Bonanza Creek Energy, Inc.
Form S-1/A
November 25, 2011

Use these links to rapidly review the document

Table of Contents

As filed with the Securities and Exchange Commission on November 23, 2011

Registration No. 333-174765

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Amendment No. 4 to

Form S-1

REGISTRATION STATEMENT UNDER THE SECURITIES ACT OF 1933

Bonanza Creek Energy, Inc.

(Exact name of registrant as specified in its charter)

Delaware	**1311**	**61-1630631**
(State or other jurisdiction of incorporation or organization)	(Primary Standard Industrial Classification Code Number)	(I.R.S. Employer Identification No.)

410 17th Street, Suite 1500
Denver, Colorado 80202
(720) 440-6100
(Address, including zip code, and telephone number, including area code, of registrant's principal executive offices)

Michael R. Starzer
President and Chief Executive Officer
Bonanza Creek Energy, Inc.
410 17th Street, Suite 1500
Denver, Colorado 80202
(720) 440-6100
(Name, address, including zip code, and telephone number, including area code, of agent for service)

Copies to:

Dallas Parker
William S. Moss III
Mayer Brown LLP
700 Louisiana Street, Suite 3400
Houston, Texas 77002
(713) 238-3000

J. Michael Chambers
Keith Benson
Latham & Watkins LLP
717 Texas Avenue, 16th Floor
Houston, Texas 77002
(713) 546-5400

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

If any of the securities being registered on this Form are to be offered on a delayed or continuous basis pursuant to Rule 415 under the Securities Act of 1933 check the following box: 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 ý (Do not check if a smaller reporting company)	Smaller reporting company o

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

Table of Contents

PROSPECTUS (Subject to Completion)
Issued November 23, 2011

The information in this prospectus is not complete and may be changed. We and the selling stockholders may not sell these securities until the registration statement filed with the Securities and Exchange Commission is effective. This prospectus is not an offer to sell these securities, and we and the selling stockholders are not soliciting offers to buy these securities in any state where the offer or sale is not permitted.

Shares

Bonanza Creek Energy, Inc.

COMMON STOCK

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

Our common stock has been approved for listing on the New York Stock Exchange, subject to official notice of issuance, under the symbol "BCEI."

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

PRICE $ PER SHARE

	Price to Public	***Underwriting Discounts and Commissions***	***Proceeds to Bonanza Creek***	***Proceeds to Selling Stockholders***
Per Share	$	$	$	$
Total	$	$	$	$

The selling stockholders have granted the underwriters the right to purchase up to an additional shares to cover over-allotments.

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

The underwriters expect to deliver the shares of common stock to purchasers on , 2011.

MORGAN STANLEY *CREDIT SUISSE*

RAYMOND JAMES	*RBC CAPITAL MARKETS*	*BMO CAPITAL MARKETS*
HOWARD WEIL INCORPORATED	*KEYBANC CAPITAL MARKETS*	*STIFEL NICOLAUS WEISEL*
BNP PARIBAS		*SOCIETE GENERALE*

, 2011

Table of Contents

TABLE OF CONTENTS

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

Until , 2011 (the 25th day after the date of this prospectus), all dealers that buy, sell or trade our common stock, whether or not participating in this offering, may be required to deliver a prospectus. This requirement is in addition to the dealers' obligation to deliver a prospectus when acting as underwriters and with respect to their unsold allotments or subscriptions.

Industry and Market Data

The market data and certain other statistical information used throughout this prospectus are based on independent industry publications, government publications or other published independent sources. Some data is also based on our good faith estimates. Industry publications and other published independent sources generally state that they have obtained information from sources believed to be reliable but do not guarantee the accuracy and completeness of such information. Although we believe these third-party sources are reliable and that the information is accurate and complete, neither we nor the underwriters have independently verified the information. Likewise, we believe our internal research is reliable, but it has not been verified by any independent sources.

Table of Contents

PROSPECTUS SUMMARY

This summary provides a brief overview of information contained elsewhere in this prospectus. Because it is abbreviated, this summary does not contain all of the information that you should consider before investing in our common stock. You should read the entire prospectus carefully before making an investment decision, including the information presented under the headings "Risk Factors," "Cautionary Note Regarding Forward-Looking Statements" and "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the historical consolidated financial statements and unaudited pro forma financial information and related notes thereto included elsewhere in this prospectus. Unless otherwise indicated, information presented in this prospectus assumes that the underwriters' option to purchase additional common shares is not exercised. We have provided definitions for certain oil and natural gas terms used in this prospectus in the "Glossary of Certain Industry Terms" beginning on page 142 of this prospectus.

In this prospectus, unless the context otherwise requires, the terms "we," "us," "our" and the "company" refer to Bonanza Creek Energy, Inc. and its subsidiaries and Bonanza Creek Energy Company, LLC, its predecessor.

BONANZA CREEK ENERGY, INC.

Overview

Bonanza Creek Energy, Inc. is an independent oil and natural gas company engaged in the acquisition, exploration, development and production of onshore oil and associated liquids-rich natural gas in the United States. Our assets and operations are concentrated primarily in southern Arkansas (Mid-Continent region) and the Denver Julesburg ("DJ") and North Park Basins in Colorado (Rocky Mountain region). In addition, we own and operate oil producing assets in the San Joaquin Basin (California region). Our management team has extensive experience in acquiring and operating oil and gas properties, which we believe will contribute to the development of our sizable inventory of projects including those targeting the oily Cotton Valley sands in our Mid-Continent region and the Niobrara oil shale formation in our Rocky Mountain region. We operate approximately 99.4% and hold an average working interest of approximately 85.8% of our proved reserves, providing us with significant control over the rate of development of our long-lived, low-cost asset base.

Cawley, Gillespie & Associates, Inc., our independent reserve engineers, estimated our net proved reserves to be 32,860 MBoe as of December 31, 2010, 68.1% of which were classified as oil and natural gas liquids, and 35.1% of which were classified as proved developed. Our average net daily production rate during October 2011 was 4,813 Boe/d, which consisted of 72.5% oil and natural gas liquids.

	Estimated Proved Reserves at December 31, 2010(1)					Estimated Production for the Month Ended October 31, 2011			
	Total Proved (MBoe)	% of Total	% Proved Developed	% Oil and Liquids	PV-10 ($ in MM)(2)	Average Net Daily Production (Boe/d)	% of Total	Projected 2011 Capital Expenditures (millions)(3)	Net Proved Undeveloped Drilling Locations as of December 31, 2010
Mid-Continent	22,876	69.6%	26.2%	67.3%	$ 313.3	2,545	52.9%	$ 85.2	151.3
Rocky Mountain	9,098	27.7	57.2	67.1	135.3	2,085	43.3	74.9	77.3
California	886	2.7	38.3	98.8	13.0	183	3.8	2.0	13.6
Total	32,860	100.0%	35.1%	68.1%	$ 461.6	4,813	100%	$ 162.1	242.2

(1) Proved reserves were calculated using prices equal to the twelve month unweighted arithmetic average of the first-day-of-the-month price for each of the preceding twelve months, which were $79.43 per Bbl of crude oil and $4.38 per MMBtu of natural gas. Adjustments were made for location and the

1

Table of Contents

grade of the underlying resource, which resulted in an average decrease of $4.50 per Bbl of crude oil and an increase of $0.43 per MMBtu of natural gas.

(2) PV-10 is a non-GAAP financial measure and represents the present value of estimated future cash inflows from proved crude oil and natural gas reserves, less future development and production costs, discounted at 10% per annum to reflect timing of future cash inflows and using the twelve month unweighted arithmetic average of the first-day-of-the-month price for each of the preceding twelve months. PV-10 differs from Standardized Measure of Discounted Future Net Cash Flows ("Standardized Measure") because it does not include the effect of future income taxes. For a reconciliation of our Standardized Measure to PV-10, see "*Summary Reserve and Operations Data Non-GAAP Financial Measures and Reconciliation PV-10*."

(3) Projected capital expenditures for our Mid-Continent region include $17.7 million for the construction of the Dorcheat gas processing facility, which was completed in September 2011.

Development Projects by Region

Mid-Continent: In southern Arkansas, we are primarily targeting the oil-bearing Cotton Valley sands in the Dorcheat Macedonia and McKamie Patton fields. As of December 31, 2010, our estimated proved reserves in this region were 22,876 MBoe, 67.3% of which were oil and natural gas liquids and 26.2% of which were proved developed, and we had an identified drilling inventory of approximately 188 gross (151.3 net) PUD drilling locations on our acreage. In 2011 we expect to drill and complete 40 gross (34.9 net) wells in the Dorcheat Macedonia field at a cost of approximately $1.7 million per well, and 2 gross (2.0 net) wells in the McKamie Patton field at a cost of approximately $1.2 million per well. As of October 31, 2011 we have drilled 36 gross (31.5 net) wells in the Dorcheat Macedonia field. This activity brings our current operated well count to 138 gross (120.5 net) producing wells.

We also own and operate the McKamie and Dorcheat gas processing facilities and approximately 150 miles of associated gathering pipelines that serve our acreage position in southern Arkansas. These facilities have a combined maximum processing capacity of 27.5 MMcf/d of natural gas and 30,000 gallons per day of natural gas liquids. These two facilities currently process all of the natural gas that we produce from the Dorcheat Macedonia and McKamie Patton fields.

Rocky Mountain: In the DJ and North Park Basins in Colorado, we hold 83,617 gross (62,688 net) acres that currently produce oil, natural gas and CO_2 from the Pierre B, Niobrara, Codell, J-Sand, D-Sand and Dakota formations. As of December 31, 2010, our estimated proved reserves in this region were 9,098 MBoe, of which 67.1% were oil and 57.2% were proved developed. In the DJ Basin we control 29,262 net acres and, as of December 31, 2010, have identified approximately 93 gross (73.3 net) vertical PUD drilling locations targeting the Codell sand and Niobrara oil shale formations. In 2011, we expect to drill and complete 63 gross (62.8 net) vertical wells targeting the Codell sand and Niobrara oil shale formations, at a cost of approximately $0.8 million per well. As of October 31, 2011, we have completed 59 gross (59.0 net) of our planned 2011 wells. In addition, we believe that horizontal drilling and multi-stage fracture completion techniques are an attractive alternative to vertical well completions for the Niobrara oil shale. To date, we have drilled all four, and completed three, of our operated horizontal Niobrara wells in the DJ Basin planned for 2011. In the North Park Basin we control 33,426 net acres and, as of December 31, 2010, have identified four gross (4.0 net) vertical PUD locations. We have identified highly fractured and dual porosity areas which we believe will support vertical and horizontal drilling techniques for the Niobrara. The development and testing of the North Park Basin began this year with the drilling of 2 gross (2.0 net) vertical wells at a drilling and evaluation cost of approximately $2.9 million for the first well and an estimated $2.2 million for the second well.

California: In California, we employ thermal techniques to recover heavy oil in the Kern River and Midway Sunset fields, and we produce medium gravity oil from the Greeley and Sargent fields. As of December 31, 2010, our estimated proved reserves in this region were 886 MBoe, of which 98.8% were oil

Table of Contents

and 38.3% were proved developed. We have identified approximately 18 gross (13.6 net) PUD drilling opportunities in these fields. In 2011, we expect to drill 3 gross (1.5 net) wells with individual well costs ranging from approximately $0.3 to $1.0 million. As of October 31, 2011, we have drilled and completed 3 gross (1.5 net) wells.

Recent Developments

On July 24, 2011, we completed our first operated horizontal Niobrara well, the State Antelope 11-2Hz, and reported a 24-hour rate after cleanup on August 1, 2011 of 738 Boe/d and a 30-day rate of 362 Boe/d. Our second operated horizontal Niobrara well, the North Platte 44-11-28Hz, was completed on August 9, 2011 and reported a 24-hour rate after cleanup on August 19, 2011 of 887 Boe/d and a 30-day rate of 599 Boe/d. These two wells cost an average of $3.9 million per well. We recently completed our third operated horizontal Niobrara well, the State Antelope 11-14-1Hz, reporting a 24-hour rate after cleanup on November 1, 2011 of 886 Boe/d. Our fourth and final operated horizontal Niobrara well of 2011, the State Whitetail 14-11-36Hz, has been drilled and is currently being fracture stimulated. We expect costs for these two wells to average $4.3 million per well.

Our Business Strategies

Our goal is to increase stockholder value by investing capital to increase our production, cash flow and proved reserves. We intend to accomplish this goal by focusing on the following key strategies:

Increase Production from Existing Low-Cost Proved Inventory. In the near term, we intend to accelerate the drilling of our lower-risk vertical PUD drilling locations in southern Arkansas and in the oily Codell and Niobrara formations of the DJ Basin. Substantially all of these infill locations are characterized by multiple productive horizons.

Test and Evaluate Our Niobrara Oil Shale Acreage. We hold approximately 83,617 gross (62,688 net) acres prospective for the development of the Niobrara oil shale in Weld and Jackson Counties, Colorado, and own approximately 17,400 acres of proprietary 3-D seismic data covering our acreage position in Weld County, which aids in identifying our horizontal drilling locations. Although full-scale vertical drilling of the Niobrara oil shale commenced in the early 1990s, we and other operators in the region, including EOG Resources (DJ Basin and North Park Basin), Noble Energy (DJ Basin), and PDC Energy (DJ Basin) have recently applied horizontal drilling and multi-stage fracture stimulation techniques to enhance recoveries and economic returns.

Exploit Additional Development Opportunities. We are evaluating additional resource potential opportunities that could result in future development projects on several of our assets. For example, we have evaluated and believe we may achieve attractive returns by exploiting the Lower Smackover (Brown Dense) trend in our southern Arkansas acreage. We have 5,672 net acres prospective for the Brown Dense. Finally, we believe there are additional thermal recovery opportunities in California.

Pursue Accretive Acquisitions. We intend to pursue bolt-on acquisitions in regions where we operate and where we believe we possess a strategic or technical advantage, such as southern Arkansas where we own a gas processing facility and the associated infrastructure. In addition, we intend to focus on other oil and liquids-rich opportunities where we believe our operational experience will enhance the value and performance of acquired properties.

Maintain High Degree of Operatorship. We currently have and intend to maintain a high working interest in our assets, thereby allowing us to leverage our technical, operating and management skills and control the timing of our capital expenditures.

Table of Contents

Our Competitive Strengths

We believe the following combination of strengths will enable us to implement our strategies:

Significant Drilling Inventory. We have identified 303 gross (242.2 net) PUD drilling locations, providing us with multiple years of drilling inventory.

Niobrara Resource Potential. Since 2005, we have accumulated 62,688 net acres in Weld and Jackson Counties, Colorado, targeting the Niobrara formation. Our acreage is proximate to horizontal drilling operations which have been successfully completed by other operators. Significant increases in permitting, spud notices and reported oil and gas production involving the Niobrara formation in these counties have made this area one of the most active oil shale plays in the United States. In Weld County, the average initial 30-day production rate is 318 Boe/d from 70 wells with oil and gas production and no dry holes reported to the state regulatory commission. In the North Park Basin, EOG Resources has completed seven wells horizontally in an area of the Niobrara that we believe to be geologically similar to our acreage position based on electric and porosity log response. The average initial 30-day production rate from these wells has been 294 Boe/d.

We believe our significant acreage position in the Niobrara represents production, reserve and value growth potential and that the continued development of this play by other operators validates our investment in this play and will result in the continued development of infrastructure in the area. Geological risks associated with our Weld County acreage position have been mitigated by the high volume of data provided through the drilling, completion and production of thousands of vertical wells in the Niobrara in close proximity to and within our acreage. We own proprietary 3-D seismic surveys on 17,400 acres of our properties in Weld County and 22 proprietary 2-D seismic lines in Jackson County. Additionally, adequate gathering systems are in place in this region, enabling a short time period from well completion to first product sales.

High Degree of Operational Control. We hold an average working interest in our properties of approximately 85.8% and operate approximately 99.4% of our estimated proved reserves, which allows us to employ the drilling and completion techniques we believe to be most effective, manage costs and control the timing and allocation of our capital expenditures.

Gas Processing Capability in Southern Arkansas. The processing of our natural gas at our McKamie facility improves our well development economics in southern Arkansas. In addition, we expanded our infrastructure by adding an additional gas processing facility in our Dorcheat Macedonia field to accommodate future drilling on our acreage in this region.

Experienced Management. Our senior management team averages more than 28 years of industry experience, and certain members of our executive management have worked together for over 24 years. Our management team has significant acquisition experience, having negotiated and closed more than 12 acquisition transactions since 2006.

Financial Flexibility. Our capital structure is intended to provide a high degree of financial flexibility to grow our asset base, both through organic projects and opportunistic acquisitions. Immediately following the completion of this offering, we expect to have no indebtedness and $ million of liquidity, comprised of $220 million of availability under our credit facility and approximately $ million of cash on hand.

Table of Contents

Corporate Restructuring

On December 23, 2010, our predecessor, Bonanza Creek Energy Company, LLC ("BCEC") was recapitalized through the following series of transactions (collectively referred to as our "Corporate Restructuring"):

- we issued shares of our common stock to Project Black Bear LP ("Black Bear"), an entity advised by West Face Capital Inc. ("West Face Capital"), and to certain clients of Alberta Investment Management Corporation ("AIMCo") in exchange for $265 million in cash;

- BCEC contributed to us all of its ownership interest in Bonanza Creek Energy Operating Company, LLC ("BCEOC") in exchange for shares of our common stock;

- members of Holmes Eastern Company, LLC ("HEC") contributed all of their outstanding membership interests in HEC to us in exchange for cash and shares of our common stock; and

- we repaid certain of BCEC's indebtedness and assumed the remaining balance outstanding under BCEC's credit facility.

Following completion of these transactions, BCEC was dissolved and the shares of our common stock held by BCEC were distributed for the benefit of its members.

Credit Facility

On March 29, 2011, we entered into a four-year $300 million credit agreement with a syndicate of banks providing for a senior secured revolving credit facility with an initial borrowing base of $130 million and with a $5 million subfacility for standby letters of credit. On September 15, 2011, the borrowing base was increased to $180 million with a $15 million subfacility for standby letters of credit. On November 23, 2011, the lenders agreed to increase the borrowing base to $220 million, effective upon execution of the final agreements. For a description of the material terms of our credit facility, see "*Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Credit facility.*"

Class B Common Stock Conversion

Immediately prior to the consummation of this offering, 10,000 shares of our Class B common stock, par value $0.001 per share ("Class B Common Stock"), issued in the form of shares of restricted stock to certain of our employees pursuant to our Management Incentive Plan, will automatically be converted into a number of shares of our Class A Common Stock pursuant to a formula set forth in our amended and restated certificate of incorporation. Such shares of our Class A Common Stock subsequently will be reclassified as shares of our common stock pursuant to our second amended and restated certificate of incorporation. See "*Certain Relationships and Related Party Transactions Class B Common Stock Conversion*." We expect to issue shares of our common stock upon conversion of the Class B Common Stock and reclassification of our Class A Common Stock based on an assumed initial public offering price of $ per share (the midpoint of the price range set forth on the cover page of this prospectus).

Risk Factors

Investing in our common stock involves risks that include the speculative nature of oil and natural gas exploration, competition, volatile oil and natural gas prices and other material factors. In particular, the following considerations may offset our competitive strengths or have a negative effect on our ability to

Table of Contents

execute our business strategies as well as on activities on our properties, which could cause a decrease in the price of our common stock and result in a loss of all or a portion of your investment:

- Our future revenues are dependent on our ability to successfully replace our proved producing reserves.
- A decline in oil and natural gas prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments.
- Our identified drilling locations are scheduled over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.
- Unless we replace our oil and gas reserves, our reserves and production will decline.
- Our estimated reserves are based on many assumptions that may turn out to be inaccurate. Any significant inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.
- The present value of future net revenues from our proved reserves will not necessarily be the same as the current market value of our estimated oil and natural gas reserves.
- We have incurred losses from operations during certain periods since our inception and may continue to do so in the future.
- We expect to be a "controlled company" within the meaning of NYSE rules and, as a result, would qualify for and may rely on exemptions from certain corporate governance requirements.

For a discussion of these risks and other considerations that could negatively affect us, including risks related to this offering and our common stock, see "*Risk Factors*" beginning on page 16 and "*Cautionary Note Regarding Forward-Looking Statements*."

Principal Stockholders

Our principal stockholder, Black Bear, is an affiliate of West Face Capital, a Toronto-based investment management firm with over $2.0 billion of assets under management. West Face Capital specializes in event-oriented investments where its ability to navigate complex investment processes is the most significant determinant of returns and invests across the capital structure with specializations in natural resource industries, distressed debt, high yield debt and common equity. West Face Capital indirectly holds its interest in our common stock through Black Bear, a Delaware limited partnership formed by West Face Capital as a special purpose vehicle to invest in our securities on behalf of its limited partner investors. Pursuant to an advisory agreement, West Face Capital has authority to direct the trading and investing activities of Black Bear, including the power to vote and control the disposition of the shares of our Class A Common Stock held by Black Bear (approximately 46.63% of our issued and outstanding shares prior to this offering). West Face Capital and AIMCo, on behalf of certain of its clients, have entered into an investment management agreement pursuant to which West Face Capital has the right to vote the shares of our common stock held by certain clients of AIMCo. West Face Capital, via the investment management agreement with AIMCo and an advisory agreement with Black Bear, has the power to vote 72.66% of our issued and outstanding common stock prior to this offering and, therefore, prior to this offering may control the outcome of any matter submitted to a vote of the stockholders, including the election of our board of directors.

Corporate Information

Our principal executive offices are located at 410 17th Street, Suite 1500, Denver, Colorado 80202, and our telephone number at that address is (720) 440-6100. Our website is www.bonanzacrk.com. Information on our website or any other website is not incorporated by reference herein and does not constitute a part of this prospectus.

