico drilling and production operations. Prior to joining Westport, Mr. Mengle also served in various drilling, production and marketing management capacities at Norcen Energy Resources, Kirby Exploration and Mobil Oil Corp. Mr. Mengle received his Bachelor of Science degree in Petroleum Engineering from the University of Texas.

B. James Ford became a member of the Company s Board on February 28, 2005. Mr. Ford is a Co-Portfolio Manager and Managing Director of Oaktree Capital Management, an affiliate of Oaktree Holdings. Before joining Oaktree Capital Management in June 1996, Mr. Ford was a consultant with McKinsey & Co., and a financial analyst in the Investment Banking Department of PaineWebber Incorporated. He currently serves as a director of EXCO, Cequel Holdings, Fu Sheng Industrial Co., Ltd., GAP Broadcasting Group, LLC and Verge Media Companies, Inc. Mr. Ford also serves as an active member of the Children s Bureau Board of Directors and as trustee of the Stanford Graduate School of Business Trust. Mr. Ford was appointed pursuant to the terms of the Series G Preferred Stock, the majority of which is held by Oaktree Holdings. Mr. Ford earned a Bachelor of Arts degree in Economics from the University of California at Los Angeles and a Masters of Business Administration degree from the Stanford University Graduate School of Business.

Adam C. Pierce was appointed to the Company s Board on January 24, 2008. Mr. Pierce is a Vice President of Oaktree Capital Management, an affiliate of Oaktree Holdings. Prior to joining Oaktree Capital Management in 2003, he was an investment banker with J.P. Morgan Chase & Company. Prior to joining J.P. Morgan Chase & Co., Mr. Pierce worked for Goldman Sachs. Mr. Pierce serves on the board of directors for several privately-held companies in which Oaktree Capital Management has invested. Mr. Pierce was appointed pursuant to the terms of the Series G Preferred Stock, the majority of which is held by Oaktree Holdings. Mr. Pierce received a Bachelor of Arts degree in Economics with a focus on Business Administration from Vanderbilt University.

Lee B. Backsen became a member of the Company s Board on June 1, 2005. Mr. Backsen is an oil and gas exploration consultant with over 45 years experience in the industry holding senior exploration management positions with Burlington Resources Inc., UMC Petroleum Corporation, General Atlantic Gulf Coast Inc., Kerr-McGee Corporation, Pelto Oil Company, Spectrum Oil and Gas Company and Shell Oil Company. From 2004 to 2008, Mr. Backsen was Vice President Exploration for Andex Resources, LLC, a private oil and gas producing company, and was responsible for sourcing exploration joint ventures. From 2000 to 2004, Mr. Backsen was a consulting geologist for Continental Land & Fur Co., Inc. and Grant Geophysical, Inc., for whom he screened exploratory prospects in the Texas and Louisiana Gulf Coast Basins. Mr. Backsen earned a Bachelor of Science degree and Masters of Science degree in Geology from Iowa State University.

Lon McCain became a member of the Company s Board on June 1, 2005. Mr. McCain was Vice President, Treasurer and Chief Financial Officer of Westport Resources Corporation, a large, publicly traded exploration and production company, from 2001 until the sale of that company to Kerr-McGee

92

Table of Contents

Corporation in 2004. From 1992 until joining Westport, Mr. McCain was Senior Vice President and Principal of Petrie Parkman & Co., an investment banking firm specializing in the oil and gas industry. From 1978 until joining Petrie Parkman, Mr. McCain held senior financial management positions with Presidio Oil Company, Petro-Lewis Corporation and Ceres Capital. He currently serves as a director of Transzap Inc., Cheniere Energy Partners L.P. and Continental Resources Inc. Mr. McCain was an Adjunct Professor of Finance at the Daniels College of Business of the University of Denver from 1982 to 2004. Mr. McCain received a Bachelor of Science degree in Business Administration and a Masters of Business Administration/Finance from the University of Denver.

Cassidy J. Traub was appointed to the Company s Board on December 7, 2009. Mr. Traub is a Vice President at Oaktree Capital Management, an affiliate of Oaktree Holdings, in the Principal Group. Prior to joining Oaktree Capital Management in 2005, Mr. Traub spent over two years as an Analyst at UBS Investment Bank, where he was involved in various aspects of mergers and acquisitions, leveraged buyouts, initial public offerings and debt financings. He is currently a member of the board of directors of several private companies. Mr. Traub received an A.B. degree in Economics with an emphasis in Finance from Princeton University.

There are no family relationships between any of the executive officers or directors of Crimson Exploration.

Compensation of Directors

Name	Year	Fees Earned or Paid in Cash ($)	Stock Awards ($)(1)	Total ($)
B. James Ford(2)	2008	45,667		45,667
Lon McCain	2008	62,250	9,435	71,685
Lee B. Backsen	2008	49,667	9,435	59,102
Adam C. Pierce(2)	2008	47,667		47,667

(1) Includes the dollar amount of compensation expense we recognized for the fiscal year ended December 31, 2008. The awards for which compensation expense was recognized consist of awards granted on May 10, 2007 and July 22, 2008. The amounts above do not include awards granted on March 25, 2009 under the Plan for the 2008 service year. As of December 31, 2008, there were 10,160 shares outstanding granted pursuant to restricted stock awards to our directors.

(2) Messrs. Ford, Pierce and Baker, as employees of Oaktree Capital Management, elected not to receive stock awards during 2008, 2007 and 2006.

Upon the recommendation of the Compensation Committee, the Board approved on November 21, 2008, an amended compensation plan for non-employee directors (the Plan) providing for a $30,000 annual retainer, with a $2,000 meeting attendance fee ($1,000 if by telephone) for each full board, Audit and Compensation Committee meeting. The chairman of the Audit and Compensation Committee is entitled to receive an annual retainer of $13,500 and $6,000, respectively. The amended board compensation plan was effective June 1, 2008, which was the beginning of the 2008-2009 board year.

Under the Plan, each non-employee director receives $50,000 of restricted common stock for his first year of service subject to a three-year vesting schedule. Upon re-election, each non-employee director receives $50,000 in restricted common stock, subject to a one-year vesting requirement. The number of shares to be awarded is determined based on the fair market value of our common stock as of the close of trading on the date of grant.

The Plan replaced the previous director compensation plan for non-employee directors, which had been approved on June 1, 2005 and was in effect until May 31, 2008. Under the previous plan, non-employee directors were entitled to a $10,000 annual retainer, with a $2,000 meeting attendance fee ($1,000 if by telephone) for a maximum of $8,000 per director per year, with an additional fee

Table of Contents

payable for attendance of committee meetings held on days other than those on which the Board meets. The chairman of each of the Audit Committee and the Compensation Committee was also entitled to receive an annual retainer of $5,000 and $2,500, respectively.

In addition, the Plan provides for reimbursement of expenses for all directors in the performance of their duties, including reasonable travel expenses incurred attending meetings. Employee directors are not paid additional compensation for serving as a director.

Board Composition

Under our certificate of incorporation and bylaws, the number of directors at any one time are set by resolution of the Board. Currently, the Board consists of six members, five of whom we expect will qualify as independent under the NASDAQ Stock Market Rules. In connection with this offering, the Board has acted by resolution to increase the total number of directors to six and appointed one additional director, Mr. Traub, who we expect will qualify as independent under the NASDAQ Stock Market Rules and Rule 10A-3(b)(1) under the Exchange Act to fill that vacancy. In connection with this appointment, Oaktree Holdings, as the majority holder of the Series G Preferred Stock, has permitted the total number of directors elected by the holders of the Series G Preferred Stock to equal 50% of the total number of directors, but has reserved the right to increase the number of Series G Preferred Stock director appointees until the conversion of all the Series G Preferred Stock.

The Board has reviewed the independence of the members of the Board of Directors in accordance with the guidelines set out in Rule 5605(a)(2) of the NASDAQ Stock Market Rules. As a result of the review, the Board has determined that Messrs. Backsen, Ford, McCain, Pierce and Traub each will qualify as independent directors upon the consummation of this offering in accordance with Rule 5605(a)(2). In making its independence determinations, the Board noted in particular the following:

Mr. Ford is a managing director, Mr. Pierce is a vice president and Mr. Traub is a vice president of Oaktree Capital Management, an affiliate of Oaktree Holdings.

Oaktree Holdings and OCM Crimson together beneficially own 8,427,884 shares of our common stock, including 76,710 shares of our Series G Preferred Stock, and Oaktree Holdings beneficially owns 2,000 shares of our Series H Preferred Stock, and after completion of this offering Oaktree Holdings and OCM Crimson will continue to own a significant number of shares of our common stock.

Oaktree Holdings is the payee of an unsecured subordinated promissory note made by the Company in the aggregate principal amount of $2.0 million.

An affiliate of Oaktree Holdings is a holder of a significant amount of debt under our second lien term loan agreement that it acquired in the secondary market from unaffiliated third parties.

The Board noted that The NASDAQ Stock Market LLC (NASDAQ) does not view ownership of even a significant amount of stock, by itself, as a bar to an independence finding. The Board also noted that Oaktree Capital Management is comprised of nine principals and approximately 580 employees with offices in 14 cities worldwide, has its headquarters in Los Angeles and has over $60 billion in assets under management. The Board determined that none of the above factors caused any of Messrs. Ford, Pierce or Traub to have a relationship with the Company that would impair their independence for the purposes of Rule 5605(a)(2).

Our certificate of incorporation and bylaws provide for the annual election of directors. At each annual meeting of stockholders, our directors will be elected for a one-year term and serve until their respective successors have been elected and qualified. It is anticipated that the Board of Directors will meet at least quarterly.

Table of Contents

The Board held six meetings during 2008. No director during the last fiscal year attended fewer than 75% of the total number of meetings of the Board and committees on which that director served.

Stockholders desiring to communicate with the Board may do so by mail addressed as follows: Board of Directors, Crimson Exploration Inc., 717 Texas Avenue, Suite 2900, Houston, Texas 77002. We believe our responsiveness to stockholder communications to the Board has been excellent.

The Company encourages, but does not require, directors to attend annual meetings of stockholders. At the Company s 2008 stockholder meeting, all members of the Board at the time of the meeting attended.

Board Committees

The Board has the authority to appoint committees to perform certain management and administrative functions. The Board has established a Compensation Committee, an Audit Committee and, a Corporate Governance and Nominating Committee. Following completion of this offering, the Audit Committee will have three members and each of the Compensation Committee and Corporate Governance and Nominating Committee will have three members, all of whom will qualify as independent under the rules and regulations of the SEC and NASDAQ.

Audit Committee

The Audit Committee was established to review and appraise the audit efforts of our independent accountants, and monitor our accounts, procedures and internal controls. During 2008, the Audit Committee consisted of Mr. McCain and Mr. Pierce. Mr. Pierce replaced Mr. Skardon F. Baker, who served on the Audit Committee until his resignation from the Board on January 24, 2008. Mr. Traub was appointed to serve on our Audit Committee on December 7, 2009. The Audit Committee met four times in 2008. The Board has determined that Mr. McCain is an audit committee financial expert as defined under applicable rules and regulations of the SEC. Our Audit Committee has adopted a charter, which is posted on our website www.crimsonexploration.com under Corporate Governance.

Compensation Committee

The function of the Compensation Committee is to recommend for approval by the Board the annual salaries and other compensation for our executive officers and key employees. Our Compensation Committee consists of Messrs. Ford and Backsen. The committee met three times in 2008. Our Compensation Committee has adopted a written charter, which is posted on our website www.crimsonexploration.com under Corporate Governance. The Compensation Committee has the following authority and responsibilities:

- To establish and review our overall compensation philosophy;
- To review and approve corporate goals and objectives relevant to our executive officers compensation, evaluate the performance of such officers and recommend for approval by the Board, the benefits, direct and indirect, of our executive officers based on this evaluation;
- To review and recommend to the Board for approval all our equity compensation plans that are not otherwise subject to the approval of the stockholders;
- To review and make recommendations to the Board for approval of all equity awards;
- To review and monitor all employee pension, profit-sharing and benefit plans, if any; and

To make recommendations to the Board with regard to our compensation and benefit programs and practices for all employees.

While the Compensation Committee is not prohibited from delegating its functions, the Compensation Committee has not done so in the past, although it may consider senior management s

95

recommendations regarding appropriate compensation for members of management reporting to them, as discussed under Compensation Discussion and Analysis below.

Corporate Governance and Nominating Committee

Prior to this offering the Board did not have a Corporate Governance and Nominating Committee and the functions of this committee were performed by the whole Board. In connection with this offering, the Board of Directors has appointed Messrs. Ford, Backsen and McCain to serve as the members of the Corporate Governance and Nominating Committee. The Corporate Governance and Nominating Committee will identify and recommend nominees to the Board of Directors and oversee compliance with our corporate governance guidelines. Prior to the completion of this offering the Corporate Governance and Nominating Committee will adopt a written charter addressing director nominations and post a copy on our website www.crimsonexploration.com under Corporate Governance.

The Board believes that candidates for director should have certain minimum qualifications, including being able to read and understand financial statements and having the highest personal integrity and ethics. Previously the Board has, and after this offering the Corporate Governance and Nominating Committee will, consider such factors as relevant expertise and experience, ability to devote sufficient time to the affairs of the Company, demonstrated excellence in his or her field, the ability to exercise sound business judgment and the commitment to rigorously represent the long-term interests of the Company s stockholders. Candidates for director will be reviewed in the context of the current composition of the Board, the operating requirements of the Company and the long-term interests of stockholders.