Table of Contents

THE OFFERING

Common stock offered by us.	shares
Common stock offered by selling stockholders	shares
Common stock to be outstanding after this offering	shares
Common stock owned by the selling stockholders after this offering	shares
Over-allotment option	shares
Use of proceeds	We estimate that our net proceeds from the sale of common stock in this offering will be approximately $ million, assuming an initial public offering price of $ per share (the midpoint of the price range set forth on the cover page of this prospectus) and after deducting estimated expenses and underwriting discounts and commissions of approximately $ million. Each $1.00 increase (decrease) in the public offering price will increase (decrease) our expected net proceeds by approximately $ million. We intend to use a portion of the net proceeds from this offering to (i) repay all outstanding indebtedness under our credit facility, which as of July 31, 2011, was approximately $99.9 million; (ii) fund our drilling and development program; and (iii) fund the expansion of our gas processing facilities. We will not receive any proceeds from the sale of shares by the selling stockholders. Affiliates of certain of the underwriters are lenders and agents under our credit facility and, accordingly, will receive a portion of the net proceeds from this offering through the repayment of outstanding borrowings under the credit facility. See "*Underwriters; Conflicts of Interest*."
Dividend policy	We do not intend to pay any cash dividends on our common stock. We intend to retain any earnings for use in the operation of our business and to fund future growth. In addition, our credit facility prohibits us from paying cash dividends. See "*Dividend Policy*."
New York Stock Exchange listing	Our common stock has been approved for listing on the NYSE, subject to official notice of issuance, under the symbol "BCEI."
Risk factors	You should carefully read and consider the information beginning on page 16 of this prospectus set forth under the heading "*Risk Factors*" and all other information set forth in this prospectus before deciding to invest in our common stock.

Unless specifically stated otherwise, all information in this prospectus:

- gives effect to the conversion of all shares of Class B Common Stock into shares of Class A Common Stock and the subsequent reclassification of our Class A Common Stock immediately prior to this offering, assuming pricing of this offering at the midpoint of the price range set forth on the cover page of this prospectus; and

- assumes no exercise of the over-allotment option.

Table of Contents

SUMMARY HISTORICAL AND PRO FORMA CONSOLIDATED FINANCIAL DATA

The following tables set forth summary historical and pro forma financial data of us and our predecessor, BCEC and pro forma financial data to give effect to the acquisition of HEC as of and for the periods indicated. The consolidated statement of operations data for the years ended December 31, 2008 and 2009 and the period ended December 23, 2010 are derived from the audited consolidated financial statements of BCEC included elsewhere in this prospectus. The consolidated balance sheet data as of December 31, 2010 is derived from our audited consolidated financial statements included elsewhere in this prospectus. The consolidated balance sheet data as of December 31, 2009 is derived from the audited consolidated financial statements of BCEC included elsewhere in this prospectus. The consolidated balance sheet data as of December 31, 2008 is derived from the audited consolidated financial statements of BCEC which are not included in this prospectus. The consolidated statement of operations data for the nine months ended September 30, 2010 are derived from the unaudited financial statements of BCEC appearing elsewhere in this prospectus, and the consolidated statement of operations data for the period from inception (December 23, 2010) to December 31, 2010 and the nine months ended September 30, 2011 and the consolidated balance sheet data as of September 30, 2011 are derived from our financial statements appearing elsewhere in this prospectus. In management's opinion, these financial statements include all adjustments necessary for the fair presentation of our financial condition as of such dates and our results of operations for such periods.

The summary unaudited pro forma statement of operations of Bonanza Creek Energy, Inc. for the year ended December 31, 2010 gives effect to our Corporate Restructuring as if it had occurred on January 1, 2010. The summary unaudited balance sheet of Bonanza Creek Energy, Inc. as of September 30, 2011 gives effect to this offering and the repayment of indebtedness as if they had occurred on September 30, 2011.

The summary historical and pro forma consolidated financial data should be read in conjunction with "*Selected Historical Consolidated and Unaudited Pro Forma Financial Data*" and "*Management's Discussion and Analysis of Financial Condition and Results of Operations*" and both our and our predecessor's financial statements and the notes to those financial statements included elsewhere in this document. The financial information included in this prospectus may not be indicative of our future results of operations, financial position and cash flows.

Table of Contents

	Bonanza Creek Energy Company, LLC (Predecessor)				Bonanza Creek Energy, Inc.		Bonanza Creek Energy, Inc. Pro Forma[(2)]
	Year Ended December 31, 2008	Year Ended December 31, 2009	Period Ended December 23, 2010[(1)]	Nine Months Ended September 30, 2010	Period from Inception (December 23, 2010) to December 31, 2010	Nine Months Ended September 30, 2011	Year Ended December 31, 2010
				(unaudited)		(unaudited)	(unaudited)
	(in thousands, except per share data)						
Statement of Operations Data:							
Revenues:							
Oil sales	$ 39,967	$ 27,601	$ 34,431	$ 24,412	$ 1,325	$ 57,177	$ 45,413
Natural gas sales	5,165	3,671	6,226	4,807	207	9,283	10,253
Natural gas liquids and CO_2 sales	2,782	3,169	7,672	5,469	213	9,076	8,365
Total revenues	$ 47,914	$ 34,441	$ 48,329	$ 34,688	$ 1,745	$ 75,536	$ 64,031
Operating expenses:							
Lease operating	20,434	13,449	14,792	10,581	483	14,461	17,285
Severance and ad valorem taxes	1,847	2,148	1,621	1,055	70	3,860	2,524
Depreciation, depletion and amortization	25,463	14,108	14,225	11,554	506	21,083	20,917
General and administrative	7,477	7,610	8,375	6,289	323	9,116	9,338
Employee stock compensation[(3)]							
Exploration	25	131	361	202		573	380
Impairment of oil and gas properties[(4)]	26,437	579				4,067	
Cancelled private placement[(5)]			2,378	2,378			2,378
Total operating expenses	$ 81,683	$ 38,025	$ 41,752	$ 32,059	$ 1,382	$ 53,160	$ 52,822
Income (loss) from operations	(33,769)	(3,584)	6,577	2,629	363	22,376	11,209
Other income (expense):							
Interest expense	(12,870)	(16,582)	(18,001)	(13,494)	(58)	(2,687)	(1,263)
Amortization of debt discount	(5,987)	(7,963)	(8,862)	(6,556)			
Write off of deferred financing costs			(1,663)	(1,663)			(1,663)
Gain on sale of oil and gas properties	8	303	4,055	4,055			4,055
Unrealized gain (loss) in fair value of warrant put option[(6)]	70,972	(80,640)	34,345	23,672			
Unrealized gain (loss) in fair value of commodity derivatives	48,716	(34,589)	(7,605)	(2,523)	(514)	7,096	(8,119)
Realized gain (loss) on settled commodity derivatives	1,913	13,451	5,919	4,897	(47)	(2,353)	5,872
Other income (loss)	(229)	(179)	19	125		(100)	(47)

Total other income (expense)	102,523	(126,199)	8,207	8,513	(619)	1,956	(1,165)
Income (loss) before income taxes	68,754	(129,783)	14,784	11,142	(256)	24,332	10,044
Income tax benefit (expense)(7)					94	(11,464)	(3,696)
Net income (loss)	$ 68,754	$ (129,783)	$ 14,784	$ 11,142	$ (162)	$ 12,868	$ 6,348
Net income per common share(8)							
Basic					$ (0.01)	$ 0.44	
Diluted					$ (0.01)	$ 0.44	
Weighted average shares outstanding							
Basic					29,123	29,123	
Diluted					29,123	29,123	

(1) We completed our Corporate Restructuring on December 23, 2010. The operating results of BCEC for the period ended December 23, 2010 are included in the statement of operations presented above.

(2) The pro forma information above gives effect to our Corporate Restructuring as if it had occurred on January 1, 2010.

(3) We will recognize employee stock-based compensation expense immediately prior to the consummation of this offering. We also expect to have stock-based compensation expense for future awards. See "*Management's Discussion and Analysis of Financial Condition and Results of Operations Selected Factors and Trends Affecting Our Results of Operations Stock-based Employee Compensation Expenses.*"

(4) The impairment for the year ended 2008 resulted from a write-down of the carrying value of our oil and natural gas reserves due to depressed year-end oil and natural gas prices.

Table of Contents

(5) Expenditures in connection with a cancelled private placement of our preferred stock.

(6) In connection with its purchase of our senior subordinated notes, D. E. Shaw Synoptic Portfolios 5, L.L.C. received warrants to purchase equity interests in our predecessor. These warrants contained a put right exercisable beginning on May 17, 2014. The periods presented for our predecessor reflect the changes in the fair market value of that put option. The warrants and aggregate warrant exercise price were exchanged for shares of our common stock in connection with our Corporate Restructuring.

(7) Our predecessor, BCEC, was a partnership for federal income tax purposes and, therefore, was not subject to entity-level taxation. Our pro forma results reflect our taxation as a corporation at an estimated combined state and federal income tax rate of 36.8%.

(8) As a limited liability company, ownership interests in our predecessor were held as units rather than shares.

	Bonanza Creek Energy Company, LLC (Predecessor)		**Bonanza Creek Energy, Inc.**		
	As of December 31,				**As of September 30, 2011 As Adjusted[1]**
	2008	**2009**	**As of December 31, 2010**	**As of September 30, 2011**	
				(unaudited)	**(unaudited)**
			(in thousands)		
Balance Sheet Data:					
Cash and cash equivalents	$ 4,088	$ 2,522	$	$ 153	
Property and equipment, net	195,280	188,367	496,582	596,454	
Total assets	241,625	211,552	516,104	626,903	
Long term debt, including current portion:					
Credit facility	107,000	99,000	55,400	132,100	
Senior subordinated notes, net of discount	75,499	92,442			
Second lien term loan[2]					
Subordinated unsecured note	10,000	10,799			
Warrant put options[3]	828	81,468			
Total members'/stockholders' equity (deficit)	35,988	(93,795)	356,380	369,318	

Table of Contents

	Bonanza Creek Energy Company, LLC (Predecessor)				Bonanza Creek Energy, Inc.	
	Year Ended December 31,					
	2008	2009	Period Ended December 23, 2010[4]	Nine Months Ended September 30, 2010	Period from Inception (December 23, 2010) to December 31, 2010	Nine Months Ended September 30, 2011
				(unaudited)		(unaudited)
	(in thousands)					
Other Financial Data:						
Net cash provided by operating activities	$ 11,128	$ 11,134	$ 22,759	$ 14,141	$ (1,633)	$ 37,333
Net cash provided by (used in) investing activities	(79,581)	(7,185)	(32,127)	(17,265)	(817)	(110,852)
Net cash provided by (used in) financing activities	72,541	(5,515)	9,297	(2,857)		73,671
Adjusted EBITDAX[5]	14,435	19,067	25,071	18,414	822	45,646

(1) As adjusted for this offering and the application of proceeds as described in "*Use of Proceeds*."

(2) Our $30 million second lien term loan was fully funded on May 7, 2010 and repaid in full in connection with our Corporate Restructuring on December 23, 2010.

(3) Warrants and the aggregate warrant exercise price were exchanged for our common shares in connection with our Corporate Restructuring on December 23, 2010.

(4) We completed our Corporate Restructuring on December 23, 2010. The cash flows from BCEC's operations for the audited period from January 1, 2010 to December 23, 2010 are included in the results presented above.

(5) Adjusted EBITDAX is an unaudited non-GAAP financial measure. For a definition of Adjusted EBITDAX and a reconciliation of Adjusted EBITDAX to our net income (loss) and to net cash provided by (used in) operating activities, see "*Summary Reserve and Operations Data Non-GAAP Financial Measures and Reconciliation Adjusted EBITDAX*," below.

Table of Contents

SUMMARY RESERVE AND OPERATIONS DATA

The following tables present summary information regarding the estimated net proved oil and natural gas reserves and the historical operating data of us, our predecessor BCEC, and HEC, as of the dates indicated. The estimates of our net proved reserves at December 31, 2010 and of BCEC at December 31, 2009 are based on the December 31, 2010 and 2009 reserve reports prepared by Cawley, Gillespie & Associates, Inc., our independent reserve engineers. The December 31, 2008 estimates of net proved reserves of BCEC are based on a reserve report prepared by MHA Petroleum Consultants LLC, independent reserve engineers.

For additional information regarding our reserves, please see "*Business Development Projects by Region*" and Note 14 to our audited consolidated financial statements included elsewhere in this prospectus.

	Bonanza Creek Energy Company, LLC (Predecessor)		Bonanza Creek Energy, Inc.
	As of December 31,		
	2008	2009[1]	2010[2]
Estimated Proved Reserves:			
Crude oil (MBbls)	11,294	12,913	18,601
Natural gas (MMcf)	19,906	27,610	62,884
Natural gas liquids (MBbls)	1,162	2,357	3,778
Total proved (MBoe)[3]	15,774	19,872	32,860
Proved developed producing (MBoe)	4,550	4,540	7,478
Proved developed non-producing (MBoe)	1,549	1,340	4,048
Total proved developed (MBoe)	6,099	5,880	11,526
Proved undeveloped (MBoe)	9,675	13,992	21,335
PV-10 ($ in millions)[4]	$ 84.7	$ 208.2	$ 461.6

(1) The 2009 reserve report excludes proved reserves attributable to our ownership in the Jasmin property in California, which we sold on March 31, 2010. At December 31, 2009, the Jasmin property had proved developed and total proved reserves of 401 MBoe and 568 MBoe, respectively, and a PV-10 value of $7.9 million.

(2) The 2010 reserve report includes proved reserves attributable to our ownership in HEC properties in Colorado and Arkansas, which we acquired on December 23, 2010. At December 31, 2010, HEC properties had proved developed and total proved reserves of 2,803 MBoe and 9,339 MBoe, respectively, and a PV-10 value of $113.1 million.

(3) Determined using the ratio of 6 Mcf of natural gas being equivalent to one Bbl of crude oil.

(4) PV-10 is a non-GAAP financial measure and represents the present value of estimated future cash inflows from proved crude oil and natural gas reserves, less future development and production costs, discounted at 10% per annum to reflect timing of future cash inflows and using the twelve month unweighted arithmetic average of the first-day-of-the-month price for each of the preceding twelve months. PV-10 differs from Standardized Measure because it does not include the effect of future income taxes. A reconciliation of our Standardized Measure of Discounted Net Cash Flows to PV-10 is provided under " *Non-GAAP Financial Measures and Reconciliation PV-10*," below.

12

Table of Contents

	Bonanza Creek Energy Company, LLC (Predecessor)				Bonanza Creek Energy, Inc.		Holmes Eastern Company, LLC	Bonanza Creek Energy, Inc. Pro Forma[2]
	Year Ended December 31,		Period Ended December 23,	Nine Months Ended September 30,	Period from Inception (December 23, 2010) to December 31,	Nine Months Ended September 30,	Period Ended December 23,	Year Ended December 31,
	2008	2009	2010[1]	2010	2010	2011	2010[1]	2010
Net Sales Data:								
Crude oil (MBbls)	453.7	507.4	469.0	342.5	15.9	634.4	129.1	614.1
Natural gas (MMcf)	668.9	939.0	1,308.5	969.1	43.0	1,822.8	780.6	2,132.2
Natural gas liquids (MBbls)	35.5	69.1	126.5	91.8	3.3	128.8	8.7	138.4
CO_2 (MMcf)	663.0	217.1	533.1	464.3	4.5	232.0		537.6
Crude oil equivalent (MBoe)[3]	600.7	733.0	813.6	595.7	26.4	1,066.9	267.9	1,107.9
Average daily volumes (Boe/day)[3]	1,641	2,008	2,279	2,182	3,297	3,908	750	3,035
Average Sales Price (Before Hedging)[4]:								
Crude oil (per Bbl)	$ 88.09	$ 54.40	$ 73.41	$ 71.29	$ 83.24	$ 90.13	$ 74.78	$ 73.95
Natural gas (per Mcf)	7.72	3.91	4.76	4.96	4.80	5.09	4.89	4.81
Natural gas liquids (per Bbl)	57.45	41.77	56.04	54.09	63.42	68.56	55.46	56.18
CO_2 (per Mcf)	1.12	1.30	1.09	1.09	1.12	1.07		1.09
Average equivalent price (per Boe)[3]	78.53	46.60	58.69	57.38	65.98	70.57	52.10	57.27
Average Sales Price (After Hedging)[4]:								
Crude oil (per Bbl)	$ 79.59	$ 67.40	$ 75.07	$ 73.34	$ 81.18	$ 85.67	$ 74.78	$ 74.47
Natural gas (per Mcf)	7.93	5.05	5.01	5.51	4.48	5.36	4.89	5.16
Natural gas liquids (per Bbl)	57.45	41.77	56.04	54.09	63.42	68.56	55.46	56.18
CO_2 (per Mcf)	1.12	1.30	1.09	1.09	1.12	1.07		1.09
Average equivalent price (per Boe)[3]	72.35	57.07	60.05	59.45	64.21	68.36	52.10	58.22
Expenses (per Boe)[3]:								
Lease operating expenses	$ 34.02	$ 18.35	$ 18.18	$ 17.76	$ 18.31	$ 13.55	$ 7.50	$ 15.60
Severance and ad valorem taxes	3.07	2.93	1.99	1.77	2.65	3.62	3.11	2.28
General and administrative	12.45	10.38	13.22	10.56	12.27	8.54	2.37	10.58
Depreciation, depletion and amortization	42.39	19.25	17.48	19.40	19.20	19.76	11.22	15.85

(1) We completed our Corporate Restructuring on December 23, 2010. The operating results of BCEC for the period ended December 23, 2010 are included in the results presented above.

(2) Pro forma for our Corporate Restructuring as if it had occurred as of January 1, 2010.

(3) Does not include data relating to sales of CO_2.

(4) Although we do not designate our derivatives as cash flow hedges for financial statement purposes, the derivatives do economically hedge the price we receive for crude oil and natural gas.

Non-GAAP Financial Measures and Reconciliation

Adjusted EBITDAX

Adjusted EBITDAX is a supplemental non-GAAP financial measure that is used by management and external users of our consolidated financial statements, such as industry analysts, investors, lenders and

Table of Contents

rating agencies and is not a measure of net income or cash flows as determined by United States generally accepted accounting principles, or GAAP.

We define Adjusted EBITDAX as earnings before interest expense, income taxes, depreciation, depletion and amortization, property impairments, exploration expenses, unrealized derivative gains and losses, non-cash stock-based compensation expense and the other items listed below.

Management believes Adjusted EBITDAX is useful because it allows them to more effectively evaluate our operating performance and compare the results of our operations from period to period without regard to our financing methods or capital structure. We exclude the items listed above from net income in arriving at Adjusted EBITDAX because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. Adjusted EBITDAX should not be considered as an alternative to, or more meaningful than, net income or cash flows from operating activities as determined in accordance with GAAP or as an indicator of our operating performance or liquidity. Certain items excluded from Adjusted EBITDAX are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure, as well as the historic costs of depreciable assets, none of which are components of Adjusted EBITDAX. Our computations of Adjusted EBITDAX may not be comparable to other similarly titled measures of other companies. We believe that Adjusted EBITDAX is a widely followed measure of operating performance and may also be used by investors to measure our ability to meet debt service requirements.

The following tables present a reconciliation of the non-GAAP financial measure of Adjusted EBITDAX to the GAAP financial measures of net income (loss) and net cash provided by (used in) operating activities, respectively.

	Bonanza Creek Energy Company, LLC (Predecessor)				**Bonanza Creek Energy, Inc.**	
	Year Ended December 31,					
	2008	**2009**	**Period Ended December 23, 2010[1]**	**Nine Months Ended September 30, 2010**	**Period from Inception (December 23, 2010) to December 31, 2010**	**Nine Months Ended September 30, 2011**
	(in thousands)					
Adjusted EBITDAX Reconciliation to Net Income (Loss):						
Net income (loss)	$ 68,754	$ (129,783)	$ 14,784	$ 11,142	$ (162)	$ 12,868
Changes in unrealized (gain) loss on derivative instruments	(119,689)	115,229	(26,740)	(21,149)	514	(7,096)
Change in unrealized loss on derivative liability assumed	(5,403)	(5,439)	(4,407)	(3,371)		
Income taxes					(94)	11,464
Cancelled private placement			2,378	2,378		
(Gain) on sale of properties	(8)	(303)	(4,055)	(4,055)		
Accretion of debt discount	5,986	7,963	8,862	6,556		
Write off of deferred financing costs			1,663	1,663		
Interest expense	12,870	16,582	18,001	13,494	58	2,687
Depreciation, depletion and amortization	25,463	14,108	14,225	11,554	506	21,083
Impairment of oil and gas properties	26,437	579				4,067
Exploration expenses	25	131	360	202		573
Adjusted EBITDAX	$ 14,435	$ 19,067	$ 25,071	$ 18,414	$ 822	$ 45,646

Table of Contents

	Bonanza Creek Energy Company, LLC (Predecessor)				Bonanza Creek Energy, Inc.	
	Year Ended December 31,		Period Ended December 23,	Nine Months Ended September 30,	Period from Inception (December 23, 2010) to December 31,	Nine Months Ended September 30,
	2008	2009	2010[(1)]	2010	2010	2011
	(in thousands)					
Adjusted EBITDAX Reconciliation to Net Cash Provided By (Used In) Operating Activities:						
Net cash provided by (used in) operating activities	$ 11,128	$ 11,134	$ 22,759	$ 14,141	$ (1,633)	$ 37,333
Cancelled private placement			2,378	2,378		
Interest expense for line of credit excluding amortization of deferred financing costs	5,374	5,159	5,368	3,971	42	1,984
Cash exploration expenses	25	131	318	202		573
Other		(138)				(92)
Provision for losses on accounts receivable	(343)					
Changes in working capital	(1,749)	2,781	(5,752)	(2,278)	2,413	5,848
Adjusted EBITDAX	$ 14,435	$ 19,067	$ 25,071	$ 18,414	$ 822	$ 45,646

(1) We completed our Corporate Restructuring on December 23, 2010. The operating results of BCEC for the period ended December 23, 2010 are included in the results presented above.

PV-10

PV-10 is a non-GAAP financial measure and represents the present value of estimated future cash inflows from proved oil and natural gas reserves, less future development and production costs, discounted at 10% per annum to reflect timing of future cash inflows and using the twelve month unweighted arithmetic average of the first-day-of-the-month price for each of the preceding twelve months. PV-10 differs from Standardized Measure because it does not include the effects of income taxes. 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.