The Board currently does not, and immediately following this offering the Corporate Governance and Nominating Committee will not, have a formal process in place for identifying and evaluating nominees for directors. Instead, the Corporate Governance and Nominating Committee will use its network of contacts to identify potential candidates. The Corporate Governance and Nominating Committee will conduct any appropriate and necessary inquiries into the backgrounds and qualifications of possible candidates after considering the function and needs of the Board. The Corporate Governance and Nominating Committee will meet to discuss and consider such candidates qualifications and then select a nominee for recommendation to the Board by a majority vote.

The Board has not established procedures for considering nominees recommended by stockholders. The Board believes that nominees should be considered on a case-by-case basis on each nominee s merits, regardless of who recommended such nominee.

Compensation Committee Interlocks and Insider Participation

None of our executive officers serves, or has served during the past fiscal year, as a member of the board of directors or compensation committee of any other company that has one or more executives serving as a member of our board of directors or compensation committee.

Code of Ethics

We have adopted a code of ethics as defined by the applicable rules of the SEC, and it has been posted on our website at www.crimsonexploration.com.

EXECUTIVE COMPENSATION AND OTHER INFORMATION

Compensation Discussion and Analysis

The following Compensation Discussion and Analysis contains statements regarding future individual and company performance targets and goals. These targets and goals are disclosed in the limited context of our executive compensation program and should not be understood to be statements of management s expectations or estimates of results or other guidance. We specifically caution stockholders not to apply these statements to other contexts.

Introduction

This Compensation Discussion and Analysis (1) provides an overview of our compensation policies and programs; (2) explains our compensation objectives, policies and practices with respect to our executive officers; and (3) identifies the elements of compensation for each of the individuals identified in the following table, whom we refer to in this Compensation Discussion and Analysis as our named executive officers.

Name	Principal Position
Allan D. Keel	Chief Executive Officer and President
E. Joseph Grady	Senior Vice President and Chief Financial Officer
Tracy Price	Senior Vice President Land/Business Development
Jay S. Mengle	Senior Vice President Operations and Engineering
Thomas H. Atkins	Senior Vice President Exploration

Objectives and Philosophy of Our Executive Compensation Program

Due to an aging of the industry employee base, and a shortage of new entrants into the industry, competition for high-caliber personnel experienced in the oil and gas industry has become very intense. Accordingly, the objective of our compensation program is to establish a competitive compensation program with appropriate compensation packages for the wide variety of duties performed by our named executive officers. In addition, we have sought to establish a competitive compensation program that motivates our executive officers to enhance long-term stockholder value.

Recognizing that attracting, retaining and motivating our executive officers to successfully perform demanding roles is critical to meeting our strategic business and financial goals, our compensation philosophy is that the compensation paid to our executive officers should be directly and materially linked to our achievement of our specific annual, long-term and strategic goals and to each officer s individual contribution to the attainment of those goals. We believe our overall compensation strategy of offering a balanced combination of annual and long-term compensation to our executive officers based upon corporate and individual performance helps maximize stockholder return.

To achieve these objectives, we have historically evaluated the compensation paid to our executive officers based upon the following factors:

- the appropriate mix of salary, cash incentives and equity incentives;
- company growth and financial and operational performance, as well as individual performance; and

market analysis of the compensation packages of our executive officers compared to the compensation packages of executive officers at other oil and gas industry companies that are similar to ours in their operations, among other factors.

Table of Contents

Except as otherwise noted below, we do not assign relative weights or rankings to these factors. Instead, the Compensation Committee makes subjective determinations of compensation levels based upon a consideration of all of these factors.

Setting Executive Compensation

On behalf of our Board, the Compensation Committee reviews, evaluates and approves all compensation for our executive officers, including our compensation philosophy, policies and plans. Our Chief Executive Officer and Chief Financial Officer also play important roles in the executive compensation process, including evaluating the other executive officers and assisting in the development of performance target goals. For example, at least once each year the Chief Executive Officer and Chief Financial Officer present to the Compensation Committee their evaluation of each of the other named executive officers (including, the Chief Executive Officer s evaluation of the Chief Financial Officer), which includes a review of contribution and performance over the past year, strengths, weaknesses, development plans and succession potential. Following these presentations and a review of all relevant data, the Compensation Committee makes its own assessments and recommends to the Board approval of the compensation for each named executive officer. Although the Chief Executive Officer and the Chief Financial Officer each may make recommendations to the Compensation Committee regarding his own compensation, to the extent events or circumstances are applicable to all named executive officers as a group regarding compensation decisions, all final decisions regarding executive compensation remain with the Compensation Committee or our Board. In this way all compensation elements are reviewed and approved by the Compensation Committee or our Board. The Compensation Committee does take into consideration the named executive officers total compensation, including base salary annual incentives and long-term incentives, both cash and equity, when considering market based adjustments to the named executive officers compensation.

In January 2008, the Compensation Committee retained Longnecker & Associates, an experienced compensation consulting firm that specializes in the energy industry and that has access to national compensation surveys and our compensation information, to conduct a company-wide review of our compensation policies and programs to determine our level of competitiveness in the oil and gas industry and advise the Compensation Committee as to whether modifications should be adopted in order to attract, motivate and retain key employees. The Compensation Committee is compensated by the Company. After our acquisition of the STGC Properties from EXCO in 2007, which significantly increased the size of our company, we felt that it had become increasingly important, given our growing need for highly skilled and experienced personnel in highly competitive labor market, to take additional measures to ensure that we were appropriately compensating our key employees and rewarding performance in a manner consistent with similar employers of a similar size. Additionally, the initial terms of the employment contracts for Messrs. Keel and Grady were set to expire in 2008, and the initial terms of the employment contracts for Messrs. Price, Mengle and Atkins expired in 2007. Accordingly, for these reasons we felt that it was appropriate to engage a compensation consultant at the beginning of 2008 to assist the Compensation Committee in its compensation review. The results of that review, as well as the latest ECI surveys using data from the selected Peer Group, were utilized by the Compensation Committee in determining and modifying the executive compensation levels for fiscal 2008. The Compensation Committee determined that no changes to executive compensation levels were necessary for fiscal 2009 upon the recommendation of the Chief Executive Officer and Chief Financial Officer.

The Compensation Committee did not retain independent compensation consultants to assist it in evaluating executive compensation matters for fiscal years 2006 or 2007. Instead, the Compensation Committee made comparisons of our executive compensation program to the compensation paid to executives of other companies within the oil and gas industry. Energy industry compensation surveys from Effective Compensation Inc. (ECI) were used. ECI surveys were utilized as they are specific to the energy industry and derive their data from direct contributions from a large number of participating companies that we consider to be our peers. The ECI surveys compile data from most companies that

98

Table of Contents

we currently consider to be in our peer group, as well as companies somewhat larger than us but with which we compete for talent. The surveys were used to compare our executive compensation program against companies (the Peer Group) that have comparable market capitalization, revenues, capital expenditure budgets, geographic focus and number of employees.