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

	Bonanza Creek Energy Company, LLC (Predecessor)			Holmes Eastern Company, LLC	Bonanza Creek Energy, Inc. Pro Forma
	As of December 31,			As of December 31,	As of December 31,
(in millions)	2008[(1)]	2009	2010	2010	2010
PV-10	$ 84.7	$ 208.2	$ 346.6	$ 115.0	$ 461.6
Estimated taxes[(2)]	(0.8)	(22.5)	(61.5)	(25.3)	(86.9)
Standardized measure	$ 83.9	$ 185.7	$ 285.1	$ 89.7	$ 374.7

(1) As of December 31, 2008 the PV-10, estimated taxes, and Standardized Measure were significantly lower than these metrics as of December 31, 2009 due to SEC reserve pricing of $44.60 per Bbl as of December 31, 2008 as compared to $61.18 per Bbl as of December 31, 2009. Income taxes were further reduced as of December 31, 2008 due to a significant acquisition that took place during

2008 that added significant future income tax deductions for cost depletion and tangible well head equipment depreciation.

(2) Our predecessor, BCEC, was a partnership for federal income tax purposes and, therefore, was not subject to entity-level taxation. Historically, federal or state corporate income taxes have been passed through to BCEC's members. However, as a corporation, we are subject to U.S. federal and state income taxes. The estimated taxes shown above illustrate the effect of income taxes on net revenues as of December 31, 2008, 2009 and 2010, assuming we had been subject to entity-level tax and further assuming an estimated combined 38.5% federal and state income tax rate.

Table of Contents

RISK FACTORS

An investment in our common stock involves risks. You should carefully consider the risks described below before investing in our common stock. The risks and uncertainties described below are not the only ones we may face. The following risks, together with additional risks and uncertainties not currently known to us or that we may currently deem immaterial, could impair our financial position and results of operations.

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

Our future revenues are dependent on our ability to successfully replace our proved producing reserves.

In general, production from oil and gas properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Our current proved reserves will decline as reserves are produced and, therefore, our level of production and cash flows will be affected adversely unless we conduct successful exploration and development activities or acquire properties containing proved reserves. Thus, our future oil and natural gas production and, therefore, our cash flow and income are highly dependent upon our level of success in finding or acquiring additional reserves. However, we cannot assure you that our future acquisition, development and exploration activities will result in any specific amount of additional proved reserves or that we will be able to drill productive wells at acceptable costs.

Exploration and development activities involve numerous risks, including the risk that no commercially productive oil or gas reservoirs will be discovered. In addition, the future cost and timing of drilling, completing and producing wells is often uncertain. Furthermore, drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- lack of acceptable prospective acreage;
- inadequate capital resources;
- reductions in oil and natural gas prices;
- unexpected drilling conditions, including pressure or irregularities in formations and equipment failures or accidents;
- adverse weather conditions, such as blizzards and ice storms;
- unavailability or high cost of drilling rigs, equipment or labor;
- title problems;
- compliance with governmental regulations;
- delays imposed by or resulting from compliance with regulatory requirements; and
- mechanical difficulties.

According to estimates included in our December 31, 2010 proved reserve report, if on January 1, 2011 we had ceased all drilling and development, including recompletions, refracs and workovers, then our proved developed producing reserves base would decline at an annual effective rate of 7.7% over 10 years, including 31.7% during the first year. If we fail to replace reserves through drilling, our level of production and cash flows will be affected adversely. Our total proved reserves will decline as reserves are produced unless we conduct other successful exploration and development activities or acquire properties containing proved reserves, or both.

A decline in oil and natural gas prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments.

The price we receive for our oil and natural gas heavily influences our revenue, profitability, access to capital and future rate of growth. Oil and natural gas are commodities and, therefore, their prices are

Table of Contents

subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil and natural gas have been volatile. These markets will likely continue to be volatile in the future. The prices we receive for our production, and the levels of our production, depend on numerous factors beyond our control. These factors include the following:

- worldwide and regional economic and political conditions impacting the global supply and demand for oil and natural gas;
- the price and quantity of imports of foreign oil and natural gas;
- the level of global oil and natural gas exploration and production;
- the level of global oil and natural gas inventories;
- localized supply and demand fundamentals and transportation availability;
- weather conditions and natural disasters;
- domestic and foreign governmental regulations;
- speculation as to the future price of oil and the speculative trading of oil and natural gas futures contracts;
- price and availability of competitors' supplies of oil and natural gas;
- the actions of the Organization of Petroleum Exporting Countries, or OPEC;
- technological advances affecting energy consumption; and
- the price and availability of alternative fuels.

Further, oil prices and natural gas prices do not necessarily fluctuate in direct relationship to each other. Because approximately 68.1% of our estimated proved reserves as of December 31, 2010 were oil and natural gas liquids reserves, our financial results are more sensitive to movements in oil prices. The price of oil has been extremely volatile, and we expect this volatility to continue. During the year ended December 31, 2010, the daily NYMEX WTI oil spot price ranged from a high of $89.28 per Bbl to a low of $74.52 per Bbl, and the NYMEX natural gas Henry Hub spot price ranged from $5.60 to $3.62 per MMBtu.

Substantially all of our oil production is sold to purchasers under short-term (less than twelve months) contracts at market based prices. Lower oil and natural gas prices will reduce our cash flows, borrowing ability and the present value of our reserves. Lower prices may also reduce the amount of oil and natural gas that we can produce economically and may affect our proved reserves.

Additionally, as of October 31 we had commodity price hedging agreements on approximately 36% of our estimated Boe production. To the extent we are unhedged or our hedge parties default in their obligations, we have significant exposure to adverse changes in the prices of oil and natural gas that could materially and adversely affect our results of operations.

Our identified drilling locations are scheduled to be developed over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

Our management team has identified and scheduled drilling locations on our acreage over a multi-year period. Our ability to drill and develop these locations depends on a number of factors, including the availability of capital, seasonal conditions, regulatory approvals, oil and natural gas prices, costs and drilling results. The final determination on whether to drill any of these drilling locations will be dependent upon the factors described elsewhere in this prospectus as well as, to some degree, the results of our drilling activities with respect to our proved drilling locations. Because of these uncertainties, we do not know if the drilling locations we have identified will be drilled within our expected time-frame or will

Table of Contents

ever be drilled. As such, our actual drilling activities may be materially different from those presently identified, which could adversely affect our business, results of operations or financial condition.

Certain of our undeveloped leasehold acreage is subject to leases that will expire over the next several years unless production is established on units containing the acreage.

The terms of certain of our oil and gas leases stipulate that the lease will terminate if not held by production. As of October 31, 2010, 30,296 net acres of our properties in the Rocky Mountain region, specifically 5,476 acres in the DJ Basin and 24,820 acres in the North Park Basin, were not held by production. For these properties, if production in paying quantities is not established on units containing these leases during the next three years, then 6,361 net acres will expire in 2011, 3,695 net acres will expire in 2012 and 11,143 net acres will expire in 2013. If our leases expire, we will lose our right to develop the related properties.

Our drilling plans for these areas are subject to change based upon various factors, many of which are beyond our control, including drilling results, oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints, and regulatory approvals. Further, some of our acreage is located in governmental sections where we do not hold the majority of the acreage and therefore it is likely that we will not be named operator of these sections. As a non-operating leaseholder we have less control over the timing of drilling and there is therefore additional risk of expirations occurring in sections where we are not the operator. For certain properties in which we are a non-operating leaseholder, we have the right to propose the drilling of wells pursuant to a joint operating agreement. Those properties that are not subject to a joint operating agreement are located in states where state law grants us the right to force pooling, except for our properties located in California, where state law does not grant the right to force pooling.

Our estimated proved reserves are based on many assumptions that may turn out to be inaccurate. Any significant inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

Reserve engineering is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact manner. It requires interpretations of available technical data and many assumptions, including assumptions relating to current and future economic conditions and commodity prices. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of reserves shown in this prospectus.

In order to prepare our estimates, we must project production rates and the timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data; the quality and reliability of this data can vary. The process also requires economic assumptions about matters such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves 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 oil and natural gas prices and other factors, many of which are beyond our control.

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

You should not assume that the present value of future net revenues from our proved reserves is the current market value of our estimated oil and natural gas reserves. For the year ended December 31, 2008, we based the estimated discounted future net revenues from our proved reserves on prices and costs in effect at year end in accordance with previous SEC requirements. In accordance with SEC requirements for the years ended December 31, 2009 and 2010, we have based the estimated discounted future net revenues from our proved reserves on the twelve month unweighted arithmetic average of the first-day-of-the-month price for each of the preceding twelve months without giving effect to derivative transactions. Actual future net revenues from our oil and natural gas properties will be affected by factors such as:

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

The timing of both our production and our incurrence of expenses in connection with the development and production of oil and natural gas properties will affect the timing and amount of actual future net revenues from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net revenues may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general.

Actual future prices and costs may differ materially from those used in the present value estimates included in this prospectus. If oil prices decline by $10.00 per Bbl, then our PV-10 as of December 31, 2010 would decrease by approximately $100.4 million. If natural gas prices decline by $1.00 per Mcf, then our PV-10 as of December 31, 2010 would decrease by approximately $32.9 million.

We have incurred losses from operations during certain periods since our inception and may continue to do so in the future.

We incurred net operating losses of $33.8 million and $3.6 million in the years ended December 31, 2008 and 2009, respectively. Our development of, and participation in, a large number of prospects in the future will require substantial capital expenditures. The uncertainty and factors described throughout this section may impede our ability to economically find, develop, exploit, and acquire oil and natural gas reserves. As a result, we may not be able to achieve or sustain profitability or positive cash flows from operating activities in the future.

Part of our strategy involves drilling in existing or emerging shale plays using the latest available horizontal drilling and completion techniques; therefore, the results of our planned exploratory drilling in these plays are subject to drilling and completion technique risks and drilling results may not meet our expectations for reserves or production.

Our operations involve utilizing the latest drilling and completion techniques as developed by us and our service providers in order to maximize cumulative recoveries and therefore generate the highest possible returns. Risks that we face while drilling include, but are not limited to, landing our well bore in the desired drilling zone, staying in the desired drilling zone while drilling horizontally through the formation, running our casing the entire length of the well bore and being able to run tools and other equipment consistently through the horizontal well bore. Risks that we face while completing our wells include, but are not limited to, being able to fracture stimulate the planned number of stages, being able to run tools the entire length of the well bore during completion operations and successfully cleaning out the well bore after completion of the final fracture stimulation stage.

The results of our drilling in new or emerging formations, such as the Niobrara oil shale, are more uncertain initially than drilling results in areas that are more developed and have a longer history of established production. Newer or emerging formations and areas have limited or no production history and consequently we are less able to predict future drilling results in these areas.

Ultimately, the success of these drilling and completion techniques can only be evaluated over time as more wells are drilled and production profiles are established over a sufficiently long time period. If our drilling results are less than anticipated or we are unable to execute our drilling program because of capital constraints, lease expirations, access to gathering systems and limited takeaway capacity or otherwise, and/or natural gas and oil prices decline, the return on our investment in these areas may not be as attractive as we anticipate. Further, as a result of any of these developments we could incur material write-downs of our oil and gas properties and the value of our undeveloped acreage could decline in the future.

Our exploration, development and exploitation projects require substantial capital expenditures. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a decline in our crude oil and natural gas reserves.

The crude oil and natural gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures in our business for the development, exploitation, production and acquisition of crude oil and natural gas reserves. In 2010, we had $35.5 million of capital and exploration expenditures. Our capital expenditures for 2011 are budgeted to be approximately $162.1 million with $141.3 million allocated for the development and operation of our oil and gas properties. The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things, commodity prices, actual drilling results, the availability of drilling rigs and other services and equipment, and regulatory, technological and competitive developments. In response to continued improvement in commodity prices we may increase our actual capital expenditures. We intend to finance our future capital expenditures primarily through our cash flows from operations, borrowings under our credit facility and the proceeds from this offering; however, our financing needs may require us to alter or increase our capitalization substantially through the issuance of debt or equity securities or the sale of assets.

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

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

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

Borrowings under our credit facility are limited by our borrowing base, which is subject to periodic redetermination.

The borrowing base under our credit facility is redetermined semi-annually. Redeterminations are based upon a number of factors, including commodity prices and reserve levels. In addition, our lenders have substantial flexibility to reduce our borrowing base due to subjective factors. Upon a redetermination, we could be required to repay a portion of our bank debt to the extent our outstanding borrowings at such time exceed the redetermined borrowing base. We may not have sufficient funds to make such repayments, which could result in a default under the terms of the facility and an acceleration of the loans thereunder.

Our level of indebtedness may increase, reducing our financial flexibility.

We intend to fund our capital expenditures through our cash flow from operations, borrowings under our credit facility and the proceeds from this offering. Our ability to make the necessary capital investment to maintain or expand our asset base of oil and natural gas reserves will be impaired if cash flow from operations is reduced and external sources of capital become limited or unavailable. If we incur additional debt for these or other purposes, the related risks that we now face could intensify. Our level of debt could affect our operations in several important ways, including the following:

- a portion of our cash flow from operations would be used to pay interest on borrowings;
- the covenants contained in our credit facility limit our ability to borrow additional funds, pay dividends, dispose of assets or issue shares of preferred stock and otherwise may affect our flexibility in planning for, and reacting to, changes in business conditions;
- a high level of debt may impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, general corporate or other purposes;
- a leveraged financial position would make us more vulnerable to economic downturns and decreases in commodity prices, and could limit our ability to withstand competitive pressures; and
- any debt that we incur under our credit facility would be at variable rates which could make us vulnerable to increases in interest rates.

The development and exploitation of certain of our resources is dependent on the funding and construction of additional gas processing capacity.

Our pipeline system that transports the natural gas produced from our properties in the Dorcheat Macedonia and McKamie Patton fields to our gas processing facilities does not have sufficient capacity to deliver anticipated increased volumes of natural gas from further development of the field. As a result, in order to fully develop and exploit our opportunities within the Dorcheat Macedonia and McKamie Patton fields we must construct additional gas processing capacity. Our inability to fund, or timely construct, additional gas processing capacity to service production from the Dorcheat Macedonia and McKamie Patton fields will limit our growth and could materially and adversely affect our results of operations.

Our ability to sell our production and/or receive market prices for our production may be adversely affected by lack of transportation, capacity constraints and interruptions.

The marketability of our production from the Mid-Continent, Rocky Mountain and California regions depends in part upon the availability, proximity and capacity of third-party refineries, natural gas gathering systems and processing facilities. We deliver crude oil and natural gas produced from these areas through trucking services and pipelines that we do not own. The lack of availability or capacity on these systems and facilities could reduce the price offered for our production or result in the shut-in of producing wells or the delay or discontinuance of development plans for properties.

A portion of our production may also be interrupted, or shut in, from time to time for numerous other reasons, including as a result of accidents, field labor issues or strikes, or we might voluntarily curtail production in response to market conditions. If a substantial amount of our production is interrupted at the same time, it could adversely affect our cash flow.

Currently there are no natural gas pipeline systems that service wells in the North Park Basin, which is prospective for the Niobrara oil shale. In addition, we are not aware of any plans to construct a facility necessary to process natural gas produced from this basin. If neither we nor a third party constructs the required pipeline system and processing facility, we may not be able to fully develop our resources in the North Park Basin.

Increased costs of capital could adversely affect our business.

Our business and operating results can be harmed by factors such as the availability, terms and cost of capital and increases in interest rates. Changes in any one or more of these factors could cause our cost of doing business to increase, limit our access to capital, limit our ability to pursue acquisition opportunities, reduce our cash flows available for drilling and place us at a competitive disadvantage. Continuing disruptions and volatility in the global financial markets may lead to an increase in interest rates or a contraction in credit availability impacting our ability to finance our operations. We require continued access to capital. A significant reduction in the availability of credit could materially and adversely affect our ability to achieve our planned growth and operating results.

If oil and natural gas prices decrease, we may be required to take write-downs of the carrying values of our oil and natural gas properties.

We review our proved oil and natural gas properties for impairment whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. Based on specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write down the carrying value of our oil and natural gas properties, which may result in a decrease in the amount available under our credit facility. A write-down constitutes a non-cash charge to earnings. We may incur impairment charges in the future which could have a material adverse effect on our ability to borrow under our credit facility and our results of operations for the periods in which such charges are taken.

Operating hazards, natural disasters or other interruptions of our operations could result in potential liabilities, which may not be fully covered by our insurance.

The oil and gas business generally, and our operations, are subject to certain operating hazards such as:

- well blowouts;
- cratering (catastrophic failure);
- explosions;
- uncontrollable flows of oil, gas or well fluids;
- fires;
- oil spills;
- pollution;

releases of toxic gas (including releases at our gas processing facilities) or of other substances such as petroleum liquids or drilling fluids, into the environment; and

hazards resulting from the presence of hydrogen sulfide (H_2S) or other contaminants in gas we produce.

At one of our Arkansas properties, we produce a small amount of gas from eight operated (gross) wells where we have identified the presence of H_2S at levels which would be hazardous in the event of an uncontrolled gas release or unprotected exposure. In addition, our operations in Arkansas are susceptible to damage from natural disasters such as flooding or tornados, which involve increased risks of personal injury, property damage and marketing interruptions. The occurrence of one of these operating hazards may result in injury, loss of life, suspension of operations, environmental damage and remediation and/or governmental investigations and penalties. The payment of any of these liabilities could reduce, or even eliminate, the funds available for exploration and development, or could result in a loss of our properties.

Our insurance might be inadequate to cover our liabilities. Insurance costs are expected to continue to increase over the next few years, and we may decrease coverage and retain more risk to mitigate future cost increases. If we incur substantial liability, and the damages are not covered by insurance or are in excess of policy limits, then our business, results of operations and financial condition may be materially adversely affected.

We carry insurance to reduce our exposure to sudden and accidental environmental contamination but do not have coverage for gradual, long-term contamination. Our policies include operator's extra expense ("OEE") coverage with a $1.0 million limit per occurrence; commercial general liability ("CGL") coverage with a time element pollution limit of $1.0 million per occurrence and in the aggregate; and excess liability coverage with a $10.0 million limit per occurrence and in the aggregate. Our OEE policy provides primary coverage for the cleanup of polluting or contaminating substances caused by a sudden and accidental loss of control of a well at the surface. The CGL and Excess Liability policies also provide sudden and accidental pollution liability coverage, including coverage in excess of the OEE policy limit for pollution caused by a well out of control at the surface. In order to obtain coverage, we must report the event to the insurance company within 90 days after its commencement. The CGL policy also contains a $1.0 million aggregate limit for damage to oil, gas, water or other mineral substances that have not been reduced to physical possession above the surface.

Since hydraulic fracturing activities are part of our operations, they are covered by our insurance against claims made for bodily injury, property damage and clean up costs stemming from a sudden and accidental pollution event, provided that we report the event within 90 days after its commencement. We may not have coverage if the operator is unaware of the pollution event and unable to report the "occurrence" to the insurance company within the required time frame. Nor do we have coverage for gradual, long-term pollution events.

Under certain circumstances, we have agreed to indemnify third parties against losses resulting from our operations. Pursuant to our surface leases, we typically indemnify the surface owner for clean up and remediation of the site. As owner and operator of oil and gas wells and associated gathering systems and pipelines, we typically indemnify the drilling contractor for pollution emanating from the well, while the contractor indemnifies us against pollution emanating from its equipment.

Competition in the oil and natural 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 oil and gas and securing equipment and trained personnel. As a relatively small oil and gas company, many of our competitors, major and large independent oil and gas companies, 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 or 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. 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 may incur losses as a result of title deficiencies.

We purchase working and revenue interests in oil and natural gas leasehold interests from third parties or directly from the mineral fee owners. The existence of a material title deficiency can render a lease worthless and can adversely affect our results of operations and financial condition. Title insurance covering mineral leaseholds is not generally available and, in all instances, we forego the expense of retaining lawyers to examine the title to the mineral interest to be placed under lease or already placed under lease until the drilling block is assembled and ready to be drilled, except in Arkansas where we have commenced drilling without complete legal examination of title. As is customary in our industry, we rely upon the judgment of oil and natural gas lease brokers, in-house landmen or independent landmen who perform the field work in examining records in the appropriate governmental offices and abstract facilities before attempting to acquire or place under lease a specific mineral interest. We do not always perform curative work to correct deficiencies in the marketability of the title to us. Except for our properties in Arkansas, we obtain title opinions for specific drilling locations prior to the commencement of drilling. In Arkansas, we have commenced drilling but are in the process of obtaining title opinions. In cases involving more serious title problems, the amount paid for affected oil and natural gas leases can be lost, and the target area can become undrillable. We may be subject to litigation from time to time as a result of title issues.

Seasonal weather conditions and lease stipulations adversely affect our ability to conduct drilling activities in some of the regions where we operate.

Oil and natural gas operations in the Rocky Mountains are adversely affected by seasonal weather conditions and lease stipulations designed to protect various wildlife. In certain areas on federal lands, drilling and other oil and natural gas activities can only be conducted during limited times of the year. These restrictions limit our ability to operate in those areas and can potentially intensify competition for drilling rigs, oil field equipment, services, supplies and qualified personnel, which may lead to periodic shortages. These constraints and the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs.

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, 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 condition, results of operations and future growth. We currently have employment agreements with our executive officers and other key employees. 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.

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

To achieve more predictable cash flows and to reduce our exposure to adverse fluctuations in the prices of oil and natural gas, we currently, and may in the future, enter into derivative arrangements, subject to certain limitations pursuant to our credit facility, for a portion of our oil and natural gas production, including collars and fixed-price swaps. We have not designated any of our derivative instruments as hedges for accounting purposes and record all derivative instruments on our balance sheet at fair value. Changes in the fair value of our derivative instruments are recognized in earnings.

Accordingly, our earnings may fluctuate significantly as a result of changes in the fair value of our derivative instruments.

Derivative arrangements also expose us to the risk of financial loss in some circumstances, including when:

- production is less than the volume covered by the derivative instruments;
- the counter-party to the derivative instrument defaults on its contractual obligations; or
- there is an increase in the differential between the underlying price in the derivative instrument and actual prices received.

In particular, the counterparties on all of our commodity hedging arrangements are either BNP Paribas or Société Générale. Our risk of counterparty default may be impacted to the extent that these banks are exposed to losses as a result of the current European sovereign debt crisis or other future economic events.

In addition, these types of derivative arrangements limit the benefit we would receive from increases in the prices for oil and natural gas.

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

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

The credit default of one of our customers could have a temporary adverse effect on us.

Our revenues are generated under contracts with a limited number of customers. Our results of operations would be adversely affected as a result of non-performance by our two largest customers, which represent 47% and 39%, respectively, of our 2010 total revenues. A non-payment default by one of these large customers could have an adverse effect on us, temporarily reducing our cash flow.

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

On September 12, 2011, President Obama sent to Congress a legislative package that includes proposed legislation that, if enacted into law, would eliminate certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. These proposals also were included in President Obama's Proposed Fiscal Year 2012 Budget. Such changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and gas properties; (ii) the elimination of current deductions for intangible drilling and development costs; (iii) the elimination of the deduction for certain U.S. production activities; and (iv) an extension of the amortization period for certain geological and geophysical expenditures. Recently, members of the U.S. Congress have considered similar changes to the existing federal income tax laws that affect oil and gas exploration and production companies, which, if enacted, would negatively affect our financial condition and results of operations. The passage of any legislation as a result of the budget proposal or any other similar change in U.S. federal income tax law could eliminate or defer certain tax deductions within the industry that are currently available with respect to oil and gas exploration and development, and any such change could negatively affect our financial condition and results of operations.

Our operations are subject to health, safety and environmental laws and regulations which may expose us to significant costs and liabilities.

Our oil and natural gas exploration, production and processing operations are subject to stringent and complex federal, state and local laws and regulations governing health and safety aspects of our operations, the discharge of materials into the environment and the protection of the environment. These laws and regulations may impose on our operations numerous requirements, including the obligation to obtain a permit before conducting drilling or underground injection activities; restrictions on the types, quantities and concentration of materials that may be released into the environment; limitations or prohibitions of drilling activities on certain lands lying within wilderness, wetlands and other protected areas; specific health and safety criteria to protect workers; and the responsibility for cleaning up any pollution resulting from operations. Numerous governmental authorities such as the U.S. Environmental Protection Agency, or the EPA, and analogous state agencies have the power to enforce compliance with these laws and regulations and the permits issued under them, oftentimes requiring difficult and costly actions. Failure to comply with these laws and regulations may result in the assessment of administrative, civil or criminal penalties; the imposition of investigatory or remedial obligations; the issuance of injunctions limiting or preventing some or all of our operations; and delays in granting permits and cancellation of leases.

There is an inherent risk of incurring significant environmental costs and liabilities in the performance of our operations, some of which may be material, due to our handling of petroleum hydrocarbons and wastes, our emissions to air and water, the underground injection or other disposal of our wastes, the use of hydraulic fracturing fluids and historical industry operations and waste disposal practices. Under certain environmental laws and regulations, we may be liable regardless of whether we were at fault for the full cost of removing or remediating contamination, even when multiple parties contributed to the release and the contaminants were released in compliance with all applicable laws. In addition, accidental spills or releases on our properties may expose us to significant liabilities that could have a material adverse effect on our financial condition or results of operations. Aside from government agencies, the owners of properties where our wells are located, the operators of facilities where our petroleum hydrocarbons or wastes are taken for reclamation or disposal and other private parties may be able to sue us to enforce compliance with environmental laws and regulations, collect penalties for violations or obtain damages for any related personal injury or property damage. Some sites we operate are located near current or former third-party oil and natural gas operations or facilities, and there is a risk that contamination has migrated from those sites to ours. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly material handling, emission, waste management or cleanup requirements could require us to make significant expenditures to attain and maintain compliance or may otherwise have a material adverse effect on our own results of operations, competitive position or financial condition. We may not be able to recover some or any of these costs from insurance.

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

Our operations utilize hydraulic fracturing, an important and commonly used process in the completion of oil and natural gas wells in low-permeability formations. This process involves the injection of water, proppant and chemicals under pressure into rock formations to stimulate oil and natural gas production. Some activists have attempted to link fracturing to various environmental problems, including adverse effects to drinking water supplies as well as migration of methane and other hydrocarbons. As a result, several federal agencies are studying any environmental risk with respect to hydraulic fracturing or evaluating whether to restrict its use. Legislation has been introduced in the United States Congress called the Fracturing Responsibility and Awareness of Chemicals Act (the "FRAC Act") that would amend the federal Safe Drinking Water Act ("SDWA") to eliminate an existing exemption for hydraulic fracturing activities from the definition of "underground injection," thereby requiring the oil and natural gas industry to obtain permits for fracturing, and to require disclosure of the chemicals used in the process. If adopted, this legislation could establish an additional level of regulation and permitting at the federal level. At this time, it is not clear what action, if any, the United States Congress will take on the FRAC Act. Scrutiny of hydraulic fracturing activities continues in other ways, with the EPA having commenced a multi-year study of the potential environmental impacts of hydraulic fracturing, the initial results of which are anticipated to be available by late 2012. In addition, on October 21, 2011, the EPA announced its intention to propose regulations by 2014 under the federal Clean Water Act to regulate wastewater discharges from hydraulic fracturing and other natural gas production. The U.S. Department of the Interior has also announced its intention to propose a new rule regulating hydraulic fracturing activities on federal lands, including requirements for disclosure, well bore integrity and handling of flowback water, which, if adopted, would affect our operations on federal lands. In addition to these federal initiatives, several state and local governments have moved to require disclosure of fracturing fluid components or otherwise to regulate their use more closely, including states in which we operate (Colorado, California and Arkansas). In certain areas of the country, new drilling permits for hydraulic fracturing have been put on hold pending development of additional standards. The adoption of any future federal, state or local laws or implementing regulations imposing permitting or reporting obligations on, or otherwise limiting, the hydraulic fracturing process could make it more difficult and more expensive to complete oil and natural gas wells in low-permeability formations and increase our costs of compliance and doing business, as well as delay or prevent the development of unconventional gas resources from shale formations which are not commercial without the use of hydraulic fracturing.

Climate change laws and regulations restricting emissions of "greenhouse gases" could result in increased operating costs and reduced demand for the oil and natural gas that we produce while the physical effects of climate change could disrupt our production and cause us to incur significant costs in preparing for or responding to those effects.

There is a growing belief that emissions of greenhouse gases ("GHG") may be linked to climate change. Climate change and the costs that may be associated with its impacts and the regulation of GHG have the potential to affect our business in many ways, including negatively impacting the costs we incur in providing our products and services and the demand for and consumption of our products and services (due to change in both costs and weather patterns).

In December 2009, the EPA determined that atmospheric concentrations of carbon dioxide, methane, and certain other GHG present an endangerment to public health and welfare because such gases are, according to EPA, contributing to the warming of the Earth's atmosphere and other climatic changes. Consistent with its findings, EPA has proposed or adopted various regulations under the Clean Air Act to address GHG. Among other things, the Agency is limiting emissions of GHG from new cars and light duty trucks beginning with the 2012 model year. In addition, EPA has published a final rule to address the permitting of GHG emissions from stationary sources under the Prevention of Significant Deterioration, or "PSD," and Title V permitting programs, pursuant to which these permitting requirements have been "tailored" to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting. Facilities required to obtain PSD permits for their GHG emissions will be required to meet emissions limits that are based on the "best available control technology," which will be established by the permitting agencies on a case-by-case basis. EPA has also adopted regulations requiring the reporting of GHG emissions from specified large GHG emission sources in the United States, including certain oil and natural gas production facilities, which include certain of our operations, beginning in 2012 for emissions occurring in 2011 and which may form the basis for further regulation. Many of EPA's GHG rules are subject to legal challenges, but have not been stayed pending judicial review. Depending on the outcome of such proceedings, such rules may be modified or rescinded or the EPA could develop new rules. EPA's GHG rules could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified facilities.

Moreover, Congress has from time to time considered adopting legislation to reduce emissions of GHG or promote the use of renewable fuels. As an alternative, some proponents of GHG controls have advocated mandating a national "clean energy" standard. In 2011, President Obama encouraged Congress to adopt a goal of generating 80% of U.S. electricity from "clean energy" by 2035 with credit for renewable and nuclear power and partial credit for clean coal and "efficient natural gas"; the President also proposed ending tax breaks for the oil industry. Because of the lack of any comprehensive federal legislative program expressly addressing GHG, there currently is a great deal of uncertainty as to how and when additional federal regulation of GHG might take place and as to whether EPA should continue with its existing regulations in the absence of more specific Congressional direction.

In the meantime, many states, including California, already have taken such measures, which have included renewable energy standards, development of GHG emission inventories and/or cap and trade programs. Cap and trade programs typically work by requiring major sources of emissions or major producers of fuels to acquire and surrender emission allowances, with the number of available allowances reduced each year until the overall GHG emission reduction goal is achieved. These allowances would be expected to escalate significantly in cost over time. The adoption of legislation or regulatory programs to reduce emissions of GHG could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. If we are unable to recover or pass through a significant level of our costs related to complying with climate change regulatory requirements imposed on us, it could have a material adverse effect on our results of operations and financial condition. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Consequently, legislation and regulatory programs to reduce emissions of GHG could have an adverse effect on our business, financial condition and results of operations.

Finally, it should be noted that some scientists have concluded that increasing concentrations of GHG in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms and floods. If any such effects were to occur, they could have an adverse effect on our exploration and production operations. Significant physical effects of climate change could also have an indirect effect on our financing and operations by disrupting the transportation or process-related services provided by midstream companies, service companies or suppliers with whom we have a business relationship. Our insurance may not cover some or any of the damages, losses, or costs that may result from potential physical effects of climate change.

Table of Contents

We will record substantial compensation expense in the financial quarter in which this offering occurs and we may incur substantial additional compensation expense related to our future grants of stock compensation which may have a material negative impact on our operating results for the foreseeable future.

As a result of outstanding stock-based compensation awards that vest upon consummation of this offering, we will incur substantial compensation expense at the close of this offering. In addition, our compensation expenses may increase in the future as compared to our historical expenses because of the costs associated with our existing and anticipated employee stock ownership and stock-based incentive plans. These additional expenses will adversely affect our net income. We cannot determine the actual amount of these new stock-related compensation and benefit expenses at this time because applicable accounting practices generally require that they be based on the fair market value of the options or shares of common stock at the date of the grant; however, we expect them to be significant. We will recognize expenses for our employee stock ownership plan when shares are committed to be released to participants' accounts and will recognize expenses for restricted stock awards and stock options generally over the vesting period of awards made to recipients.

Risks Related to this Offering and our Common Stock

The initial public offering price of our common stock may not be indicative of the market price of our common stock after this offering. In addition, an active liquid trading market for our common stock may not develop and our stock price may be volatile.

Prior to this offering, our common stock was not traded on any market. An active and liquid trading market for our common stock may not develop or be maintained after this offering. Liquid and active trading markets usually result in less price volatility and more efficiency in carrying out investors' purchase and sale orders. The market price of our common stock could vary significantly as a result of a number of factors, some of which are beyond our control. In the event of a drop in the market price of our common stock, you could lose a substantial part or all of your investment in our common stock. The initial public offering price will be negotiated between us, the selling stockholders and representatives of the underwriters, based on numerous factors which we discuss in the "*Underwriters; Conflicts of Interest*" section of this prospectus, and may not be indicative of the market price of our common stock after this offering. Consequently, you may not be able to sell shares of our common stock at prices equal to or greater than the price paid by you in the offering.

The following factors could affect our stock price:

- our operating and financial performance and drilling locations, including reserve estimates;
- quarterly variations in the rate of growth of our financial indicators, such as net income per share, net income and revenues;
- changes in revenue or earnings estimates or publication of reports by equity research analysts;
- speculation in the press or investment community;
- sales of our common stock by us, the selling stockholders or other stockholders, or the perception that such sales may occur;
- general market conditions, including fluctuations in commodity prices; and
- domestic and international economic, legal and regulatory factors unrelated to our performance.

The stock markets in general have experienced extreme volatility that has often been unrelated to the operating performance of particular companies. These broad market fluctuations may adversely affect the trading price of our common stock.

Table of Contents

Purchasers of common stock in this offering will experience immediate and substantial dilution of $ per share.

Based on an assumed initial public offering price of $ per share (the midpoint of the price range set forth on the cover page of this prospectus), purchasers of our common stock in this offering will experience an immediate and substantial dilution of $ per share in the pro forma as adjusted net tangible book value per share of common stock from the initial public offering price, and our pro forma as adjusted net tangible book value as of September 30, 2011 after giving effect to this offering would be $ per share. See "*Dilution*" for a complete description of the calculation of pro forma net tangible book value.

As a result of the reporting and disclosure requirements of a public company under the Exchange Act, the NYSE rules and the requirements of the Sarbanes-Oxley Act of 2002, we will incur significant additional costs and expenses and compliance with these requirements will require a substantial amount of management's time.

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

- institute a more comprehensive compliance function;
- design, establish, evaluate and maintain a system of internal controls over financial reporting in compliance with the requirements of Section 404 of the Sarbanes-Oxley Act of 2002 and the related rules and regulations of the SEC and the Public Company Accounting Oversight Board;
- comply with rules promulgated by the NYSE;
- prepare and distribute periodic public reports in compliance with our obligations under the federal securities laws;
- establish new internal policies, such as those relating to disclosure controls and procedures and insider trading;
- hire additional accounting, finance and legal staff; and
- involve and retain to a greater degree outside counsel and accountants in the above activities.

In addition, we also expect that being a public company subject to these rules and regulations will increase our cost to obtain director and officer liability insurance coverage and could also make it more difficult for us to attract and retain qualified members of our board of directors, particularly to serve on our audit committee, and qualified executive officers.

We do not intend to pay, and we are currently prohibited from paying, dividends on our common stock and, consequently, your only opportunity to achieve a return on your investment is if the price of our stock appreciates.

We do not plan to declare dividends on shares of our common stock in the foreseeable future. Additionally, we are currently prohibited from making any cash dividends pursuant to the terms of our credit facility. Consequently, your only opportunity to achieve a return on your investment in us will be if the market price of our common stock appreciates, which may not occur, and you sell your shares at a profit. There is no guarantee that the price of our common stock that will prevail in the market after this offering will ever exceed the price that you pay.

Future sales of our common stock in the public market could lower our stock price, and any additional capital raised by us through the sale of equity or convertible securities may dilute your ownership in us.

We may sell additional shares of common stock in subsequent public offerings. We may also issue additional shares of common stock or convertible securities. After the completion of this offering, we will have outstanding shares of common stock. This number includes shares that we and the selling stockholders are selling in this offering, which may be resold immediately in the public market. Following the completion of this offering, the selling stockholders will own shares, or approximately % of our total outstanding shares. Each of the selling stockholders is a party to a registration rights agreement with us. Pursuant to this agreement, subject to the terms of the lock-up agreement between the selling stockholders and the underwriters described under the caption "*Underwriters; Conflicts of Interest*," we have agreed to effect the registration of shares held by the selling stockholders if they so request or if we conduct other offerings of our common stock. See "*Certain Relationships and Related Party Transactions Registration Rights Agreement*." In addition, as soon as practicable after this offering, we intend to file a registration statement with the SEC on Form S-8 providing for the registration of additional shares of our common stock issued or reserved for issuance under our stock incentive and compensation plans. Shares registered under this registration statement on Form S-8 will be available for sale in the open market following the effective date, unless such shares are subject to vesting restrictions with us, Rule 144 restrictions applicable to our affiliates or the lock-up agreements described above.

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

The equity trading markets may be volatile, which could result in losses for our stockholders.

In recent years, the stock market has experienced extreme price and volume fluctuations. This volatility has had a significant effect on the market price of securities issued by many companies for reasons unrelated to their operating performance. The market price of our common stock could similarly be subject to wide fluctuations in response to a number of factors, most of which we cannot control, including:

- domestic and worldwide supplies and prices of, and demand for, oil and gas;
- changes in environmental and other governmental regulations affecting the oil and gas industry;
- variations in our quarterly results of operations or cash flows; and
- changes in general conditions in the U.S. economy, financial markets or the oil and gas industry.

The realization of any of these risks and other factors beyond our control could cause the market price of our common stock to decline significantly.

Our certificate of incorporation and bylaws contain, and Delaware law contains, provisions that may prevent, discourage or frustrate attempts to replace or remove our current management by our stockholders, even if such replacement or removal may be in our stockholders' best interests.

The effectiveness of our second amended and restated certificate of incorporation and bylaws is contingent upon this offering and will occur immediately after the conversion of our Class B Common Stock into Class A Common Stock and immediately prior to the consummation of this offering. Our second amended and restated certificate of incorporation and bylaws contain, and Delaware law contains,

Table of Contents

provisions that could enable our management to resist a takeover attempt. Among other things, our second amended and restated certificate of incorporation and bylaws will:

- establish advance notice procedures with regard to stockholder proposals relating to director nominations or new business to be brought before stockholder meetings. These procedures provide that notice of stockholder proposals must be timely given in writing to our corporate secretary prior to the meeting at which the action is to be taken. Generally, to be timely, notice must be received at our principal executive offices not less than 120 days prior to the first anniversary date of the annual meeting for the preceding year. Our bylaws will specify the requirements as to form and content of all stockholder notices. These requirements may preclude stockholders from bringing matters before the stockholders at an annual or special meeting;

- provide our board of directors the ability to authorize undesignated preferred stock and to issue, without stockholder approval, preferred stock with voting or other rights or preferences that could impede the success of any attempt to gain control of us. These and other provisions may have the effect of deterring hostile takeovers or delaying changes in control or management of our company;

- provide for our board of directors to be divided into three classes of directors, with each class as nearly equal in number as possible, serving staggered three year terms, other than directors which may be elected by holders of preferred stock, if any. For more information on the classified board of directors, see "*Management*." This system of electing and removing directors may tend to discourage a third party from making a tender offer or otherwise attempting to obtain control of us, because it generally makes it more difficult for stockholders to replace a majority of the directors;

- provide that the authorized number of directors may be changed only by resolution of the board of directors;

- provide that all vacancies, including newly created directorships, may, except as otherwise required by law, be filled by the affirmative vote of a majority of directors then in office, even if less than a quorum;

- provide that stockholders may only act at a duly called meeting and may not act by written consent in lieu of a meeting;

- provide that special meetings of stockholders may only be called by our board of directors, the Chairperson, the Chief Executive Officer or the President and not by our stockholders; and

- provide that our board of directors may alter or repeal our bylaws or approve new bylaws without further stockholder approval.

These provisions could:

- discourage, delay or prevent a change in the control of our company or a change in our management, even if the change would be in the best interests of our stockholders;

- adversely affect the voting power of holders of common stock; and

- limit the price that investors might be willing to pay in the future for shares of our common stock.

West Face Capital and AIMCo together may be deemed to beneficially own or control a majority of our common stock, giving them a controlling influence over corporate transactions and other matters. Their interests and the interests of the parties on whose behalf they invest may conflict with yours, and the concentration of ownership of our common stock by such stockholders will limit the influence of public stockholders.

Upon completion of this offering, West Face Capital and AIMCo together may be deemed to beneficially own, control or have substantial influence over approximately % of our outstanding common stock, and approximately % if the underwriters exercise their option to purchase additional shares in full. West Face Capital and AIMCo, on behalf of certain of its clients, have entered into an investment management agreement pursuant to which West Face Capital has the right to vote the shares of

Table of Contents

our common stock held by certain clients of AIMCo. West Face Capital also has the right, pursuant to the advisory agreement with Black Bear, to vote the shares held by Black Bear, and accordingly, West Face Capital may exert significant influence over our board of directors and control or substantially influence the outcome of stockholder votes. Even if the investment management agreement between West Face and AIMCo were to be terminated, West Face Capital and AIMCo, on behalf of its clients, voting together as a group would have the ability to exert significant influence over the company.

A concentration of ownership in West Face alone or together with AIMCo's clients would allow such stockholders to control, directly or indirectly and subject to applicable law, significant matters affecting us, including the following:

- establishment of business strategy and policies;
- amendment of our certificate of incorporation or bylaws;
- the payment of dividends on our common stock;
- nomination and election of directors;
- appointment and removal of officers;
- our capital structure; and
- compensation of directors, officers and employees and other employee-related matters.

Such a concentration of ownership may have the effect of delaying, deterring or preventing a change in control, a merger, consolidation, takeover or other business combination, and could discourage a potential acquirer from making a tender offer or otherwise attempting to obtain control of us, which could in turn have an adverse effect on the market price of our common stock.

We expect to be a "controlled company" within the meaning of the NYSE rules and, if applicable, would qualify for and will rely on exemptions from certain corporate governance requirements.

West Face Capital and AIMCo, on behalf of certain of its clients, have entered into an investment management agreement pursuant to which West Face Capital has the right to vote the shares of our common stock held by certain clients of AIMCo. West Face Capital, via the investment management agreement with AIMCo and an advisory agreement with Black Bear, has the power to vote 72.66% of our issued and outstanding common stock prior to this offering, which enables West Face Capital to control the election of directors. Thus, we are a "controlled company" as that term is defined in Section 303A of the NYSE Listed Company Manual. Under the NYSE rules, a "controlled company" may elect not to comply with certain NYSE corporate governance requirements, including:

- the requirement that a majority of our board of directors consist of independent directors;
- the requirement that our nominating and governance committee be composed entirely of independent directors with a written charter addressing the Committee's purpose and responsibilities; and
- the requirement that our compensation committee be composed entirely of independent directors with a written charter addressing the Committee's purpose and responsibilities.

These requirements will not apply to us as long as we remain a "controlled company." The investment management agreement with AIMCo may be terminated upon 90 days prior written notice or immediately in certain circumstances, at which time we would no longer be deemed a "controlled company." Following this offering, we may utilize some or all of the above exemptions. Accordingly, you may not have the same protections afforded to stockholders of companies that are subject to all of the corporate governance requirements of the NYSE. The significant ownership interest of Black Bear and certain clients of AIMCo could adversely affect investors' perceptions of our corporate governance.