With respect to compensation decisions made in 2008, the selected Peer Group for 2008 included Swift Energy Company, Comstock Resources, Inc., Continental Resources, Inc., Energy XXI, PetroQuest Energy, Inc., Concho Resources, Inc., Callon Petroleum Company, Delta Petroleum Corp., Edge Petroleum Corp., Goodrich Petroleum Corporation, Dune Energy, Inc. and Gastar Exploration Limited. The Compensation Committee regularly reviews and refines the Peer Group as appropriate. When we refer to peers, peer group or peer companies or similar phrases, we are referring to this list of companies, as it may be updated by the Compensation Committee from time to time.

The Company believes that each element of compensation has been designed to complement the other components and, when considered together, to meet the Company s compensation objectives; however, the Company does not have a policy or target for the allocation between short-term and long-term or cash and non-cash incentive compensation.

Elements of Our Executive Compensation Program

General

The principal components of our executive compensation program include:

- base salary;
- performance-based cash incentive compensation;
- discretionary cash incentive compensation;
- long-term equity-based incentive compensation;
- overriding royalty interest plan compensation;
- severance benefits; and
- other health and fringe benefits.

Base Salary

We provide base salaries to our executive officers to compensate them for services rendered during the year at levels that we believe are competitive in the oil and gas industry and that are designed to allow us to attract, motivate and retain executive officers. Base salaries are a major component of the total annual cash compensation paid to our executive officers and are reviewed annually by the Compensation Committee. Base salary determinations are made by the Board taking into consideration salary recommendations from the Compensation Committee. The Compensation Committee will consider senior management s recommendations as to appropriate compensation for members of management reporting to them.

All of our executive officers are subject to employment agreements that provide for a fixed base salary. These salaries were determined after taking into account many factors, including:

the historic salary structure within our company;

the responsibilities of the officer;

the scope, level of expertise and experience required for the officer s position;

the strategic impact of the officer s position;

- the potential future contribution and demonstrated individual performance of the officer; and
- salaries paid for comparable positions at similarly-situated companies.

At the time the employment agreements were entered into, we set base salaries at the base salary comparables at or near the 50th percentile of salaries of comparable executive officers of what we considered our peer group of companies. After a consideration of the factors described above, we did not increase the base salary levels of our named executive officers during fiscal 2006 or 2007. Subsequent changes to those initial salaries were made after consideration of our performance, individual performance and competitive salaries prevalent in the oil and gas industry. In early 2008, our Board, based on the recommendation of the Compensation Committee, approved increases to the annual base salaries of the named executive officers as follows:

Name	Former Base Salary	New Base Salary
Allan D. Keel	$ 240,000	$ 370,000
E. Joseph Grady	$ 220,000	$ 340,000
Jay S. Mengle	$ 180,000	$ 220,000
Thomas H. Atkins	$ 180,000	$ 200,000
Tracy Price	$ 185,000	$ 200,000

In addition, in 2008 our Board approved and we entered into amended and restated employment agreements with our named executive officers to reflect these base salary increases and to, among other things, modify provisions relating to the federal income tax treatment of certain arrangements in order to meet the December 31, 2008 deadline for compliance with Section 409A of the Internal Revenue Code of 1986, as amended (the Code), reflect other market-based changes in compensation approved in early 2008 by the Compensation Committee and provide for new terms of the agreements, since the initial terms of the existing employment agreements expired. This Code section governs the treatment of deferred compensation which is broadly defined and thus has the potential to impact numerous types of compensation arrangements between us and our employees. If violated, Section 409A can result in adverse tax consequences to the employee. The Section 409A amendments to our compensation arrangements were intended to prevent any such adverse tax result on our employees. See Narrative Disclosure to Summary Compensation Table and Grants of Plan Based Awards Table Employment Agreements.

Performance-Based Cash Incentive Compensation

All of our employees, including our named executive officers, are eligible to participate in an annual, performance-based cash incentive compensation plan that is designed to reward employees on the basis of our company attaining pre-determined performance measures.

The Compensation Committee annually approves the quantitative performance goals for five separate categories under the plan, usually within the first two months of the plan year. The categories are reviewed annually by the Compensation Committee with input from our executive officers and adjusted, as needed, in order to reflect our current structure and operations. For fiscal 2007 and 2008, the categories consisted of the following:

- *Oil and Gas Production Levels (Production).* The Production goal is based on targeted performance levels for the fiscal year.
- *Earnings Before Interest, Taxes, Depreciation, Amortization and Exploration Expenses (EBITDAX).* EBITDAX is a non-GAAP measure we use as an approximation of net income (loss). Our

definition of EBITDAX may differ from that of other companies and excludes Exploration (Geological & Geophysical) expenses, Exploration Dry Hole Costs (DHC) and other non-cash charges normally considered expenses by oil and gas companies utilizing successful efforts method of accounting.

Table of Contents

Replacement of Oil and Natural Gas Reserves Depleted by Production (Reserve Replacement). Reserve Replacement is a measure of our ability to replace oil and gas reserves over and above equivalent reserves depleted by oil and gas production during the fiscal year.

Finding and Development Costs (F&DC). F&DC measures the cost to locate prospects, acquire production rights, drill and complete wells and install or construct production equipment and facilities per equivalent unit of proved reserves added ($/Mcfe) during the fiscal year, inclusive of revisions of prior year reserve estimates.

Return on Invested Capital (ROIC). ROIC is a measure of earnings before taxes (but excludes certain expenses, including exploration costs and dry hole costs, non-cash equity-based compensation expenses, gains/losses from mark to market accounting on derivatives and gains/losses from asset impairment), divided by average stockholders equity for the year (consisting of the par value of our preferred stock and common stock plus additional paid-in capital).

Each performance category was selected based on the Compensation Committee s belief that it most accurately measures our corporate performance in relation to comparable oil and gas companies within our peer group.

Each year, the Compensation Committee establishes the minimum,   target and maximum performance levels for each of the five performance categories and their appropriate weighting. For each executive officer, the Compensation Committee determines the appropriate percentage allocation to be assigned for each category. In most cases, when determining an executive officer s bonus, the Compensation Committee gives equal weight to each category except when a particular performance category bears a more direct relationship to the executive officer s areas of responsibility, in which case a particular performance category may be more heavily weighted. The weighting for each named executive officer for fiscal 2007 for each of the five categories was as follows:

Category	**Mr. Keel**	**Mr. Grady**	**Mr. Price**	**Mr. Mengle**	**Mr. Atkins**
Production	20%	20%	20%	30%	10%
EBITDAX	20%	20%	20%	20%	10%
Reserve Replacement	20%	20%	20%	20%	35%
F&DC	20%	20%	20%	20%	35%
ROIC	20%	20%	20%	10%	10%