Table of Contents

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

The information discussed in this prospectus include "forward-looking statements." These forward-looking statements are identified by their use of terms and phrases such as "may," "expect," "estimate," "project," "plan," "believe," "intend," "achievable," "anticipate," "will," "continue," "potential," "should," "could," and similar terms and phrases. All statements, other than statements of historical facts, included herein concerning, among other things, planned capital expenditures, potential increases in oil and natural gas production, the number of anticipated wells to be drilled after the date hereof, future cash flows and borrowings, pursuit of potential acquisition opportunities, our financial position, business strategy and other plans and objectives for future operations, are forward-looking statements. Although we believe that the expectations reflected in these forward-looking statements are reasonable, they do involve certain assumptions, risks and uncertainties. Our actual results could differ materially from those anticipated in these forward-looking statements as a result of certain factors, including, among others:

- our ability to replace oil and natural gas reserves;
- declines or volatility in the prices we receive for our oil and natural gas;
- our financial position;
- our cash flow and liquidity;
- general economic conditions, whether internationally, nationally or in the regional and local market areas in which we do business;
- the recent economic slowdown that has and may continue to adversely affect consumption of oil and natural gas by businesses and consumers;
- our ability to generate sufficient cash flow from operations, borrowings or other sources to enable us to fully develop our undeveloped acreage positions;
- the presence or recoverability of estimated oil and natural gas reserves and the actual future production rates and associated costs;
- uncertainties associated with estimates of proved oil and gas reserves and, in particular, probable and possible resources;
- the possibility that the industry may be subject to future regulatory or legislative actions (including additional taxes and changes in environmental regulation);
- environmental risks;
- drilling and operating risks;

exploration and development risks;

competition in the oil and natural gas industry;

management's ability to execute our plans to meet our goals;

our ability to retain key members of our senior management and key technical employees;

access to adequate gathering systems and pipeline take-away capacity to execute our drilling program;

our ability to secure firm transportation for oil and natural gas we produce and to sell the oil and natural gas at market prices;

costs associated with perfecting title for mineral rights in some of our properties;

Table of Contents

- continued hostilities in the Middle East and other sustained military campaigns or acts of terrorism or sabotage; and

- other economic, competitive, governmental, legislative, regulatory, geopolitical and technological factors that may negatively impact our businesses, operations or pricing.

Finally, our future results will depend upon various other risks and uncertainties, including, but not limited to, those detailed in "*Risk Factors*." All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by the cautionary statements in this paragraph and elsewhere in this prospectus and speak only as of the date of this prospectus. Other than as required under the securities laws, we do not assume a duty to update these forward-looking statements, whether as a result of new information, subsequent events or circumstances, changes in expectations or otherwise.

Table of Contents

USE OF PROCEEDS

We estimate that our net proceeds from the sale of common stock in this offering will be approximately $ million, assuming an initial public offering price of $ per share (the midpoint of the price range set forth on the cover page of this prospectus) and after deducting estimated expenses and underwriting discounts and commissions of approximately $ million. If the underwriters' over-allotment option is exercised in full, we estimate that our net proceeds will be approximately $ million.

We will not receive any of the proceeds from the sale of shares of our common stock by the selling stockholders. We will pay all of the selling stockholders' expenses related to this offering, other than underwriting discounts and commissions related to the shares sold by the selling stockholders.

We intend to use a portion of the net proceeds from this offering to (i) repay all outstanding indebtedness under our credit facility, which as of October 31, 2011, was approximately $149.1 million; (ii) fund our drilling and development program; and (iii) fund the expansion of our gas processing facilities. We intend to use the following amounts for the above uses:

Use of Proceeds	**Amount (in millions)**
Repayment of credit facility	$
Drilling and development program	
Expansion of processing facilities	
Total	$

Our credit facility matures in September 2016 and bears interest at a variable rate, which was approximately 2.7% per annum as of July 31, 2010. Our outstanding borrowings under our credit facility were incurred to fund exploration, development and other capital expenditures.

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

Affiliates of certain of the underwriters are lenders and agents under our credit facility and, accordingly, will receive a portion of the net proceeds from this offering through the repayment of outstanding borrowings under the credit facility. See "*Underwriters; Conflicts of Interest*."

DIVIDEND POLICY

We do not expect to declare or pay any cash dividends in the foreseeable future on our common stock. Our credit facility currently prohibits us from paying cash dividends on our common stock, and we may enter into debt arrangements in the future that also prohibit or restrict our ability to declare or pay cash dividends on our common stock.

Table of Contents

CAPITALIZATION

The following table sets forth our capitalization, as of September 30, 2011:

- on an actual historical basis;
- on an as adjusted basis to give effect to this offering and the application of the net proceeds as described in "*Use of Proceeds*."

You should read the following table in conjunction with "*Use of Proceeds*," "*Selected Historical Consolidated and Unaudited Pro Forma Financial Data*," "*Management's Discussion and Analysis of Financial Condition and Results of Operations*" and our historical financial statements and unaudited pro forma financial information and related notes thereto appearing elsewhere in this prospectus.

	As of September 30, 2011	
	Actual	**As Adjusted**
	(in thousands)	
Cash and cash equivalents(1)	$ 153	
Long-term debt:		
Credit facility(2)	$ 132,100	
Total long-term debt	132,100	
Stockholders' equity:		
Common stock Class A, $0.001 par value; 99,990,000 shares authorized, 29,122,521 shares issued and outstanding	29	
Common stock Class B, $0.001 par value; 10,000 shares authorized, 6,600 shares issued and outstanding(3)		
Common stock, $0.001 par value; shares authorized; shares issued and outstanding		
Additional paid-in capital	356,582	
Retained earnings	12,706	
Total stockholders' equity	369,317	
Total capitalization	$ 501,417	

(1) As of October 31, 2011, our cash and cash equivalents were $5.1 million.

(2) As of October 31, 2011, there was $149.1 million outstanding under our credit facility.

(3) Following the resignation of Steve Black, 6,000 shares were issued and outstanding. In connection with his employment with us, James R. Casperson, our Chief Financial Officer, has been granted 600 shares of our Class B Common Stock.

Table of Contents

DILUTION

Purchasers of the common stock in this offering will experience immediate and substantial dilution in the net tangible book value per share of the common stock for accounting purposes. Our net tangible book value as of March 31, 2011 was approximately $ million, or $ per share of common stock. Pro forma net tangible book value per share is determined by dividing our pro forma tangible net worth (tangible assets less total liabilities) by the total number of outstanding shares of common stock that will be outstanding immediately prior to the closing of this offering including giving effect to the issuance of restricted stock awards at the closing of this offering. After giving effect to the sale of the shares in this offering and further assuming the receipt of the estimated net proceeds (after deducting underwriting discounts and anticipated expenses of this offering), our adjusted pro forma net tangible book value as of , 2011 would have been approximately $ million, or $ per share. This represents an immediate increase in the net tangible book value of $ per share to our existing stockholders and an immediate dilution (*i.e.*, the difference between the offering price and the adjusted pro forma net tangible book value after this offering) to new investors purchasing shares in this offering of $ per share. The following table illustrates the per share dilution to new investors purchasing shares in this offering:

Assumed initial public offering price per share (the midpoint of the price range set forth on the cover page of this prospectus)	$
Pro forma net tangible book value per share as of September 30, 2011	$
Increase per share attributable to new investors in this offering	$
As adjusted pro forma net tangible book value per share after giving effect to this offering	$
Dilution in pro forma net tangible book value per share to new investors in this offering	$

The following table summarizes, on an adjusted pro forma basis as of , 2011, the total number of shares of common stock owned by existing stockholders and to be owned by new investors, the total consideration paid, and the average price per share paid by our existing stockholders and to be paid by new investors in this offering at $, calculated before deduction of estimated underwriting discounts and commissions:

	Shares Acquired		Total Consideration		Average Price
	Number	**Percent**	**Amount**	**Percent**	**per Share**
Existing stockholders		%	$	%	$ %
New investors					
Total		%	$	%	$ %

Table of Contents

SELECTED HISTORICAL CONSOLIDATED AND UNAUDITED PRO FORMA FINANCIAL DATA

The following tables set forth selected historical financial data of us and our predecessor, BCEC, as of and for the periods indicated. The consolidated statement of operations data for the years ended December 31, 2008, 2009 and the period ended December 23, 2010 are derived from the audited consolidated financial statements of BCEC included elsewhere in this prospectus. The consolidated statements of operations data for December 31, 2006 and 2007 is derived from audited consolidated financial statements of BCEC not included in this prospectus. The consolidated balance sheet data as of December 31, 2006, 2007 and 2008 are derived from the audited consolidated financial statements of BCEC, which are not included in this prospectus. The consolidated balance sheet data as of December 31, 2009 is derived from the audited consolidated financial statements of BCEC included elsewhere in this prospectus. The consolidated balance sheet data as of December 31, 2010 is derived from our audited consolidated financial statements included elsewhere in this prospectus. The consolidated statement of operations data for the period from inception (December 23, 2010) to December 31, 2010 and the nine months ended September 30, 2010 are derived from the financial statements of BCEC appearing elsewhere in this prospectus, and the consolidated statement of operations data for the nine months ended September 30, 2011 and the consolidated balance sheet data as of September 30, 2011 are derived from our unaudited financial statements appearing elsewhere in this prospectus, which, in management's opinion, include all adjustments necessary for the fair presentation of our financial condition as of such date and our results of operations for such periods.

The summary unaudited pro forma statement of operations of Bonanza Creek Energy, Inc. for the year ended December 31, 2010 gives effect to our Corporate Restructuring as if it had occurred on January 1, 2010. The summary unaudited balance sheet of Bonanza Creek Energy, Inc. as of September 30, 2011 gives effect to this offering and the repayment of indebtedness as if they had occurred on September 30, 2011.

Table of Contents

The selected historical financial data should be read in conjunction with "*Management's Discussion and Analysis of Financial Condition and Results of Operations*" and both our and our predecessor's financial statements and the notes to those financial statements included elsewhere in this prospectus.

	Bonanza Creek Energy Company, LLC (Predecessor)						Bonanza Creek Energy, Inc.		Bonanza Creek Energy, Inc. Pro Forma[3]
	Inception to December 31, 2006[1]	2007	2008	2009	Period Ended December 23, 2010[2]	Nine Months Ended September 30, 2010	Period from Inception (December 23, 2010) to December 31, 2010	Nine Months Ended September 30, 2011	Year Ended December 31, 2010
						(unaudited)		(unaudited)	(unaudited)
	(in thousands, except per share data)								
Statement of Operations Data:									
Revenues:									
Oil sales	$ 4,142	$ 11,427	$ 39,967	$ 27,601	$ 34,431	$ 24,412	$ 1,325	$ 57,177	$ 45,413
Natural gas sales	1,113	1,736	5,165	3,671	6,226	4,807	207	9,283	10,253
Natural gas liquids and CO_2 sales	391	821	2,782	3,169	7,672	5,469	213	9,076	8,365
Total revenues	$ 5,646	$ 13,984	$ 47,914	$ 34,441	$ 48,329	$ 34,688	$ 1,745	$ 75,536	$ 64,031
Operating expenses:									
Lease operating	1,584	4,037	20,434	13,449	14,792	10,581	483	14,461	17,285
Severance and ad valorem taxes	325	577	1,847	2,148	1,621	1,055	70	3,860	2,524
Depreciation, depletion and amortization	1,796	4,237	25,463	14,108	14,225	11,554	506	21,083	20,917
General and administrative	2,096	4,752	7,477	7,610	8,375	6,289	323	9,116	9,338
Employee stock compensation[4]									
Exploration	40	65	25	131	361	202		573	380
Impairment of oil and gas properties[5]			26,437	579				4,067	
Cancelled private placement[6]					2,378	2,378			2,378
Total operating expenses	$ 5,841	$ 13,668	$ 81,683	$ 38,025	$ 41,752	$ 32,059	$ 1,382	$ 53,160	$ 52,822
Income (loss) from operations	(195)	316	(33,769)	(3,584)	6,577	2,629	363	22,376	11,209
Other income (expense):									
Interest expense	(2,483)	(5,748)	(12,870)	(16,582)	(18,001)	(13,494)	(58)	(2,687)	(1,263)
Amortization of debt discount		(1,684)	(5,987)	(7,963)	(8,862)	(6,556)			
Write off of deferred financing costs					(1,663)	(1,663)			(1,663)
Gain on sale of oil and gas properties	1,000		8	303	4,055	4,055			4,055
Unrealized gain (loss) in fair value of warrant put option[7]		(32,302)	70,972	(80,640)	34,345	23,672			

Unrealized gain (loss) in fair value of commodity derivatives	356	(925)	48,716	(34,589)	(7,605)	(2,523)	(514)	7,096	(8,119)
Realized gain (loss) on settled commodity derivatives		26	1,913	13,451	5,919	4,897	(47)	(2,353)	5,872
Other income (loss)	11	(43)	(229)	(179)	19	125		(100)	(47)
Total other income (expense)	(1,116)	(40,676)	102,523	(126,199)	8,207	8,513	(619)	1,956	(1,165)
Income (loss) before income taxes	(1,311)	(40,360)	68,754	(129,783)	14,784	11,142	(256)	24,332	10,044
Income tax benefit (expense)(8)							94	(11,464)	(3,696)
Net income (loss)	$ (1,311)	$ (40,360)	$ 68,754	$ (129,783)	$ 14,784	$ 11,142	$ (162)	$ 12,868	$ 6,348
Net income (loss) per common share(9)									
Basic							$ (0.01)	$ 0.44	
Diluted							$ (0.01)	$ 0.44	
Weighted average shares outstanding									
Basic							29,123	29,123	
Diluted							29,123	29,123	

(1) Our predecessor, BCEC, was formed on May 17, 2006.

(2) We completed our Corporate Restructuring on December 23, 2010.

Table of Contents

(3)
The pro forma information above gives effect to our Corporate Restructuring as if it had occurred on January 1, 2010.

(4)
We will recognize employee stock-based compensation expense immediately prior to the consummation of this offering. We also expect to have stock-based compensation expense for future awards. See "*Management's Discussion and Analysis of Financial Condition and Results of Operations Selected Factors and Trends Affecting Our Results of Operations Stock-based Employee Compensation Expenses.*"

(5)
The impairment for the year ended 2008 resulted from a write-down of the carrying value of our oil and natural gas reserves due to depressed year-end oil and natural gas prices.

(6)
Expenditures in connection with a cancelled private placement of our preferred stock.

(7)
In connection with its purchase of our senior subordinated notes D.E. Shaw Synoptic Portfolios 5, L.L.C. received warrants to purchase equity interests in our predecessor. These warrants contained a put right exercisable beginning on May 17, 2014. The periods presented for our predecessor reflect the changes in the fair market value of that put option. The warrants and aggregate warrant exercise price were exchanged for shares of our common stock in connection with our Corporate Restructuring.

(8)
Our predecessor, BCEC, was a partnership for federal income tax purposes and, therefore, was not subject to entity-level taxation. Our pro forma results reflect our taxation as a subchapter "C" corporation at an estimated combined state and federal income tax rate of 36.8%.

(9)
As a limited liability company, ownership interests in our predecessor were held as units rather than shares.

	Bonanza Creek Energy Company, LLC (Predecessor)				**Bonanza Creek Energy, Inc.**		
	Inception to December 31, 2006[1]	**As of December 31, 2007**	**2008**	**2009**	**As of December 31, 2010**	**As of September 30, 2011 (unaudited)**	**As of September 30, 2011 As Adjusted[2] (unaudited)**
			(in thousands)				
Balance Sheet Data:							
Cash and cash equivalents	$ 5,039	$	$ 4,088	$ 2,522	$	$ 153	
Property and equipment, net	52,103	89,646	195,280	188,367	496,582	596,454	
Total assets	62,317	97,044	241,625	211,552	516,104	626,903	
Long term debt, including current portion:							
Credit facility		27,274	107,000	99,000	55,400	132,100	
Senior subordinated notes, net of discount	39,447	51,561	75,499	92,442			
Second lien term loan[3]							
Subordinated unsecured note			10,000	10,799			
Warrant put options[4]	8,839	42,851	828	81,468			
Total members'/stockholders' equity (deficit)	6,794	(33,566)	35,988	(93,795)	356,380	369,318	

	Bonanza Creek Energy Company, LLC (Predecessor)					**Bonanza Creek Energy, Inc.**	
	Inception to December 31, 2006[1]	**Year Ended December 31, 2007**	**2008**	**2009**	**Period Ended December 23, 2010[5]**	**Nine Months Ended September 30, 2010 (unaudited)**	**Period from Inception (December 23, 2010) to December 31, 2010**	**Nine Months Ended September 30, 2011 (unaudited)**

	(in thousands)							
Other Financial Data:								
Net cash provided by (used in) operating activities	$ 3,764	$ (561)	$ 11,128	$ 11,134	$ 22,759	$ 14,141	$ (1,633)	$ 37,333
Net cash provided by (used in) investing activities	(21,739)	(43,265)	(79,581)	(7,185)	(32,127)	(17,265)	(817)	(110,852)
Net cash provided by (used in) financing activities	23,014	38,787	72,541	(5,515)	9,297	(2,857)		73,671
Adjusted EBITDAX(6)	1,653	4,537	14,435	19,067	25,071	18,414	822	45,646

(1) Our predecessor, BCEC, was formed on May 17, 2006.

(2) As adjusted for this offering and the application of proceeds as described in "*Use of Proceeds*."

(3) Our $30 million second lien term loan was fully funded on May 7, 2010 and repaid in full in connection with our Corporate Restructuring.

(4) The warrants and aggregate warrant exercise price were exchanged for shares of our common stock in connection with our Corporate Restructuring.

(5) We completed our Corporate Restructuring on December 23, 2010.

(6) Adjusted EBITDAX is a non-GAAP financial measure. For a definition of Adjusted EBITDAX and a reconciliation of Adjusted EBITDAX to our net income (loss) and net cash provided by (used in) operating activities, see "*Summary Reserve and Operations Data Non-GAAP Financial Measures and Reconciliation Adjusted EBITDAX*" above.

Table of Contents

UNAUDITED PRO FORMA FINANCIAL INFORMATION

We were formed on December 23, 2010, in connection with our Corporate Restructuring. The following unaudited pro forma financial information shows the pro forma effect of our Corporate Restructuring. We have not included a pro forma balance sheet since the effects of our Corporate Restructuring are reflected in the December 31, 2010 balance sheet included elsewhere in this prospectus. The unaudited pro forma statement of operations for the year ended December 31, 2010 was prepared as if our Corporate Restructuring had occurred at January 1, 2010.

The accompanying financial information was from the historical accounting records. We made no additional pro forma adjustment to general and administrative expense since we were the operator of these properties prior to the acquisitions.

The following unaudited pro forma financial statements do not purport to represent what our actual results of operations would have been if this acquisition had occurred on January 1, 2010. The unaudited pro forma financial statements should be read in conjunction with our historical financial statements and related notes for the periods presented included elsewhere in this prospectus.

Table of Contents

	Bonanza Creek Energy Company, LLC Period Ended December 23, 2010	Holmes Eastern Company, LLC Period Ended December 23, 2010	Bonanza Creek Energy, Inc. Period from Inception (December 23, 2010) to December 31, 2010	Pro Forma Adjustments (unaudited)	Bonanza Creek Energy, Inc. Year Ended December 31, 2010 (unaudited)
	(in thousands, except per share data)				
Revenues:					
Oil, natural gas, natural gas liquids and CO_2 sales	$ 48,328	$ 13,958	$ 1,745	$	$ 64,031
Operating expenses:					
Lease operating	14,792	2,010	483		17,285
Severance and ad valorem taxes	1,620	834	71		2,525
Exploration	361	19			380
Depreciation, depletion and amortization(1)	14,225	3,006	506	3,180	20,917
General and administrative	8,375	640	323		9,338
Cancelled private placement	2,378				2,378
Total operating expenses	41,751	6,509	1,383	3,180	52,822
Income from operations	6,577	7,449	362	3,180	11,209
Other income (expense):					
Gain on sale of oil and gas properties	4,055				4,055
Other income (loss)	19	(65)			(47)
Write off of deferred financing costs	(1,663)				(1,663)
Unrealized gain on fair value of warrant put option(2)	34,345			(34,345)	
Amortization of debt discount(3)	(8,862)			8,862	
Realized gain on settled commodity derivatives	5,919		(47)		5,872
Unrealized loss in fair value of commodity derivatives	(7,605)		(514)		(8,119)
Interest expense(4)	(18,001)	(439)	(57)	17,234	(1,263)
Total other income (expense)	8,207	(504)	(618)	(8,249)	(1,165)
Income (loss) before income taxes	$ 14,784	$ 6,945	$ (256)	$ (11,429)	$ 10,044
Pro forma income tax expense(5)					(3,696)

Net Income	$	6,348
Earnings per shares basic and diluted	$	0.22

(1) Pro forma depletion expense gives effect to our Corporate Restructuring which required the application of purchase accounting. The expense was calculated using estimated proved reserves as of the beginning of the period, production for the applicable period, and the fair value of the purchase price allocated to proved oil and gas properties.

(2) BCEC issued an aggregate of 33,089 warrants to purchase Class A units during 2006, 2007, and 2008 in connection with the sale of senior subordinated notes. These warrants included a one time right and option to put the warrants back to BCEC at fair market value less the exercise price. This pro forma adjustment reverses the mark-to-market income for the warrant put right that was recorded during 2010. This

Table of Contents

presentation assumes that the warrants were exercised on January 1, 2010 in connection with a recapitalization.

(3) During 2010, BCEC recorded accretion expense for the subordinated debt discount. This pro forma adjustment reverses the accretion expense recorded during 2010. This presentation assumes that the subordinated debt was paid off on January 1, 2010 in connection with a recapitalization.

(4) This pro forma adjustment reduces interest expense by $10.9 million for BCEC interest expense that was paid in kind during 2010, a further reduction to interest expense for the amortization of debt issuance costs related to BCEC's second lien term loan that was entered into during 2010, and a further reduction for cash interest expense paid on the revolving credit facilities of BCEC and HEC and BCEC's related party note payable during 2010. This presentation assumes that BCEC's subordinated debt, the second lien term loan and BCEC's related party note payable were paid off and the balance outstanding on our revolving credit facility was reduced on January 1, 2010 in connection with a recapitalization.

(5) Pro forma income taxes related to our pre-tax income for the year ended December 31, 2010 and is based on our expected tax rate of 36.8%.

Pro Forma Reserve Quantity and Standardized Measure Information

The following table sets forth certain unaudited pro forma information concerning our proved oil and gas reserves giving effect to our Corporate Restructuring as if it had occurred on January 1, 2010. The following estimates of proved oil and gas reserves, both developed and undeveloped, represent interests we acquired in our Corporate Restructuring, and are located solely within the United States. Proved reserves represent estimated quantities of crude oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed oil and gas reserves are the quantities expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells for which relatively major expenditures are required for completion.

The estimate of proved reserves and related valuations for the period ended December 23, 2010 was based upon a report prepared by Cawley, Gillespie & Associates, Inc. Petroleum Consultants as of December 31, 2010, adjusted for eight days of operations. The estimates of proved reserves are inherently imprecise and are continually subject to revision based on production history, results of additional exploration and development, price changes and other factors. These estimates do not include probable or possible reserves. The information provided does not represent our estimate of expected future cash flows or value of proved oil and gas reserves.

Table of Contents

Changes in estimated reserve quantities:

	Oil (MBbl)			Natural Gas (MMcf)		
	Bonanza Creek Energy Company, LLC	Holmes Eastern Company, LLC	Pro Forma Combined	Bonanza Creek Energy Company, LLC	Holmes Eastern Company, LLC	Pro Forma Combined
Balance December 31, 2009	15,270	6,118	21,388	27,610	16,565	44,175
Extensions and discoveries	1,258	50	1,308	2,249	228	2,477
Sales of minerals in place	(559)		(559)			
Production	(595)	(138)	(733)	(1,309)	(781)	(2,090)
Revisions to previous estimates	1,302	(308)	994	12,674	5,690	18,364
Balance December 23, 2010	16,676	5,722	22,398	41,224	21,702	62,926
Proved developed reserves:						
December 31, 2009	4,710	1,292	6,002	7,021	5,346	12,367
December 23, 2010	6,465	1,734	8,199	13,703	6,413	20,116
Proved undeveloped reserves:						
December 31, 2009	10,560	4,826	15,386	20,589	11,219	31,808
December 23, 2010	10,211	3,988	14,199	27,521	15,289	42,810

The following table sets forth unaudited pro forma information concerning the discounted future net cash flows from our proved oil and gas reserves as of December 23, 2010, net of income tax expense, and giving effect to our Corporate Restructuring as if it had occurred on January 1, 2010. Future income tax expenses are calculated by applying appropriate year-end tax rates to future pretax net cash flows relating to proved oil and natural gas reserves. Future income tax expenses give effect to permanent differences, tax credits and loss carryforwards relating to the proved oil and natural gas reserves. Future net cash flows are discounted at a rate of 10% annually to derive the standardized measure of discounted future net cash flows. This calculation procedure does not necessarily result in an estimate of the fair market value or the present value of our oil and natural gas properties.

Standardized measure of discounted future net cash flows from estimated production of proved oil and gas reserves as of December 23, 2010 (in thousands):

	Bonanza Creek Energy Company, LLC	Holmes Eastern Company, LLC	Pro Forma Combined
Future cash flows	$ 1,366,948	$ 528,802	$ 1,895,750
Future production costs	(434,498)	(138,515)	(573,013)
Future development costs	(222,007)	(130,202)	(352,209)
Future income tax expense	(126,005)	(57,242)	(183,247)
Future net cash flows	584,438	202,843	787,281
10% annual discount for estimated timing of cash flows	(299,329)	(113,149)	(412,478)
Standardized measure of discounted future net cash flows	$ 285,109	$ 89,694	$ 374,803

Future cash flows as shown above were reported without consideration for the effects of derivative transactions outstanding at each period end.

Table of Contents

Changes in standardized measure of discounted future net cash flows from proved oil and gas reserves (in thousands):

	Bonanza Creek Energy Company, LLC	Holmes Eastern Company, LLC	Pro Forma Combined
Beginning of period	$ 185,704	$ 58,150	$ 243,854
Sale of oil and gas produced, net of production costs	(31,916)	(11,113)	(43,029)
Net changes in prices and production costs	97,744	42,468	140,212
Extensions, discoveries and improved recoveries	17,405	590	17,995
Development costs incurred	21,615	9,342	30,957
Changes in estimated development cost	(30,350)	(14,006)	(44,356)
Sales of mineral in place	(10,799)		(10,799)
Revisions of previous quantity estimates	65,959	11,833	77,792
Net change in income taxes	(38,932)	(10,019)	(48,951)
Accretion of discount	20,368	7,183	27,551
Changes in production rates and other	(11,689)	(4,734)	(16,423)
End of period	$ 285,109	$ 89,694	$ 374,803

Average wellhead prices inclusive of adjustments for quality and location used in determining future net revenues related to the standardized measure calculation as of December 23, 2010 were calculated using the first-day-of-the-month price for each of the 12 months that made up the reporting period.

	Bonanza Creek Energy Company, LLC	Holmes Eastern Company, LLC
Oil (per Bbl)	$ 74.77	$ 75.33
Gas (per Mcf)	$ 4.72	$ 4.98

Table of Contents

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with the selected historical financial data and the accompanying financial statements and the notes to those financial statements included elsewhere in this prospectus. The following discussion includes forward-looking statements that reflect our future plans, estimates, beliefs and expected performance. Our actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, those discussed below and elsewhere in this prospectus, particularly in "*Risk Factors*" and "*Cautionary Note Regarding Forward-Looking Statements*."

Overview

We are an independent energy company engaged in the acquisition, exploration, development and production of onshore oil and associated liquids-rich natural gas, primarily in southern Arkansas and in the DJ and North Park Basins in the Rocky Mountains. We were incorporated as a Delaware corporation in December 2010 to acquire all of the outstanding membership interests of BCEOC pursuant to our Corporate Restructuring. For more information regarding our Corporate Restructuring, see " *Recent Developments*." Our primary business objective is to increase stockholder value by investing capital in projects that we expect will increase our production, reserves and cash flow through the exploitation and development of our existing properties while maintaining a low cost structure. In addition, we intend to pursue acquisitions of properties that are complementary to our target areas of operation.

Formed in May 2006, BCEC initially focused on exploiting and developing properties located in the DJ and North Park Basins in the Rocky Mountains and certain fields located in the San Joaquin Valley of central California. In 2008, BCEC expanded its operations by acquiring significant acreage and other properties in southern Arkansas. Following our Corporate Restructuring, we have been able to increase our reserves and production through the exploitation and development of our existing property base, together with pursuing opportunistic acquisitions in areas where we have specific operating expertise. We estimate we will spend $162.1 million in 2011 to drill 114 gross (107.0 net) wells, to perform workovers on 37 gross (30.9 net) wells and to make other improvements to our infrastructure, including the construction of an additional gas processing facility. As of October 31, 2011, we had drilled 104 gross (97.8 net) of these wells, including 36 gross (31.5 net) wells in southern Arkansas, 59 gross (59.0 net) vertical wells in the DJ Basin, 4 gross (3.8 net) horizontal Niobrara wells in the DJ Basin, 2 gross (2.0 net) wells in the North Park Basin and 3 gross (1.5 net) wells in California.

Recent Developments

Corporate Restructuring

On December 23, 2010, our predecessor, BCEC was recapitalized as part of our Corporate Restructuring, as a result of which we became the owner of all of the equity in BCEOC and HEC. Our Corporate Restructuring consisted of the following transactions:

- BCEC contributed all of its ownership interest in its wholly owned subsidiary BCEOC to us in exchange for 6,272,851 shares of our Class A common stock.

- In exchange for $265 million in cash, we sold shares of our Class A common stock ("Class A Common Stock") to Black Bear, an entity advised by West Face Capital, and to certain clients of AIMCo.

- The members of HEC contributed all of their outstanding membership interests in HEC to us in exchange for approximately $59 million in cash (including approximately $7.2 million in assumed debt repaid at closing) and 1,683,536 shares of our Class A Common Stock with a value equal to approximately $21 million, for a total purchase price of approximately $80 million, subject to certain adjustments.

Cash proceeds of approximately $182 million were used to retire BCEC's second lien term loan, senior subordinated notes, a related-party note payable and to reduce the outstanding principal balance under BCEC's credit facility by $29 million.

On April 1, 2011, BCEC was dissolved and the exchange of BCEC's equity for ownership of shares of our common stock held by BCEC was completed. As part of the liquidation of BCEC, (i) shares of our common stock were contributed by certain members of BCEC to Bonanza Creek Employee Holdings, LLC ("BCEH") and (ii) other shares of our common stock were redeemed into an investment trust for the benefit of Bonanza Creek Oil Company, LLC, certain of its members and certain of our employees. We assumed the remaining balance outstanding of approximately $55.4 million under the credit facility, which was repaid on March 29, 2011, from the proceeds of our credit facility.

The acquisition of HEC provided us with additional acreage and working interests in the DJ Basin in the Rocky Mountains and the Dorcheat Macedonia field in southern Arkansas. We believe the properties we acquired are synergistic to our operations. BCEC has operated the interests acquired since May 2009, which consist of acreage adjacent to our producing property base in southern Arkansas and the Rocky Mountains and additional working interests in our existing property base. The properties have associated net proved reserves of approximately 9,339 MBoe at December 23, 2010, of which 30% was developed.

New Senior Credit Agreement

On March 29, 2011, we entered into a four-year $300 million credit agreement with a syndicate of banks providing for a senior secured revolving credit facility with an initial borrowing base of $130 million and with a $5 million subfacility for standby letters of credit. On September 15, 2011, the borrowing base was increased to $180 million with a $15 million subfacility for standby letters of credit. On November 23, 2011, the lenders agreed to increase the borrowing base to $220 million, effective upon execution of the final agreements. For a description of the material terms of our credit facility see *"Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Credit facility."*

Capital Expenditures

We intend to accelerate our production growth by further exploiting our existing proved reserve base in the Mid-Continent and proved and unproved reserves in the Rocky Mountains, including the properties we acquired as a result of the HEC acquisition. In addition, we expect to begin development of our extensive inventory of horizontal Niobrara oil shale potential located in Colorado.

Our total 2011 capital expenditure budget is approximately $162.1 million, exclusive of acquisitions, which consists of:

$141.3 million for development of our oil and gas properties; and

$20.8 million for the construction of an additional gas processing facility that was completed in September 2011 and for other miscellaneous capital expenditures.

We expect to drill 114 gross (107.0 net) wells in 2011, including 42 gross (36.9 net) infill PUD locations in southern Arkansas, 63 gross (62.8 net) wells in the DJ Basin, 4 gross (3.8 net) horizontal Niobrara oil shale wells in the DJ Basin, 2 gross (2.0 net) wells in the North Park Basin, and 3 gross (1.5 net) wells in California. As of October 31, 2011, we had drilled 104 gross (97.8 net) of these wells, including 36 gross (31.5 net) wells in southern Arkansas, 59 gross (59.0 net) vertical wells in the DJ Basin, 4 gross (3.8 net) horizontal Niobrara wells in the DJ Basin, 2 gross (2.0 net) wells in the North Park Basin and 3 gross (1.5 net) wells in California. While we estimate we will spend $141.3 million for the development of our oil and gas properties, the ultimate amount of capital we will spend during the remainder of 2011 depends on the success of our drilling results as the year progresses. To date, our 2011 capital budget has been funded from the proceeds of our Corporate Restructuring, borrowings under our credit facility and cash flow from operations.

To continue uninterrupted development of our oil and natural gas reserves in the Dorcheat Macedonia field, we spent $17.7 million to build a 12.5 MMcf/d processing facility in our Dorcheat Macedonia field. Construction was completed in September of this year. The construction of this new facility is in conjunction with our continued development of the field. Together with our McKamie facility, the facilities process all of the natural gas that we produce from the Dorcheat Macedonia and McKamie Patton fields.

We believe the net proceeds from this offering together with cash flows from operations and additional borrowings under our credit facility will be sufficient to fund the remainder of our 2011 budgeted capital expenditures. When we deem appropriate, we enter into certain derivative arrangements with respect to portions of our oil and natural gas production to allow us to achieve a more predictable cash flow and to reduce some of our exposure to commodity price fluctuations.

Selected Factors and Trends Affecting Our Results of Operations

Revenues. Our revenues depend substantially upon oil and natural gas prices and demand for oil and natural gas. From January 1, 2008 through September 30, 2011, the WTI spot prices for crude oil ranged from a low of $39.40 per barrel to a high of $134.60 per barrel. Oil prices have increased significantly since the first six months of 2010. Our average unhedged sales price for crude oil for the first six months of 2011 was $93.44 per barrel, compared to $72.02 per barrel for the first six months of 2010, which price increase, along with a 91% increase in crude oil sales volumes, contributed to the 148% increase in our oil revenues in those periods.

Production Trends. Our production levels are heavily influenced by our acquisitions and development drilling, as well as the price of oil. In April 2008, we acquired significant producing properties in southern Arkansas. The full-year effect of production from these properties was the primary reason our sales volumes increased by 23% in 2009 compared with 2008. Our sales volumes increased another 14% in 2010 due primarily to development activities in the southern Arkansas and the Rocky Mountains. Our production levels during the nine months ended September 30, 2011 have increased by 79% compared to the nine months ended September 30, 2010 as a result of the HEC acquisition. To further increase our production, we expect to spend approximately $162.1 million in 2011 to drill 114 gross (107.0 net) wells, to perform workovers on 37 gross (30.9 net) wells and to make other improvements to our infrastructure. Although the amount, timing and allocation of capital expenditures is largely discretionary and within our control, if oil and natural gas prices decline or costs increase significantly, we could defer a significant portion of our budget or expected capital expenditures until later periods to prioritize capital projects that we believe have the highest expected returns and potential to generate near-term cash flows. We routinely monitor and adjust our capital expenditures in response to changes in prices, availability of financing, drilling and acquisition costs, industry conditions, the timing of regulatory approvals, the availability of rigs, success or lack of success in drilling activities, contractual obligations, internally generated cash flows and other factors both within and outside our control.

Production Expenses. Our production expenses consist primarily of lease operating costs and severance and ad valorem taxes and are correlated to our level of production and oil prices. Our lease operating costs decreased by 35% from 2008 to 2009, primarily as a result of the reduction of steam injection in our California thermal properties as the price of oil dropped, which made production at these properties less economic. In response to increased oil prices beginning in July 2009, we resumed steam injection, which has resulted in higher production expenses. Our lease operating costs increased by 13% from 2009 to 2010, primarily as a result of a 14% increase in our sales volume, higher compression rental

Table of Contents

costs in our Dorcheat Macedonia field, higher expenditures for well workovers and increased steam injection expense related to our California thermal properties. Generally, as commodity prices and/or our production levels rise, our severance and ad valorem taxes increase.

General and Administrative Expenses. Our general and administrative expenses increased by $1.1 million, or 14%, from 2009 to 2010, a significant portion of which was attributable to aggregate bonus of $0.5 million received by employees in connection with our Corporate Restructuring. Our general and administrative expenses during the nine months ended September 30, 2011 have increased by 45% compared to the nine months ended September 30, 2010 as a result of the HEC acquisition in December 2010. We expect that the additional compliance and disclosure obligations as a public company will require us to implement additional financial and management controls, reporting systems and procedures and hire additional accounting, finance and legal staff (including potentially as a result of the recent resignation of our chief accounting officer), which will result in an estimated annual cost of $3.5 million. Additionally, we believe our general and administrative expenses will increase as a result of stock-based compensation obligations relating to future awards.

Stock-based Employee Compensation Expenses. We expect 197,867 shares of Class A Common Stock will be distributed to our employees by BCEH prior to or shortly following the consummation of this offering. Assuming a Class A Common Stock fair value of $ per share (the midpoint of the price range set forth on the cover page of this offering), we expect to recognize an employee stock-based compensation expense of approximately $ million as of the date of the grant of those shares. In addition, we have awarded 6,600 shares of Class B Common Stock and intend to distribute the remaining 3,400 shares of Class B Common Stock prior to the consummation of this offering. Assuming a common stock fair value of $ per share (the midpoint of the price range set forth on the cover page of this offering), we expect to recognize employee stock compensation expense relating to these grants during the years ended December 31, 2011, 2012, 2013 and 2014 of approximately $ million, $ million, $ million and $ million, respectively, assuming no forfeitures.

Debt Service Obligations. We intend to use the net proceeds from this offering to repay all outstanding indebtedness under our credit facility, resulting in no debt service obligations other than a commitment fee. As of September 30, 2011, we had approximately $132.1 million outstanding under our credit facility. To the extent we borrow additional amounts under our credit facility to fund our capital expenditures or make acquisitions, our debt service obligations will increase, which may require a substantial portion of our operating cash flow depending on our outstanding borrowings, oil and natural gas prices and results of operations.

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 period indicated are discussed below.

Table of Contents

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

Revenues

	Nine Months Ended September 30,			
	2010	2011	Change	Percent Change
	(In thousands, except percentages)			
Revenues:				
Crude oil sales	$ 24,412	$ 57,177	$ 32,765	134 %
Natural gas sales	4,807	9,283	4,476	93 %
Natural gas liquids sales	4,963	8,828	3,865	78 %
CO_2 sales	506	248	(258)	(51)%
Product revenues	$ 34,688	$ 75,536	$ 40,848	118 %

	Nine Months Ended September 30,			
	2010	2011	Change	Percent Change
Sales volumes:				
Crude oil (MBbls)	342.5	634.4	291.9	85%
Natural gas (MMcf)	969.1	1,822.8	853.7	88%
Natural gas liquids (MBbls)	91.8	128.8	37.0	40%
Crude oil equivalent (MBoe)[1]	595.8	1,067.0	471.2	79%

(1) Determined using the ratio of 6 Mcf of natural gas to 1 Bbl of crude oil. Excludes CO_2 sales.

	Nine Months Ended September 30,			
	2010	2011	Change	Percent Change
Average Sales Prices (before hedging)[1]:				
Crude oil (per Bbl)	$ 71.29	$ 90.13	$ 18.84	26%
Natural gas (per Mcf)	4.96	5.09	0.13	3%
Natural gas liquids (per Bbl)	54.09	68.56	14.47	27%
Crude oil equivalent (per Boe)[2]	57.38	70.57	13.19	23%

	Nine Months Ended September 30,			
	2010	2011	Change	Percent Change
Average Sales Prices (after hedging)[1]:				
Crude oil (per Bbl)	$ 73.34	$ 85.67	$ 12.33	17 %
Natural gas (per Mcf)	5.51	5.36	(0.15)	(3)%
Natural gas liquids (per Bbl)	54.09	68.56	14.47	27 %
Crude oil equivalent (per Boe)[2]	59.45	68.36	8.91	15 %

(1) Although we do not designate our derivatives as cash flow hedges for financial statement purposes, the derivatives do economically hedge the price we receive for crude oil and natural gas.

(2) Determined using the ratio of 6 Mcf of natural gas to 1 Bbl of crude oil. Excludes CO_2 sales.

Revenues increased by 118%, to $75.5 million for the nine months ended September 30, 2011 compared to $34.7 million for the nine months ended September 30, 2010. Oil production increased 85% and natural gas production increased 93% during the nine months ended September 30, 2011 as compared

Table of Contents

to the nine months ended September 30, 2010. The most significant component of the increased production was related to the acquisition of HEC, which occurred on December 23, 2010. Our product revenues and production for the nine months ended September 30, 2010 excluded HEC revenues and production of $10.4 million and 201.1 Mboe, respectively. The increase in net revenues was also the result of a 26% increase in oil prices with a 3% increase in natural gas prices, respectively, for an overall increase of 23% per Boe. Also contributing to the increased revenue was the increased production attributable to our drilling program.

Operating Expenses

	Nine Months Ended September 30,			
	2010	2011	Change	Percent Change
	(In thousands, except percentages)			
Expenses:				
Lease operating	$ 10,581	$ 14,461	$ 3,880	37%
Severance and ad valorem taxes	1,055	3,860	2,805	266%
General and administrative	6,289	9,116	2,827	45%
Depreciation, depletion and amortization	11,554	21,083	9,529	82%
Exploration	202	573	371	184%
Operating expenses	$ 29,681	$ 49,093	$ 19,412	65%

	Nine Months Ended September 30,			
	2010	2011	Change	Percent Change
Selected Costs ($ per Boe):				
Lease operating	$ 17.76	$ 13.55	$ (4.21)	(24)%
Severance and ad valorem taxes	1.77	3.62	1.85	105 %
General and administrative	10.56	8.54	(2.02)	(19)%
Depreciation, depletion and amortization	19.40	19.76	0.36	2 %
Exploration	0.34	0.54	0.20	59 %
Operating expenses	$ 49.83	$ 46.01	$ (3.82)	(8)%

Lease operating expenses. Our lease operating expenses increased $3.9 million, or 37%, to $14.5 million in the first nine months of 2011 from $10.6 million in the first nine months of 2010 and decreased on an equivalent basis from $17.76 per Boe to $13.55 per Boe. The increase in lease operating expense was related to increased production volumes due to the acquisition of HEC on December 23, 2010. The nine months ended September 30, 2010 does not include HEC lease operating expenses, which were $1.5 million. During the nine months ended September 30, 2011, gauging and pumping, well servicing and testing, and compressor rentals were $1.4 million, $1.2 million, and $0.7 million higher, respectively, than the nine months ended September 30, 2010. The decrease in lease operating expenses on an equivalent basis was primarily related to the lower operating costs of the wells acquired from HEC. On an equivalent basis, the lease operating expense for the wells acquired from HEC was $7.39 per Boe during the nine months ended September 30, 2010 as compared to the lease operating expense for BCEC's wells which was $17.76 per Boe during the nine months ended September 30, 2010.

Severance and ad valorem taxes. Our severance and ad valorem taxes increased $2.8 million, or 266%, to $3.9 million in the first nine months of 2011 from $1.1 million in the first nine months of 2010 and increased on a Boe basis from $1.77 to $3.62. The increase was primarily related to a 79% increase in production volumes and a 23% increase in realized prices per Boe during the nine months ended September 30, 2011 as compared to the nine months ended September 30, 2010, and an increase in

Table of Contents

ad valorem tax of $1.3 million due to higher assessment values. The nine months ended September 30, 2010 does not include HEC severance and ad valorem tax, which were $0.6 million. The increase in severance and ad valorem taxes on a Boe basis for the nine months ended September 30, 2011 as compared to the nine months ended September 30, 2010 was primarily related to higher ad valorem taxes of $1.3 million and true-ups of estimated severance taxes based on Colorado severance tax returns for 2009 and 2010 that were filed during April of the subsequent year. The revision of estimated severance taxes based on the final Colorado severance tax returns resulted in a decrease in severance tax expense in 2010 and an increase in severance tax expense in 2011.