For fiscal 2008, the Compensation Committee determined weights to be assigned to each performance category, based on the importance of each category to our overall success, and applied to each executive officer equally. The weighting assigned to each performance category applicable to Messrs. Mengle and Atkins was modified for fiscal 2008 in order to better reflect the overall contribution of these officers to the performance goals of the Company for 2008. The weighting for each named executive officer for fiscal 2008 for each of the five categories is as follows:

Category	**Fiscal 2008**
Production	20%
EBITDAX	20%
Reserve Replacement	20%
F&DC	20%

ROIC	20%

Should our financial and operating results meet or exceed either the pre-determined minimum, target and maximum values assigned a particular performance category (with linear interpolations between each level), then each executive officer is paid an annual bonus that is a percentage of their annual salary. The Compensation Committee retains the right to make what it determines to be appropriate adjustments to actual results for the year, to the extent it believes that adjustments are warranted. For example, in determining the actual level of EBITDAX and ROIC for a particular year, it may exclude the effects of certain non-cash income/expense items such as the mark to market benefit/charge to our results of operations as required by GAAP and non-cash charges to our results of operations related to non-cash equity-based compensation charges for stock options or the variance in EBITDAX and ROIC caused by the variance in realized oil and gas prices compared to those incorporated into the performance goals (since prices are largely not within management s control).

For fiscal 2007, the Compensation Committee established the target bonus percentage for each executive officer after taking into account the importance of the position held by that officer to us achieving our performance goals during the year as well as published compensation surveys. The actual percentage of annual salary that was paid as an annual cash incentive bonus for 2007 ranged from 20% to 100% of the annual salaries for Messrs. Keel and Grady and from 20% to 70% of the annual salaries for Messrs. Price, Mengle and Atkins. The maximum values were originally determined at the time we entered into the employment agreements with each executive officer.

For fiscal 2008, as part of our compensation review process, the Compensation Committee in mid-2008 revised the target bonus percentage for each executive officer after taking into account Longnecker & Associates data and suggestions. As a result of this revision, the actual percentage of annual salary to be potentially paid as an annual cash incentive bonus for 2008 ranged from 50% to 120% of the annual salaries for Messrs. Keel and Grady and from 40% to 100% of the annual salaries for Messrs. Price, Mengle and Atkins. This adjustment was made so that our Performance-Based Cash Incentive Compensation Plan would be more in line with performance-based incentive plans offered to the executive officers of companies we consider to be in our peer group in our industry.

The actual percentage of annual salary potentially paid to an executive officer as a bonus is dependent upon the extent to which we meet or exceed our pre-determined performance goals. Payment of annual cash incentive bonuses to our executive officers is not guaranteed and is based upon our actual performance during the fiscal year, including meeting at least the minimum performance targets we set. Bonuses are typically paid out in cash during the first quarter of the year following the fiscal year in which they are earned, at the discretion of the Compensation Committee.

The Compensation Committee established the minimum, target and maximum performance levels (with linear interpolations between each level) for fiscal 2008 as follows:

The minimum level is equal to 80% of the target level of performance goal and is the level at which payout under the plan begins for the applicable performance measure. If the actual performance level for a measure is below the minimum level, no payout occurs with respect to that measure.

The target level is that at which 100% of the applicable performance goal is attained, and represents the expected payout level.

The maximum level is that at which 120% of the applicable target performance goal is attained.

After giving consideration to past Company performance and peer performance, the Compensation Committee set these performance levels so that the attainment of the targets is not assured and requires significant effort by our executives. We believe that the disclosure of performance targets would result in competitive harm to us and are therefore omitted since we are engaged in a highly competitive business, we may pursue opportunities in areas without first publicly disclosing our intention to do so and disclosure of these targets might enable our competitors to determine our strategic areas of interest and priorities throughout the year. We also believe that disclosure of our performance targets would undermine our on-going efforts to retain officers and other employees in a competitive employment atmosphere. Our business is highly dependent on attracting and keeping qualified, skilled employees. We believe that public disclosure of the performance targets used to determine the named executive incentive compensation would materially increase the ability of competitors to track current year bonus potential and tailor compensation packages designed to persuade officers and other employees to leave the Company. In addition, it would give our competitors an unfair informational advantage with respect to competing for prospective employees.

The Compensation Committee adjusted the minimum, target and maximum performance levels from 40%, 100% and 115% for 2007, respectively, to the current levels for 2008 because the prior performance levels were not reflective of competitive incentive compensation levels offered by the Company s industry peer group companies.

For fiscal 2008, as part of our compensation review process, our Board, upon the recommendation of our Compensation Committee revised the minimum, target and maximum performance levels (with linear interpolations between each level) as that at which 80%, 100% and 120% of the expected applicable target performance goal for each measure will occur, respectively.

In 2008, in recognition of the Company s low stock price, the Company s strategy of conserving cash to pay down debt during this low commodity price environment and the negative reserve revisions at the end of 2008, the Company s executives voluntarily waived the performance-based cash incentive compensation to which they were entitled under the plan for the 2008 fiscal year.

If the Company s executives had not voluntarily waived the performance-based cash incentive compensation to which they were entitled under the plan for the 2008 fiscal year, each executive s compensation would have been as follows:

Name	**2008 Base Salary**	**2008 Performance-Based Cash Incentive Compensation**
Allan D. Keel	$ 370,000	$ 117,237
E. Joseph Grady	$ 340,000	$ 107,732
Tracy Price	$ 200,000	$ 51,825
Jay S. Mengle	$ 220,000	$ 55,935
Tommy H. Atkins	$ 200,000	$ 51,730

As a result of anticipated low commodity prices for 2009 and the corresponding negative impact on revenues, a reduced capital expenditure budget, and the resulting impact on the ability to formulate meaningful performance goals for the plan for 2009, upon the recommendation of the Compensation Committee, the Board has suspended the performance-based cash incentive compensation plan for the executive officers and all other Company employees for the fiscal year ending December 31, 2009.

Discretionary Cash Incentive Compensation

As one way of accomplishing our executive compensation program objectives, the Compensation Committee has the ability to award discretionary cash bonuses to our executive officers for their contribution to our financial and operational success. These amounts are in addition to amounts awarded under our annual performance-based cash incentive compensation plan, and are typically awarded in cases where awards under our performance incentive plans are not commensurate with the performance and contribution of any individual executive.

In March 2008, Mr. Atkins was awarded a discretionary cash bonus of $40,000 in recognition of his success in developing an internal prospect generation capability, including a technical team, which was an individual effort that the Compensation Committee believed was not adequately rewarded under the annual cash incentive compensation plan described above. No other discretionary cash bonuses were awarded to any executive officer in, or for, year 2008 performance.

Table of Contents

Long-Term Equity-Based Incentive Compensation

We grant equity awards to give our executive officers a longer-term stake in the Company, act as a long-term retention tool and align employee and stockholder interests by increasing compensation as stockholder value increases. In addition, the Compensation Committee occasionally grants equity awards in recognition of outstanding service to the Company. To achieve these objectives, the Compensation Committee has generally relied on the issuance of restricted stock and stock options.

General

We believe that stock options reduce stockholder dilution, conserve shares available under our stock plans, align employees compensation goals with the creation of stockholder value and encourage our executive officers to take necessary and appropriate steps to increase our stock price. We believe that restricted stock encourages our executive officers to adopt a view towards long-term value while providing a retention incentive even in the event of a decline in the stock price. The Board believes that stock options and restricted stock awards are an effective incentive for executive officers, managers and other key employees to create value for us and our stockholders since the value of restricted stock and options bear a direct relationship to appreciation in our stock price. In addition, by using stock-based compensation, we can focus much needed cash flow, which would otherwise be paid out as compensation, back into the daily operations of our business.

No stock options were granted to our executive officers in fiscal 2006, 2007 or 2008. We chose to provide equity compensation in the form of restricted stock rather than stock options because restricted stock awards incentivize our executive officers to build long-term value for our stockholders and provide a greater retention incentive in the current economic environment and at this stage of the Company s development.

For fiscal 2008, as part of our compensation review process, we made several changes to our long-term equity-based incentive compensation. We made these changes to improve the retention incentives for our executive officers and to provide better incentives for the creation of long-term value for our stockholders.

In September 2008, we provided our five named executive officers and six other employees holding outstanding stock options with an exercise price of $17.00 per share (which were initially granted to our executives in connection with the recapitalization of the Company in 2005 and to the other employees as part of their initial compensation package) the option to exchange their substantially vested stock options for shares of unvested restricted stock at the rate of two stock options for one share of restricted stock. The ratio of options to shares of restricted stock was based on an estimated valuation of the exchanged options, which were substantially vested but out-of-the money, as compared to an estimated value for a number of equivalent unvested shares of restricted common stock, taking into account market prices and the proposed vesting schedule, among other factors. All of our executive officers agreed to exchange their $17.00 options for shares of restricted stock. The restricted stock granted pursuant to the exchange offer will vest as follows:

- 50% of the restricted shares received by each holder will vest over four years at a rate of 25% each year, or 100% upon a change of control or 100% upon the death or disability of an executive officer; and

- 50% of the restricted shares received by each holder will vest upon the earlier of the fifth anniversary of the grant date or a change of control or upon the death or disability of an executive officer.

LTIP

In addition, our Compensation Committee and Board also approved in 2008 a performance-based long-term equity incentive plan (the LTIP) designed to reward employees with equity based compensation on the basis of the Company attaining pre-determined performance measures, similar to our performance-based cash incentive compensation plan. All grants made under the LTIP are performance based, are calculated as a percentage of base salary earned during the plan year and are to be made in the form of restricted stock and stock option grants under the 2005 Stock Incentive Plan. All restricted stock awards and stock options granted pursuant to this plan will vest over four years at a rate of 25% each year.

In 2008 we amended our 2005 Stock Incentive Plan to increase the maximum aggregate number of shares of common stock which may be issued upon exercise of all awards under the 2005 Stock Incentive Plan by one million shares, and among other things, to accommodate LTIP awards, to make certain adjustments for the Company s reincorporation from Texas to Delaware, to make other changes to conform the 2005 Stock Incentive Plan s provisions to the final regulations under Section 409A of the Code and for certain other conforming and clarifying changes.

The pre-determined performance measures will be the same as the measures under the performance-based cash incentive compensation plan and consistent with our existing criteria for performance awards under our 2005 Stock Incentive Plan: (i) Production; (ii) EBITDAX; (iii) Reserve Replacement; (iv) F&DC; and (v) ROIC.

The Compensation Committee has established the minimum, target and maximum performance levels for each of these five performance categories and their appropriate weighting. The weighting assigned to each performance category is based on the importance of each category to our overall success, and are to be applied to each executive officer equally. The weighting for fiscal 2008 for each of the five categories was as follows:

Category	**Fiscal 2008**
Production	20%
EBITDAX	20%
Reserve Replacement	20%
F&DC	20%
ROIC	20%

Should our financial and operating results meet or exceed either the pre-determined minimum, target and maximum values assigned a particular performance category with linear interpolations between each level, then each executive officer is granted a dollar value of restricted stock awards and stock options based on a percentage of his or her annual salary.

The Compensation Committee established the minimum, target and maximum performance levels for fiscal 2008 as follows:

The minimum level is equal to 80% of the target level and is the level at which payout under the plan begins for the applicable performance measure. If the actual performance level for a measure is below the minimum level, no payout occurs with respect to that measure.

The target level is that at which 100% of the expected payout for the applicable performance measure will occur.

The maximum level is that at which 150% of the expected payout for the applicable performance measure will occur.

After giving consideration to past company performance and peer performance, we have set these performance levels so that the attainment of the targets is not assured and requires significant effort by our executives.

The actual percentage of annual salary paid to an executive officer as a bonus is dependent upon the extent to which we meet or exceed our pre-determined performance goals. Payment of annual equity incentive bonuses to our executive officers is not guaranteed and will be based upon our actual performance during the fiscal year, including meeting at least the minimum performance targets. The Compensation Committee does not have the discretion to modify the minimum, target and maximum levels for a fiscal year.

All grants will consist of 50% restricted stock awards and 50% stock option awards. The restricted stock awards will be based on our stock price at the time of the grant, and the dollar value of the stock options will be calculated using the Black-Scholes option pricing model.

For fiscal 2008, the Compensation Committee established the target bonus percentage for each executive officer after taking into account the position held by that officer and the importance of that officer to achieving our performance goals during the year, as well as published compensation surveys. The actual percentage of annual salary to be paid as the annual equity incentive bonus in 2008 ranged from 75% to 450% of the annual salary of Mr. Keel, 75% to 350% of the annual salary of Mr. Grady and from 50% to 300% of the annual salaries for Messrs. Price, Mengle and Atkins.

Mr. Keel s annual equity incentive bonus potential is higher than that of other currently employed executives primarily because of the compensation levels of comparable executives of peer group companies against whom his compensation is targeted and his greater influence over and responsibility for the entire Company. In addition, Mr. Keel s compensation reflects his leadership in developing strategic alternatives for the Company to enhance stockholder value.

Mr. Grady s annual equity incentive bonus potential is higher than that of other named executive officers, except for that of Mr. Keel, primarily because of his seniority, experience and stature in the industry, his reporting relationship to the Chief Executive Officer, the compensation levels of comparable executives of peer group companies against whom his compensation is targeted and his greater influence over and responsibility for the entire Company.

Mr. Price s, Mr. Mengle s and Mr. Atkins annual equity incentive bonus potential levels reflect their roles and responsibilities as officers of the Company and their individual contributions to the Company and the officer team.