General and administrative. Our general and administrative expense increased $2.8 million, or 45%, to $9.1 million in the first nine months of 2011 from $6.3 million in the first nine months of 2010. The nine months ended September 30, 2010 does not include HEC's general and administrative expenses, which were $0.5 million. During the nine month period ended September 30, 2011, wages and benefits, legal and professional services fees, travel and lodging, and business development were $1.3 million, $1.1 million, $0.2 million, and $0.1 million, respectively, higher than the previous period. The increase in wages and benefits is related to increased head count and $0.9 million of increase in legal and professional services fees were related to investigations and transactions not consummated. The decrease in general and administrative expenses on an equivalent basis was primarily related to the acquisition of HEC, which added significant production without adding a commensurate amount of general and administrative expenses.

Depreciation, depletion and amortization. Our depreciation, depletion and amortization expense increased $9.5 million, or 82%, to $21.1 million in the nine months ended September 30, 2011 from $11.6 million in the nine months ended September 30, 2010. This increase was the result of a 79% increase in production and the step up in basis that was recorded in oil and gas properties as a result of our Corporate Restructuring. In connection with our Corporate Restructuring, all of our oil and gas fields were adjusted to fair value based on each field's discounted future net cash flows, which resulted in basis increases to the Mid Continent and Rocky Mountain fields with corresponding decreases to the California fields. Our depreciation, depletion and amortization expense per Boe increased by $0.36, or 2%, to $19.76 for the nine months ended September 30, 2011 as compared to $19.40 for the nine months ended September 30, 2010.

Exploration. Our exploration expense increased $0.4 million, or 184%, to $0.6 million in the nine months ended September 30, 2011 from $0.2 million in the nine months ended September 30, 2010. The increase in exploration expense was primarily related to the acquisition of 7,700 acres of 3-D seismic data on the eastern edge of the Wattenberg field in Weld County, Colorado to help evaluate our Niobrara oil shale acreage.

Impairment of Proved Properties. The Company recorded $3.5 million of proved property impairments on the Company's legacy California assets and $0.6 million of proved property impairment in one non-core field in Southern Arkansas for the nine months ended September 30, 2011. The impairments of the Company's legacy assets in California were related to steam flooding results that were lower than expected and the impairment of the non-core field in Southern Arkansas was related to the loss of a lease. There were no impairments of proved properties for the nine months ended September 30, 2010.

Other Income and Expense

Interest expense. Our interest expense decreased $10.8 million, or 80%, to $2.7 million in the nine months ended September 30, 2011 from $13.5 million in the nine months ended September 30, 2010. The decrease resulted from the application of $182 million of cash proceeds from our Corporate Restructuring to repay the second lien term loan, the senior subordinated notes and a related party note payable, and to repay $29 million of principal under our credit facility on December 23, 2010. Average debt outstanding for the nine months ended September 30, 2011 was $81.5 million as compared to $209.4 million for the nine months ended September 30, 2010.

Gain on sale of oil and gas properties. Our gain on sale of oil and gas properties decreased $4.1 million to no gain in the nine months ended September 30, 2011 from $4.1 million in the nine months ended September 30, 2010. In March 2010, we sold our non-operated working interest in the Jasmin, California property resulting in a gain on sale of $ 4.1 million.

Realized gain (loss) on settled commodity derivatives. Realized gains on oil and gas hedging activities decreased by $7.3 million from a gain of $4.9 million for the nine months ended September 30, 2010 to a loss of $2.4 million for the nine months ended September 30, 2011. Because we assumed a derivative in a liability position in 2008, our realized gain was higher by $3.7 million upon the settlement of this portion of the assumed derivative in the nine months ended September 30, 2010. The decrease from a realized cash hedge gain to a loss period over period was primarily related to commodity prices that were 23% higher during the nine months ended September 30, 2011 as compared to the nine months ended September 30, 2010.

Income Tax Expense. Our predecessor, BCEC, was not subject to federal and state income taxes. As a result of our Corporate Restructuring, we were organized as a Delaware corporation subject to federal and state income taxes. During the nine months ended September 30, 2011, the estimated effective tax rate was revised to reflect significant capital expenditures in Arkansas during 2011 that increased the effective tax rate from 36.87% to 38.04%. The higher effective tax rate was applied to the January 1, 2011 deferred income tax liability increasing the net deferred tax liability and deferred income tax expense by $2.2 million for the nine months ended September 30, 2011, which resulted in a total deferred income tax expense in our consolidated statement of operations of $11.5 million. We are allowed to deduct various items for tax reporting purposes that are capitalized for purposes of financial statement presentation. All income taxes for the period ended September 30, 2011 were deferred.

Change in fair value of warrant put option. The fair value of the warrant put option decreased $23.7 million, or 100%, to $0 for the nine months ended September 30, 2011 from a gain of $23.7 million for the nine months ended September 30, 2010. The decrease resulted from the exercise of the warrants on December 23, 2010 in connection with our Corporate Restructuring.

Amortization of debt discount. Our expense for amortization of debt discount decreased $6.6 million, or 100%, to $0 for the nine months ended September 30, 2011 from $6.6 million for the nine months ended September 30, 2010. The decrease resulted from the retirement of BCEC's senior subordinated notes on December 23, 2010 in connection with our Corporate Restructuring.

Eight Day Period Ended December 31, 2010

We completed our Corporate Restructuring on December 23, 2010. The operating results of BCEI for the eight-day period from December 24, 2010 through December 31, 2010 were net revenues, operating expenses, and income from operations of approximately $1.7 million, $1.4 million, and $0.4 million, respectively, and did not include transactions that were inconsistent or unusual when compared to the results for the audited period ended December 23, 2010. Other expense during this period was primarily comprised of a $0.5 million unrealized loss in the fair value of commodity derivatives.

Period Ended December 23, 2010 Compared to Year Ended December 31, 2009

We completed our Corporate Restructuring on December 23, 2010. The operating results presented below for the audited period ended December 23, 2010 exclude the audited eight-day period from December 24, 2010 through December 31, 2010.

Table of Contents

Revenues

	Year Ended December 31, 2009	Period Ended December 23, 2010	Change	Percent Change
	(In thousands, except percentages)			
Revenues:				
Crude oil sales	$ 27,601	$ 34,431	$ 6,830	25%
Natural gas sales	3,671	6,226	2,555	70%
Natural gas liquids sales	2,886	7,088	4,202	146%
CO_2 sales	283	583	300	106%
Product revenues	$ 34,441	$ 48,328	$ 13,887	40%

	Year Ended December 31, 2009	Period Ended December 23, 2010	Change	Percent Change
Sales Volumes:				
Crude oil (MBbls)	507.4	469.0	(38.4)	(8)%
Natural gas (MMcf)	939.0	1,308.5	369.5	39 %
Natural gas liquids (MBbls)	69.1	126.5	57.4	83 %
Crude oil equivalent (MBoe)(1)	733.0	813.6	80.6	11 %

(1) Determined using the ratio of 6 Mcf of natural gas to 1 Bbl of crude oil. Excludes CO_2 sales.

	Year Ended December 31, 2009	Period Ended December 23, 2010	Change	Percent Change
Average Sales Prices (before hedging)[1]:				
Crude oil (per Bbl)	$ 54.40	$ 73.41	$ 19.01	35%
Natural gas (per Mcf)	3.91	4.76	0.85	22%
Natural gas liquids (per Bbl)	41.77	56.04	14.27	34%
Crude oil equivalent (per Boe)[2]	46.60	58.69	12.09	26%

	Year Ended December 31, 2009	Period Ended December 23, 2010	Change	Percent Change
Average Sales Prices (after hedging)[1]:				
Crude oil (per Bbl)	$ 67.40	$ 75.07	$ 7.67	11%
Natural gas (per Mcf)	5.05	5.01	(0.04)	(1)%
Natural gas liquids (per Bbl)	41.77	56.04	14.27	34%
Crude oil equivalent (per Boe)[2]	57.07	60.05	2.98	5%

(1)

Although we do not designate our derivatives as cash flow hedges for financial statement purposes, the derivatives do economically hedge the price we receive for crude oil and natural gas.

(2) Determined using the ratio of 6 Mcf of natural gas to 1 Bbl of crude oil. Excludes CO_2 sales.

Product revenues increased by 40%, to $48 million in 2010 compared to $34 million in 2009. The increase in product revenues was primarily due to higher average prices for oil, natural gas and natural gas liquids in 2010 as compared to 2009 of 35%, 22% and 34%, respectively, and higher natural gas and

Table of Contents

natural gas liquids production in 2010 as compared to 2009 of 39% and 83%, respectively. Production increases for natural gas and natural gas liquids were due primarily to 2010 development activities on our properties in southern Arkansas and Colorado. During 2010, we drilled 51 net wells as compared to 2.5 net wells drilled in 2009. Furthermore, our McKamie gas plant in Arkansas processed natural gas for HEC in 2009 and 2010 and we recognized natural gas and natural gas liquids volumes and revenues earned under a processing agreement. Natural gas and natural gas liquid volumes and revenues increased as HEC drilled 12 wells in 2010 as compared to 4 wells in 2009. Oil production decreased by 4% in 2010 as compared to 2009 primarily due to low drilling in 2009 and early 2010 resulting in a continued rate of decline for oil production from existing wells, partially offset by increased drilling activity in the later part of 2010.

Operating Expenses

	Year Ended December 31, 2009	Period Ended December 23, 2010	Change	Percent Change
	(In thousands, except percentages)			
Expenses:				
Lease operating	$ 13,449	$ 14,792	$ 1,343	10 %
Severance and ad valorem taxes	2,148	1,620	(528)	(25)%
General and administrative	7,610	8,375	765	10 %
Depreciation, depletion and amortization	14,108	14,225	117	1 %
Exploration	131	361	230	176 %
Impairment of oil and gas properties	579		(579)	(100)%
Cancelled private placement		2,378	2,378	100 %
Operating expenses	$ 38,025	$ 41,751	$ 3,726	10 %

	Year Ended December 31, 2009	Period Ended December 23, 2010	Change	Percent Change
Selected Costs ($ per Boe):				
Lease operating	$ 18.35	$ 18.18	$ (.17)	(1)%
Severance and ad valorem taxes	2.93	1.99	(.94)	(32)%
General and administrative	10.38	10.30	(.08)	%
Depreciation, depletion and amortization	19.25	17.49	(1.76)	(9)%
Exploration	0.18	0.44	0.26	144 %
Impairment of oil and gas properties	0.79		(.79)	(100)%
Cancelled private placement		2.92	2.92	100 %
Operating expenses	$ 51.88	$ 51.32	$ (0.56)	(1)%

Lease operating expenses. Our lease operating expenses increased $1.3 million, or 10%, to $14.8 million in 2010 from $13.4 million in 2009. The increase in lease operating expenses was primarily related to higher compression rental costs in our Dorcheat Macedonia field, increased workover activity and higher steam injection expense related to our California thermal properties.

Severance and ad valorem taxes. Severance and ad valorem taxes per Boe decreased by $0.94, or 32%, to $1.99 for 2010 from $2.93 for 2009. The decrease in production taxes was due primarily to refunds received from Colorado for overpayment of severance taxes in 2008 and 2009.

General and administrative. Our general and administrative expenses increased $0.8 million, or 10%, to $8.4 million for 2010 from $7.6 million for 2009. The increase in general and administrative expenses

Table of Contents

was due primarily to an aggregate bonus of $0.5 million awarded to employees in connection with our Corporate Restructuring in December 2010.

Depreciation, depletion and amortization. Our depreciation, depletion and amortization expense increased $0.1 million, or 1%, to $14.2 million in 2010 from $14.1 million in 2009. Our depreciation, depletion and amortization expense per Boe produced decreased by $1.76, or 9%, to $17.49 for 2010 as compared to $19.25 for 2009 due primarily to additional reserves resulting from higher commodity prices in 2010 and reserves adds from workover and behind-pipe activities.

Other Income and Expense

Interest expense. Our interest expense increased $1.4 million, or 8%, to $18.0 million in 2010 from $16.6 million in 2009. As a result of $30 million in borrowings on a second lien note at a 14% rate, we paid down our first lien revolver at an annual rate of approximately 4%.

Gain on sale of oil and gas properties. Our gain on sale of oil and gas properties increased $3.8 million to $4.1 million in 2010 from $0.3 million in 2009. In March 2010, we sold our non-operated working interest in the Jasmin, California property resulting in a gain on sale of $ 4.1 million.

Realized gain on settled commodity derivatives. Our realized gain on settled commodity derivatives decreased $7.6 million, or 56%, to $5.9 million in 2010 from $13.5 million in 2009. The change was primarily related to higher commodity prices during 2010 that lowered our realized gain.

Cancelled private placement. During 2010, we incurred expenditures of $2.4 million in connection with our efforts to sell preferred stock through a private placement offering. Cost incurred is comprised primarily of legal fees, printing cost, travel and audit fees. The offering was cancelled in August 2010.

Change in fair value of warrant put option. The unrealized gain from the change in the fair value of the warrant put option increased $115 million to a gain of $34.3 million for 2010, as compared to a $80.6 million loss for the period ended December 31. 2009. This gain of $34.3 million resulted from a decrease in the value of the warrant put option from $81.5 million as of December 31, 2009 to $47.1 million as of December 23, 2010. The warrant was exercised for Class A units of BCEC and subsequently redeemed for shares of our Class A Common Stock in connection with our Corporate Restructuring and, therefore, no exercise occurred after December 23, 2010.

Accretion of debt discount. Our expense for accretion of debt discount increased $0.9 million, or 11%, to $8.9 million for the year ended December 31, 2010. The accretion expense is related to the amortization of our debt discount for the Series A, Series B and Series C Senior Subordinated Unsecured Notes.

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

Revenues

	Year Ended December 31,			
	2008	2009	Change	Percent Change
	(In thousands, except percentages)			
Revenues:				
Crude oil sales	$ 39,967	$ 27,601	$ (12,366)	(31)%
Natural gas sales	5,165	3,671	(1,494)	(29)%
Natural gas liquids sales	2,038	2,886	848	42%
CO_2 sales	744	283	(461)	(62)%
Product revenues	$ 47,914	$ 34,441	$ (13,473)	(28)%

Table of Contents

	Year Ended December 31,			
	2008	2009	Change	Percent Change
Sales Volumes:				
Crude oil (MBbls)	453.7	507.4	53.7	12%
Natural gas (MMcf)	668.9	939.0	270.1	40%
Natural gas liquids (MBbls)	35.5	69.1	33.6	95%
Crude oil equivalent (MBoe)(1)	600.7	733.0	132.3	22%

(1) Determined using the ratio of 6 Mcf of natural gas to 1 Bbl of crude oil. Excludes CO_2 sales.

	Year Ended December 31,			
	2008	2009	Change	Percent Change
Average Sales Prices (before hedging)(1):				
Crude oil (per Bbl)	$ 88.09	$ 54.40	$ (33.69)	(38)%
Natural gas (per Mcf)	7.72	3.91	(3.81)	(49)%
Natural gas liquids (per Bbl)	57.45	41.77	(15.68)	(27)%
Crude oil equivalent (per Boe)(2)	78.53	46.60	(31.93)	(41)%

	Year Ended December 31,			
	2008	2009	Change	Percent Change
Average Sales Prices (after hedging)(1):				
Crude oil (per Bbl)	$ 79.59	$ 67.40	$ (12.19)	(15)%
Natural gas (per Mcf)	7.93	5.05	(2.88)	(36)%
Natural gas liquids (per Bbl)	57.45	41.77	(15.68)	(27)%
Crude oil equivalent (per Boe)(2)	72.35	57.07	(15.28)	(21)%

(1) Although we do not designate our derivatives as cash flow hedges for financial statement purposes, the derivatives do economically hedge the price we receive for crude oil and natural gas.

(2) Determined using the ratio of 6 Mcf of natural gas to 1 Bbl of crude oil. Excludes CO_2 sales.

Revenues decreased by 28%, to $34 million, in 2009 compared to $48 million in 2008. The decrease in net revenues was primarily due to significantly lower average oil and natural gas prices in 2009. The 42% increase in natural gas liquids revenues was the result of increased volumes of natural gas liquids as a result of our acquisition of producing properties in southern Arkansas in April 2008. For 2009, sales volumes increased approximately 23% compared to 2008. The increase in sales volumes was primarily due to our acquisition of producing properties in southern Arkansas in April 2008 and the increase in drilling activity subsequent to the acquisition.

Table of Contents

Operating Expenses

	Year Ended December 31,			
	2008	2009	Change	Percent Change
	(In thousands, except percentages)			
Expenses:				
Lease operating	$ 20,435	$ 13,449	$ (6,986)	(34)%
Severance and ad valorem taxes	1,847	2,148	301	16 %
General and administrative	7,477	7,610	133	2 %
Depreciation, depletion and amortization	25,463	14,108	(11,355)	(45)%
Exploration	25	131	106	424 %
Impairment of oil and gas properties	26,437	579	(25,858)	(98)%
Operating expenses	$ 81,684	$ 38,025	$ (43,659)	(53)%

	Year Ended December 31,			
	2008	2009	Change	Percent Change
Selected Costs ($ per Boe):				
Lease operating	$ 34.02	$ 18.35	$ (15.67)	(46)%
Severance and ad valorem taxes	3.07	2.93	(.14)	(5)%
General and administrative	12.45	10.38	(2.07)	(17)%
Depreciation, depletion and amortization	42.39	19.25	(23.14)	(55)%
Exploration	0.04	0.18	0.14	350 %
Impairment of oil and gas properties	44.01	0.79	(43.22)	(98)%
Operating expenses	$ 135.98	$ 51.88	$ (84.10)	(62)%

Lease operating expense. Our lease operating expenses decreased $7.0 million, or 34%, to $13.4 million in 2009 from $20.4 million in 2008. The decrease in lease operating expenses was primarily related to the reduction of steam injection in our California thermal properties.

Severance and ad valorem taxes. Our severance and ad valorem taxes increased $0.3 million, or 16%, to $2.1 million in 2009 from $1.8 million in 2008. Severance and ad valorem taxes per Boe decreased $0.14, or 5%, to $2.93 for 2009 from $3.07 for 2008.

General and administrative. Our general and administrative expenses increased $0.1 million, or 2%, to $7.6 million for 2010 from $7.5 million for 2009.

Depreciation, depletion and amortization. Our depreciation, depletion and amortization expense decreased $11.4 million, or 45%, to $14.1 million in 2009 from $25.5 million in 2008. Our depreciation, depletion and amortization expense per Boe produced decreased by $23.14, or 55%, to $19.25 for 2009 as compared to $42.39 for 2008. The decrease was primarily due to a $26.4 million impairment we took on certain of our properties and accompanying reserve write-down, as a result of depressed oil and gas prices as of December 31, 2008.

Other Income and Expense

Interest expense. Our interest expense increased $3.7 million, or 29%, to $16.6 million in 2009 from $12.9 million in 2008. The increase was due to increased borrowings resulting primarily from the acquisition of producing properties in southern Arkansas.

Table of Contents

Change in fair value of warrant put option. The unrealized loss from the change in the fair value of the warrant put option increased $151.6 million to a loss of $80.6 million for the year ended December 31, 2009. The unrealized loss resulted from an increase in value of the warrant put option from $0.8 million as of December 31, 2008 to $81.5 million as of December 31, 2009.

Accretion of debt discount. Our expenses for accretion of debt discount increased $2.0 million, or 33%, to $8.0 million for the year ended December 31, 2009. The accretion expense is related to the amortization of our debt discount for the Series A, Series B and Series C Senior Subordinated Unsecured Notes.

Realized gain (loss) on settled commodity derivatives. Our realized gain on settled commodity derivatives increased $11.5 million to $13.5 million for the year ended December 31, 2009. The change was primarily related to lower commodity prices during 2009 that increased our realized gain.

Liquidity and Capital Resources

Our primary sources of liquidity to date have been proceeds from our Corporate Restructuring, capital contributions from investors, borrowings under our credit facility and cash flows from operations. Our primary use of capital has been for the acquisition and development of oil and natural gas properties.

On March 29, 2011, we entered into $300 million senior secured revolving credit facility to provide us with additional liquidity and flexibility for capital expenditures. As of September 30, 2011, we had $132.1 million of indebtedness outstanding and $47.9 million of borrowing capacity available under our credit facility. We intend to use a portion of the proceeds from this offering to pay down all of the debt outstanding under our credit facility. On September 15, 2011, our borrowing base was increased to $180 million. On November 23, 2011, the lenders agreed to increase the borrowing base to $220 million, effective upon execution of the final agreements. The size of our borrowing base is at the discretion of the lenders under our credit facility and is dependent upon a number of factors, including commodity prices and reserve levels. For a summary of the material provisions of our credit facility, see " *Credit facility*."

We expect that in the future our commodity derivative positions will help us stabilize a portion of our expected cash flows from operations despite potential declines in the price of oil and natural gas. Please see " *Quantitative and Qualitative Disclosures on Market Risks.*"

We actively review acquisition opportunities on an ongoing basis. Our ability to make significant additional acquisitions for cash is dependent on our obtaining additional equity or debt financing, which we may not be able to obtain on terms acceptable to us or at all.

	Year Ended December 31,			Nine Months Ended September 30,	
	2008	**2009**	**2010**	**2010**	**2011**
			(in thousands)		
Financial Measures:					
Net cash provided by operating activities	$ 11,128	$ 11,134	$ 21,726	$ 14,141	$ 37,333
Net cash provided by (used in) investing activities	(79,581)	(7,185)	(32,944)	(17,265)	(110,852)
Net cash provided by (used in) financing activities	72,541	(5,515)	9,297	2,857	73,671
Cash and cash equivalents	4,088	2,522		2,255	153
Acquisitions of oil and gas properties	40,846	650	1,066	608	1,383
Exploration and development of oil and gas properties and gas processing facility	38,384	6,612	35,545	24,137	109,970

Table of Contents

Cash flows provided by operating activities

Net cash provided by operating activities was $37.3 million for the nine months ended September 30, 2011, compared to $14.1 million provided by operating activities for the nine months ended September 30, 2010. The increase in operating activities resulted primarily from an increase in revenues, increased production, and increased commodity prices offset by cash utilized in connection with changes in working capital when comparing the periods. Cash utilized by changes in working capital for the nine months ended September 30, 2011 was $5.8 million as compared to $2.3 million that was provided by changes in working capital for the comparable period during 2010. Decreases in working capital of $5.8 million for the nine months ended September 30, 2011 is comprised primarily of increases in accounts receivable of $6.1 million, offset by an increase in accounts payable and accrued expenses of $0.5 million. For the period ended September 30, 2010 the majority of the cash provided by operating activities was derived from an increase in accounts receivable of $2.7 million and an increase in accounts payable and accrued liabilities of $4.7 million.