For fiscal 2008, equity grants under the plan were approved during the first quarter of 2009, at the recommendation of the Compensation Committee and approval of the Board. See Narrative Disclosure to Summary Compensation Tables and Grants of Plan-Based Awards Table Stock Awards. For fiscal 2009, equity grants under the plan were suspended at the recommendation of the Compensation Committee as a result of anticipated low commodity prices for 2009 and the corresponding negative impact on revenues and a reduced capital expenditure budget.

Overriding Royalty Interest Plan Compensation

We provide compensation to our executive officers through our Overriding Royalty Interest Plan (the ORRI Plan), which is designed to reward the efforts of employees who are successful in exploring for oil and natural gas on our behalf. The program is available only to those employees that are directly involved in oil and natural gas exploration efforts, including Mr. Atkins, our Senior Vice President Exploration, who is the only named executive officer entitled to benefits under this plan. In order to be able to participate in the plan, a potential candidate must be recommended for participation by our president and approved by the Compensation Committee. Under the ORRI Plan, the participants share a portion of the gross revenue interest attributable to the original working interest held by us in certain of the oil and natural gas producing properties generated by the exploration program. In 2008, the Board approved several amendments to the ORRI Plan which included the following: (i) leasehold acreage in which the Company held less than a 73% net revenue interest would not be included in the program and no overriding royalty interest revenue distributions would be made from such properties; (ii) leasehold acreage acquired for the pursuit of unconventional, resource type plays would be considered an acquisition of probable reserves rather than an Exploratory Prospect under the ORRI Plan and therefore, except as provided for in (iii), not subject to the overriding royalty interest distribution provided for in the ORRI Plan, and (iii) the Company could award up to a 1% overriding royalty interest in an unconventional resource play to the Senior Vice

Table of Contents

President Exploration and any other participants it deems appropriate up to a maximum of 0.0125% per participant.

During fiscal 2008, the amount of $43,045 was paid to Mr. Atkins pursuant to the ORRI Plan.

Severance Benefits

Each of the employment agreements to which most of our executive officers are subject provide for severance and change of control payments upon a termination or change of control. Payments that are payable upon a termination or change of control are included in the respective employment agreement between the executive officer and the Company. The Company believes that the executive officers should be provided an incentive to consummate a change of control that would generate attractive returns for our stockholders. Without such an incentive, the executive officers may not diligently pursue such opportunities. In addition, severance provisions were included as a means of attracting and retaining executives and to provide replacement income if their employment is terminated because of a termination, except in certain circumstances. Each employment agreement contains similar but not identical provisions regarding payments upon termination or change of control and relevant provisions of those agreements are provided in the section titled Potential Payments upon Termination or Change of Control.

Other Benefits

In addition to base salaries, incentive compensation, equity awards, overriding royalty interest plan compensation and severance benefits, we provide other forms of compensation that are periodically reviewed by the Compensation Committee. Except as otherwise indicated, these benefits are available to all employees, including our named executive officers, and are offered for the purpose of providing competitive compensation and benefits to attract new employees and secure the continued employment of current employees.

401(k) Plan. We have a defined contribution 401(k) Plan that is designed to assist our executive officers and employees in providing for their retirement. Effective June 1, 2008, upon the recommendation of the Compensation Committee, the Board approved an amendment to the Company s 401(k) Plan to provide for 100% matching of each participant s deferral contributions up to 6% of the participant s compensation. In order to maintain the safe-harbor non-discrimination provisions of the 401(k) Plan, in lieu of 100% matching during the second half of 2008 the Company made a one-time discretionary contribution to the 401(k) Plan for each participant during December 2008. Effective January 1, 2009, the Company began matching 100% of each participant s deferral contributions up to 6% of the participant s compensation.

Health and Welfare Benefits. As with all of our employees generally, our executive officers are eligible to participate in medical, dental, vision, life insurance and accidental death and disability to meet their health and welfare needs. These benefits are provided so as to assure that we are able to maintain a competitive position in terms of attracting and retaining officers and other employees. This is a fixed component of compensation and the benefits are provided on a non-discriminatory basis to all of our employees.

Perquisites and Other Personal Benefits. We believe that the total mix of compensation and benefits provided to our executive officers is competitive and perquisites should generally not play a large role in our executive officers total compensation. As a result, the perquisites and other personal benefits we provide to our executive officers are limited and typically do not exceed $10,000 per person in any fiscal year.

Table of Contents

Other Matters

Tax and Accounting Treatment of Executive Compensation Decisions

We consider the anticipated tax treatment of our executive compensation program when setting levels and types of compensation. Section 162(m) of the Code generally disallows a tax deduction to public companies for compensation in excess of $1.0 million per person paid in any year to a company s chief executive officer or any of its three other most highly compensated executive officers (other than the chief financial officer and the chief executive officer), with certain performance-based compensation being specifically exempt from this deduction limit. During fiscal 2007 and 2008, none of our employees subject to this limit received Section 162(m) compensation in excess of $1.0 million. Consequently, the requirements of Section 162(m) did not affect the tax deductions available to us in connection with our senior executive compensation program for fiscal 2007 and 2008.

We account for stock-based awards based on their grant date fair value, as determined under GAAP. In connection with its approval of stock-based awards, the Compensation Committee is cognizant of and sensitive to the impact of such awards on stockholder dilution. The Compensation Committee also endeavors to avoid stock-based awards made subject to a market condition, which may result in an expense that must be marked to market on a quarterly basis. The accounting treatment for stock-based awards does not otherwise impact the Compensation Committee s compensation decisions.

Stock Ownership Guidelines and Hedging Prohibition

We do not currently have ownership requirements or a stock retention policy for our named executive officers. We do not have a policy that restricts our executive officers from limiting their economic exposure to our stock. We will continue to periodically review best practices and re-evaluate our position with respect to stock ownership guidelines and hedging prohibitions.

Summary Compensation

The following table sets forth the aggregate compensation awarded to, earned by or paid to our named executive officers for services rendered in all capacities during the fiscal years ended December 31, 2006, 2007 and 2008.

Summary Compensation Table for the Fiscal Years ended December 31, 2006, 2007 and 2008

ame and rincipal Position	Year	Salary ($)	Bonus[1] ($)	Stock Awards[2] ($)	Option Awards[3] ($)	Non-Equity Incentive Plan Compensation[4] ($)	All Other Compensation[5] ($)	Total ($)
llan D. Keel	2008	370,000		153,553	2,471,160		12,376	3,007,089
hief Executive	2007	240,000	100,000	73,282	2,153,250	105,600	9,600	2,681,732
fficer and President	2006	240,000		25,000	2,009,700	72,000	2,400	2,349,100
. Joseph Grady	2008	340,000		112,435	823,720		15,500	1,291,655
enior Vice President	2007	220,000	100,000	70,367	717,750	96,800	8,800	1,213,717
nd Chief Financial Officer	2006	220,000		22,919	669,900	66,000	29,641[6]	1,008,460
racy Price	2008	200,000		112,435	590,105		9,708	912,248
enior Vice President	2007	185,000	50,000	54,469	580,498	70,300	7,400	947,667

and/Business Development	2006	185,000	11,600	11,562	522,448	44,400	1,850	776,860
ay S. Mengle	2008	220,000		102,435	295,052		10,483	627,970
enior Vice President	2007	180,000	100,000	54,031	290,249	64,800	8,000	697,080
ngineering	2006	180,000	20,000	11,250	261,224	54,000	1,800	528,274
ommy H. Atkins	2008	200,000		100,636	251,122		52,129(7)	603,887
enior Vice President	2007	180,000	40,000	54,031	247,249	43,200	7,200	571,680
xploration	2006	180,000		11,250	222,524	75,600	1,800	491,174

(1) For a description of the amounts included in this column, see Compensation Discussion and Analysis Elements of Our Executive Compensation Program Discretionary Cash Incentive Compensation.

(2) Includes the dollar amount of compensation expense we recognized for the fiscal years ended December 31, 2008, 2007 and 2006 in accordance with GAAP. Pursuant to SEC rules and regulations, the amounts shown exclude the impact of estimated forfeitures related to service-based vesting conditions. These amounts reflect our accounting expense for these awards, and do not correspond to the actual value that will be recognized by our executive officers. Assumptions used in the calculation of these amounts are included in Note 6 to our audited financial statements included in our Annual Reports on Form 10-K for the fiscal years ended December 31, 2008, 2007 and 2006, as applicable. The awards for which compensation expense was recognized consist of awards granted on August 1, 2007 and March 1, 2006. See Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table below for a description of the material features of these awards.

(3) Includes the dollar amount of compensation expense we recognized for the fiscal years ended December 31, 2008, 2007 and 2006 in accordance with GAAP. Pursuant to SEC rules and regulations, the amounts shown exclude the impact of estimated forfeitures related to service-based vesting conditions. These amounts reflect our accounting expense for these awards, and do not correspond to the actual value that will be recognized by our executive officers. Assumptions used in the calculation of these amounts are included in Note 13 to our audited financial statements included in our Annual Reports on Form 10-K for the fiscal years ended December 31, 2008, 2007 and 2006, as applicable. The awards for which compensation expense was recognized consist of awards granted on February 28, 2005 for Messrs. Keel and Grady and April 1, 2005 for Messrs. Price, Mengle and Atkins. See Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table below for a description of the material features of these awards. No options were granted to our executive officers in fiscal 2008, 2007 or fiscal 2006.

(4) For a description of the amounts included in this column, see Compensation Discussion and Analysis Elements of Our Executive Compensation Program Performance-Based Cash Incentive Compensation.

(5) Except as otherwise noted, these amounts represent 401(k) plan matching contributions during fiscal 2008, 2007 and 2006.

(6) Pursuant to his employment contract, Mr. Grady was reimbursed a total of $27,441 for commuting costs incurred by him prior to his relocation to Houston, Texas in late 2006. Reimbursements were for temporary housing and air fare. In addition, we contributed $2,200 to Mr. Grady s 401(k) plan during fiscal 2006.

(7) Mr. Atkins was paid $43,045 pursuant to the Company s ORRI Plan during 2008. For a description of the amounts included in this column, see Compensation Discussion and Analysis Elements of Our Executive Compensation Program Overriding Royalty Interest Plan Compensation. Mr. Atkins also received a contribution from us of $9,084 to his 401(k) plan for the fiscal year.

Table of Contents

Grants of Plan-Based Awards for Fiscal Year 2008

The following table provides information concerning each grant of an award made to our named executive officers under any plan, including awards, if any, that have been transferred during the fiscal year ended December 31, 2008.

			Estimated Future Payouts Under Non-Equity Incentive Plan Awards[1]			All Other Stock Awards: Number of Shares of Stock or Units	Grant Date Fair Value of Stock and Option Awards
	Grant	Approval	Threshold	Target	Maximum		
Name	Date	Date	($)[2]	($)	($)	(#)[3]	($)
Allan D. Keel	9/8/08	8/15/08	185,000	314,500	444,000	270,000	2,470,500
E. Joseph Grady	9/8/08	8/15/08	170,000	289,000	408,000	90,000	823,500
Tracy Price	9/8/08	8/15/08	80,000	140,000	200,000	90,000	823,500
Jay S. Mengle	9/8/08	8/15/08	88,000	154,000	220,000	45,000	411,750
Thomas H. Atkins	9/8/08	8/15/08	80,000	140,000	200,000	38,350	350,903

(1) For the fiscal year ending December 31, 2008, the amounts included in the threshold, target and maximum columns represent, assuming the attainment of the appropriate targeted performance goals, 50%, 85% and 120%, respectively, of the annual base salaries for Messrs. Keel and Grady and 40%, 70% and 100%, respectively, of the annual base salaries for Messrs. Price, Mengle and Atkins.

(2) Under our performance-based cash incentive compensation plan, this category is referred to as the minimum payout level.

(3) The executive officers elected to exchange substantially vested stock options with an exercise price of $17.00 per share for unvested restricted stock at the rate of two stock options for one share of restricted stock.

Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table

The following is a discussion of material factors necessary to an understanding of the information disclosed in the Summary Compensation Table and the Grants of Plan-Based Awards Table.

Employment Agreements

The Company has entered into amended and restated employment agreements with its executive officers during 2008. The compensation provisions of the employment agreements were designed with input from Longnecker & Associates and ECI and contain a compensation package designed to motivate and retain the executive officers.

Between December 29 and 31, 2008, the Company entered into amended and restated employment agreements with each of its named executive officers.

The agreements were entered into to, among other things, modify provisions relating to the federal income tax treatment of certain arrangements in order to meet the December 31, 2008 deadline for compliance with Section 409A of the Code, reflect market-based changes in compensation approved in mid-2008 by the Compensation Committee and the Board and provide for new terms of the agreements, since the initial terms of the existing employment agreements expired. In addition, the amended and restated employment agreements were entered into to provide an incentive for consistent, longer-term performance and achievement of strategic objectives to compensate our named executives for the value of their contributions, provide total compensation that is flexible enough to respond to changing market conditions and that aligns compensation with performance and provides total compensation that will motivate and retain our executive officers, support an internal culture of Company loyalty and dedication to the Company s interests.

The agreements entered into with Messrs. Keel and Grady each provide for a term of three years and the agreements entered into with Messrs. Mengle, Atkins and Price each provide for a term of two years. Each agreement provides for automatic yearly extensions of the term, after the initial term, unless the Company or the officer elects not to extend the agreement.

Each agreement provides for a base salary (which is subject to increase at the discretion of the Company s Board or a committee thereof) and participation in the Company s Annual Cash Incentive Bonus Plan and LTIP. The initial base salaries of each executive are as follows: Mr. Keel, $370,000; Mr. Grady, $340,000; Mr. Mengle, $220,000; Mr. Atkins, $200,000; and Mr. Price, $200,000.