Net cash provided by operating activities was $21.7 million, $11.1 million and $11.1 million for each of the years ended December 31, 2010, 2009 and 2008, respectively. Cash provided by changes in working capital for the year ended December 31, 2010 was $4.2 million as compared to cash that was utilized by changes in working capital in the amount of $2.8 million for the year ended December 31, 2009. Cash provided by changes in working capital for the year ended December 31, 2008 was $1.8 million. Increases in working capital of $4.2 million during 2010 is due primarily to an increase in trade payables and accrued expenses (exclusive of capital accruals) of $6.6 million, partially offset by an increase in trade receivables of $2.4 million, which changes are related to higher levels of activity in 2010.

Cash flows provided by (used in) investing activities

Expenditures for development of oil and natural gas properties and natural gas plants are the primary use of our capital resources. Net cash used in investing activities for the nine months ended September 30, 2011 was $110.9 million, compared to $17.3 million cash used in investing activities for the nine months ended September 30, 2010. Net cash used for the development of oil and natural gas properties was $110 million including expenditures of $18.1 million for a natural gas plant. For the nine months ended September 30, 2010 expenditures for the development of oil and natural gas properties was $23.2 million offset by proceeds of $7.5 million for sale of our interest in the Jasmin field in California. For the year ended December 31, 2010, excluding our Corporate Restructuring, net cash used in investing activities was $32.9 million, of which we spent approximately $1.1 million on acquisitions, $35.5 million for the exploration and development of oil and gas properties, advanced $3.7 million to fund HEC's exploration and development program, offset by the receipt of proceeds in the amount of $7.5 million for the sale of the Jasmin field. In connection with our Corporate Restructuring, $59 million in cash along with common stock valued at $21.1 million was used to acquire HEC. For the year ended December 31, 2009, net cash used in investing activities was $7.2 million, of which we spent approximately $0.7 million for the acquisition of oil and gas properties and $6.6 million for the exploration and development of oil and gas properties. For the year ended December 31, 2008, net cash used in investing activities was $79.6 million, of which we spent approximately $41 million in cash on the acquisition of properties in southern Arkansas and the remainder on developing our proved reserves.

Cash flows provided by (used in) financing activities

Net cash flow provided by financing activities for the nine months ended September 30, 2011 was $73.7 million primarily related to net borrowings on our line of credit in the amount of $76.7 million offset by deferred financing costs of approximately $3 million. Net cash provided by financing activities for the nine months ended September 30, 2010 was $2.8 million and was primarily related to net borrowings on our revolving line net of payments on subordinated debt and $3.3 million of deferred financing costs. Net cash provided by financing, excluding Corporate Restructuring, was $9.3 million for the year ended

Table of Contents

December 31, 2010, primarily related to net borrowings in the amount of $12.7 million offset by deferred financing charges in the amount of $3.4 million. Net cash used in financing activities was $5.5 million for the year ended December 31, 2009, primarily the result of making debt payments on our credit facility. Net cash provided by financing activities was $72.5 million for the year ended December 31, 2008 was primarily the result of increases in borrowings under our credit facility to fund development activities and issuing subordinated debt to acquire our properties in southern Arkansas.

In connection with our Corporate Restructuring, we received net proceeds of approximately $265 million from the sale of shares of our common stock to Black Bear, an entity advised by West Face Capital, and to certain clients of AIMCo. Proceeds from this transaction in the amount of $59 million along with common stock valued at $21.1 million was used to acquire HEC, $17.3 million of the proceeds were used for debt extinguishment penalties, and $182 million was used to retire the second lien term loan, the senior subordinated notes and a related party note payable, and to make a $29 million line of credit principal payment.

Credit facility

On March 29, 2011, we entered into a credit agreement providing for a $300 million senior secured revolving credit facility with an initial borrowing base of $130 million with a $5 million subfacility for standby letters of credit. On September 15, 2011, our borrowing base was increased to $180 million with a $15 million subfacility for standby letters of credit. On November 23, 2011, the lenders agreed to increase the borrowing base to $220 million, effective upon execution of the final agreements. This credit facility is guaranteed by all of our subsidiaries.

Our borrowing base under the credit agreement is redetermined semiannually on each April 1 and October 1 and may be redetermined up to one additional time between such scheduled determinations upon our request or upon the request of the required lenders (defined as lenders holding $66^2/_3$% of the aggregate commitments). The borrowing base is redetermined (i) in the sole discretion of the administrative agent and all of the lenders, (ii) in accordance with their customary internal standards and practices for valuing and redetermining the value of oil and gas properties in connection with reserve based oil and natural gas loan transactions, (iii) in conjunction with the most recent engineering report and other information received by the administrative agent and the lenders relating to our proved reserves and (iv) based upon the estimated value of our proved reserves as determined by the administrative agent and the lenders.

We intend to use the net proceeds from this offering to repay all outstanding indebtedness under our credit facility, leaving us approximately $220 million available for future borrowings. As of October 31, 2011, we had approximately $149.1 million outstanding under our credit facility. The credit facility matures on September 15, 2016. Amounts borrowed and repaid under the credit facility may be reborrowed. The credit facility may be used only to finance development of oil and gas properties, for working capital and for other general corporate purposes.

Our obligations under the credit facility are secured by first priority liens on all of our property and assets (whether real, personal, or mixed, tangible or intangible), including our proved reserves and our oil and gas properties (which term is defined to include fee mineral interests, term mineral interests, leases, subleases, farm-outs, royalties, overriding royalties, net profit interests, carried interests, production payments, back in interests and reversionary interests). The facility is guaranteed by us and all of our direct and indirect subsidiaries.

Interest under the credit facility is generally determined by reference to either, at our option:

- the London interbank offered rate, or LIBOR, for an elected interest period plus an applicable margin between 1.75% to 2.75%; or

Table of Contents

an alternate base rate (being the highest of the administrative agent's prime rate, the federal funds effective rate plus 0.5% or 3-month LIBOR plus 1.00%) plus an applicable margin between 0.75% and 1.75%.

The applicable margin varies on a daily basis based on the percentage outstanding under the borrowing base. We incur quarterly commitment fees based on the unused amount of the borrowing base ranging from 0.375% and 0.50% per annum. We may prepay loans under the credit facility at any time without premium or penalty (other than customary LIBOR breakage costs).

The credit facility contains various covenants limiting our ability to:

grant or assume liens;

incur or assume indebtedness;

grant negative pledges or agree to restrict dividends or distributions from subsidiaries;

sell, transfer, assign or convey assets, or engage in certain mergers or acquisitions;

make certain distributions;

make certain loans, advances and investments;

engage in transactions with affiliates;

enter into sale and leaseback, take-or-pay or hydrocarbon prepayment transactions; or

enter into certain swap agreements.

The credit facility also contains covenants requiring us to maintain:

a current ratio of not less than 1.0 to 1.0; and

a debt to EBITDAX coverage ratio of not more than: 4.00 to 1.00 as of the quarter ending March 31, 2011 (using EBITDAX for the quarter then ended multiplied by four); 4.00 to 1.00 as of the quarter ending June 30, 2011 (using EBITDAX for the two quarters then ending multiplied by two); 4.00 to 1.00 as of the quarter ending September 30, 2011 (using EBITDAX for the three quarters then ending multiplied by $^4/_3$); and 4.00 to 1.00 as of the quarter ending December 31, 2011 and each quarter thereafter (using the trailing four-quarter EBITDAX).

As of the nine months ended September 30, 2011, we were in compliance with these ratios.

The credit agreement contains customary events of default, including:

failure to pay any principal, interest, fees, expenses or other amounts when due;

the failure of any representation or warranty to be materially true and correct when made;

failure to observe any agreement, obligation or covenant in the credit agreement, subject to cure periods for certain failures;

a cross-default for the payment of any other indebtedness of at least $2 million;

bankruptcy or insolvency;

judgments against us or our subsidiaries, in excess of $2 million, that are not stayed;

certain ERISA events involving us or our subsidiaries; and

a change in control (as defined in the credit agreement), including the ownership following this offering by a "person" or "group" (as defined under the Securities and Exchange Act of 1934, as amended, but excluding certain permitted stockholders) directly or indirectly, of more than 35% of our common stock.

Table of Contents

Future capital requirements

We believe that the proceeds from this offering and our internally generated cash flow combined with access to our 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. Any decision regarding a future 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 commodity price volatility, which could, among other things, lead to a decline in the borrowing base under our 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.

Contractual Obligations

We have the following contractual obligations and commitments as of September 30, 2011 (in thousands):

	Total	1 Year or Less	2-3 Years	4-5 Years	More Than 5 Years
Credit facility[1]	$ 132,100			$ 132,100	$
Operating leases[2]	2,114	434	895	785	
Asset retirement obligations[3]	6,449	400	400		5,649
	$ 140,663	$ 834	$ 1,295	$ 132,885	$ 5,649

(1) Amount excludes interest on our credit facility as both the amount borrowed and the applicable interest rate is variable. On March 29, 2011, we entered into a new credit agreement, which matures on March 29, 2015.

(2) See Note 7 to our consolidated financial statements for a description of operating leases.

(3) Amount represents our estimate of future retirement obligations on a discounted basis unless otherwise noted. Because these costs typically extend many years into the future, management prepares estimates and makes judgments that are subject to future revisions based upon numerous factors. The $0.4 million included in the one year or less category is not discounted and is included in accounts payable and accrued expenses as of June 30, 2011.

Summary of Estimated Capital Expenditures

The following table summarizes our historical 2010 and our estimated 2011 capital expenditures. Our historical 2010 capital expenditures include 2010 expenditures made by HEC, which was acquired in December 2010. We routinely monitor and adjust our estimated capital expenditures in response to changes in oil and natural gas prices, availability of financing, drilling and acquisition costs, industry conditions, the timing of regulatory approvals, the availability of rigs, success or lack of success in drilling activities, contractual obligations, internally generated cash flows and other factors both within and outside

Table of Contents

our control. See "*Risk Factors Risks Related to the Oil and Natural Gas Industry and Our Business*." We do not budget for acquisitions.

Operation	Historical and Projected Capital Expenditures Years Ended December 31, 2010	2011
	(dollars in thousands)	
Oil and gas property development	$ 44,576	$ 141,328
Gas processing facility and other	4,491	20,806
Total	$ 49,067	$ 162,134

Off-Balance Sheet Arrangements

As of September 30, 2011, we had no material off-balance sheet arrangements. We have no plans to enter into any off-balance sheet arrangements in the foreseeable future.

Critical Accounting Policies

Our discussion and analysis of financial condition and results of operations are based upon the information reported in our consolidated financial statements, which have been prepared in accordance with GAAP. In many cases, the accounting treatment of particular transactions is specifically required by GAAP. The preparation of our financial statements requires us to make estimates and judgments that can affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities at the date of our financial statements. We analyze our estimates and judgments, including those related to oil and natural gas revenues, oil and gas properties, fair value of derivative instruments, contingencies and litigation, and base our estimates and judgments on historical experience and various other assumptions that we believe to be reasonable under the circumstances. Actual results may vary from our estimates. These significant accounting policies are detailed in Note 2 to our consolidated financial statements. We have outlined below certain of these policies as being of particular importance to the portrayal of our financial position and results of operations and which require the application of significant judgment or estimates by our management.

Consolidation and Reporting. Our consolidated financial statements include the accounts of us and our wholly owned subsidiaries, after elimination of all significant intercompany accounts, transactions and profits. Our management has evaluated our consolidation of variable interest entities in accordance with ASC 810, and has concluded that we have no variable interest entities.

Oil and Natural Gas Properties. We utilize the successful efforts method of accounting for our oil and natural gas properties. Under this method of accounting, costs to acquire the mineral interests in oil and natural gas properties, to drill and complete exploratory wells that find proved reserves, and to drill and complete development wells are capitalized when incurred. Costs to drill exploratory wells that do not find proved reserves, delay rentals and geological and geophysical costs are expensed as incurred, other than the costs used to determine a drill site location.

Oil and Natural Gas Reserve Quantities. Our most significant financial estimates are based on estimates of proved oil and natural gas reserves. Estimates of proved reserves are key components of our rate of recording depreciation, depletion and amortization. Numerous uncertainties are inherent in estimating quantities of proved reserves and in projecting future revenues, rates of production and timing of development expenditures, including many factors beyond our control. The estimation process relies on assumptions and interpretations of available geologic, geophysical, engineering and production data, and the accuracy of reserve estimates is a function of the quality and quantity of available data. Our reserves are estimated on an annual basis by independent petroleum engineers.

Asset Retirement Obligations. ASC 410, Asset Retirement and Environmental Obligations, addresses accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. In general, our future asset retirement obligations relate to future costs associated with the plugging and abandonment of our oil and natural gas wells, removal of equipment and facilities from leased acreage and returning such land to its original condition. ASC 410 requires that the fair value of a liability for an asset's retirement obligation be recognized in the period in which it is incurred, discounted to its present value using our credit adjusted risk-free interest rate, and the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted to its then present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Revisions to estimated retirement obligations will result in an adjustment to the related capitalized asset and corresponding liability. If the liability is settled for an amount other than the recorded amount, a gain or loss is recognized.

Revenue Recognition. We recognize revenues from the sales of oil and natural gas when the products are sold and delivery to the purchaser has occurred. Any amounts due from purchasers of oil and natural gas are included in accounts receivable in our consolidated balance sheet.

At times, we may sell more or less than our entitled share of gas production. When this happens, we use the entitlement method of accounting for gas sales, based on our net revenue interest in production. Accordingly, revenue would be deferred for gas deliveries in excess of our net revenue interest, while revenue would be accrued for any undelivered volumes.

Derivative Instruments and Hedging Activities. ASC 815, Derivatives and Hedging, requires that all derivative instruments be recorded on the balance sheet as either assets or liabilities at their respective fair values. We utilize swaps and collars to reduce our exposure to unfavorable changes in oil and natural gas prices. We recognize all derivative instruments on a consolidated balance sheet as either an asset or liability based on fair value and recognize subsequent changes in fair value in earnings unless the derivative instrument qualifies as a hedge. The fair value of the derivative instruments is confirmed monthly by the counterparties to the agreement. Management believes that credit and performance risk with our counterparties is minimal.

We did not designate any of our currently outstanding derivative instruments as hedges for financial statement purposes.

Recently Issued Accounting Pronouncements

Fair Value. In January 2010, the FASB issued authoritative guidance to update certain disclosure requirements and added two new disclosure requirements related to fair value measurements. See Note 11 to our consolidated financial statements included in this prospectus for a more detailed discussion of these requirements. We do not expect the adoption of this new guidance to have a significant impact on our financial position, cash flows or results of operations.

Oil and Gas Reporting Requirements. In December 2008, the SEC released the final rule, "Modernization of Oil and Gas Reporting," which adopts revisions to the SEC's oil and gas reporting disclosure requirements. The disclosure requirements under this final rule require reporting of oil and gas reserves using the unweighted arithmetic average of the first-day-of-the-month price for the preceding twelve months rather than year-end prices, and the use of new technologies to determine proved reserves if those technologies have been demonstrated to result in reliable conclusions about reserves volumes. Companies are required to report the independence and qualifications of their reserves preparer or auditor and file reports when a third party is relied upon to prepare reserves estimates or conduct a reserves audit. In January 2010, the FASB issued authoritative guidance on oil and gas reserve estimation

Table of Contents

and disclosure, aligning their requirements with the SEC's final rule. We have presented and applied this new guidance for the year ended December 31, 2009 herein.

Inflation

Inflation in the United States has been relatively low in recent years and did not have a material impact on our results of operations for the last three fiscal years. Although the impact of inflation has been insignificant in recent years, it is still a factor in the United States economy, and we tend to experience inflationary pressure on the cost of oilfield services and equipment as increasing oil and gas prices result in increased drilling activity in our areas of operations.

Quantitative and Qualitative Disclosures on Market Risks

Oil and Natural Gas Prices. Our financial condition, results of operations and capital resources are highly dependent upon the prevailing market prices of oil and natural gas. These commodity prices are subject to wide fluctuations and market uncertainties due to a variety of factors that are beyond our control. Factors influencing oil and natural gas prices include the level of global demand for oil, the global supply of oil and natural gas, the establishment of and compliance with production quotas by oil exporting countries, weather conditions which determine the demand for natural gas, the price and availability of alternative fuels and overall economic conditions. It is impossible to predict future oil and natural gas prices with any degree of certainty. Sustained weakness in oil and natural gas prices may adversely affect our financial condition and results of operations, and may also reduce the amount of oil and natural gas reserves that we can produce economically. Any reduction in our oil and natural gas reserves, including reductions due to price fluctuations, can have an adverse affect on our ability to obtain capital for our exploration and development activities. Similarly, any improvements in oil and natural gas prices can have a favorable impact on our financial condition, results of operations and capital resources. If oil prices decline by $10.00 per Bbl, then our PV-10 as of December 31, 2010 would have been lower by approximately $100.4 million. If natural gas prices decline by $1.00 per Mcf, then our PV-10 as of December 31, 2010 would decrease by approximately $32.9 million.

Our primary commodity risk management objective is to reduce volatility in our cash flows. Management makes recommendations on hedging that are approved by the board of directors before implementation. We enter into hedges for oil and natural gas using NYMEX futures or over-the-counter derivative financial instruments with only certain well-capitalized counterparties which have been approved by our board of directors.

The use of financial instruments may expose us to the risk of financial loss in certain circumstances, including instances when (1) sales volumes are less than expected requiring market purchases to meet commitments, or (2) our counterparties fail to purchase the contracted quantities of natural gas or otherwise fail to perform. To the extent that we engage in hedging activities, we may be prevented from realizing the benefits of favorable price changes in the physical market. However, we are similarly insulated against decreases in such prices. For a discussion of the hedges that we had in place as of April 30, 2011, see "*Business Hedging Activity*."

Presently, all of our hedging arrangements are concentrated with two counterparties, both of which are lenders under our credit facility. If this counterparty fails to perform its obligations, we may suffer financial loss or be prevented from realizing the benefits of favorable price changes in the physical market.

The result of natural gas market prices exceeding our swap prices or collar ceilings requires us to make payment for the settlement of our hedge derivatives, if owed by us, generally up to three business days before we receive market price cash payments from our customers. This could have a material adverse effect on our cash flows for the period between hedge settlement and payment for revenues earned.

Table of Contents

The following table provides a summary of derivative contracts as of October 31, 2011:

Settlement Period	Derivative Instrument	Total Notional Amount (Bbl/Mmbtu)	Average Floor Price	Average Ceiling Price	Fair Market Value of Asset (Liability)
					(In thousands)
Oil					
2011	Collar	239,552	$ 83.86	$ 133.45	$ 355
	Swap	62,428	64.36	64.36	(2,028)
2012	Collar	167,472	90.00	123.00	570
	Swap	116,708	63.03	63.03	(4,285)
2013	Collar	50,616	90.00	123.00	163
	Swap	75,417	61.50	61.50	(2,923)
Gas					
2011	Swap	108,580	7.10	7.10	285
2012	Swap	202,319	6.75	6.75	386
2013	Swap	154,806	6.40	6.40	199
					$ (7,278)

Interest Rates. We intend to use the net proceeds from this offering to repay all outstanding indebtedness under our credit facility. At October 31, 2011, we had $149.1 million outstanding under our credit facility, which is subject to floating market rates of interest. Borrowings under our credit facility bear interest at a fluctuating rate that is tied to an adjusted base rate or LIBOR, at our option. Any increases in these interest rates can have an adverse impact on our results of operations and cash flow. Based on borrowings outstanding at October 31, 2011, a 100 basis point change in interest rates would change our annualized interest expense by approximately $1.5 million.

Counterparty and customer credit risk. In connection with our hedging activity, we have exposure to financial institutions in the form of derivative transactions. The lenders under our credit facility are currently the counterparties on our derivative instruments currently in place and have investment grade credit ratings. We expect that any future derivative transactions we enter into will be with these or other lenders under our credit facility that will carry an investment grade credit rating.

We are also subject to credit risk due to concentration of our oil and natural gas receivables with certain significant customers. See "*Business Principal Customers*" for further detail about our significant customers. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. We review the credit rating, payment history and financial resources of our customers, but we do not require our customers to post collateral.

Table of Contents

BUSINESS

Overview

Bonanza Creek Energy, Inc. is an independent oil and natural gas company engaged in the acquisition, exploration, development and production of onshore oil and associated liquids-rich natural gas in the United States. Our assets and operations are concentrated primarily in southern Arkansas (Mid-Continent region) and the DJ and North Park Basins in Colorado (Rocky Mountain region). In addition, we own and operate oil producing assets in the San Joaquin Basin (California region). Our management team has extensive experience acquiring and operating oil and gas properties, which we believe will contribute to the development of our sizable inventory of projects including those targeting the oily Cotton Valley sands in our Mid-Continent region and the Niobrara oil shale formation in our Rocky Mountain region. We operate approximately 99.4% and hold an average working interest of approximately 85.8% of our proved reserves, providing us with significant control over the rate of development of our long-lived, low-cost asset base.

Cawley, Gillespie & Associates, Inc., our independent reserve engineers, estimated our net proved reserves as of December 31, 2010, to be as follows:

Estimated Proved Reserves	Crude Oil (MBbls)	Natural Gas (MMcf)	Natural Gas Liquids (MBbls)	Total Proved (MBoe)
Developed				
Mid-Continent	3,725	9,094	745	5,985
Rocky Mountain	3,373	10,961		5,200
California	337	19		340
Undeveloped				
Mid-Continent	7,898	35,754	3,033	16,890
Rocky Mountain	2,729	7,011		3,898
California	539	45		547
Total Proved	18,601	62,884	3,778	32,860

Our average net daily production rate during October 2011 was 4,813 Boe/d, which consisted of 72.5% oil and natural gas liquids.

	Estimated Proved Reserves at December 31, 2010[1]					Estimated Production for the Month Ended October 31, 2011		Projected 2011 Capital Expenditures (millions)[3]	Net Proved Undeveloped Drilling Locations as of December 31, 2010
	Total Proved (MBoe)	% of Total	% Proved Developed	% Oil and Liquids	PV-10 ($ in MM)[2]	Average Net Daily Production (Boe/d)	% of Total		
Mid-Continent	22,876	69.6%	26.2%	67.3%	$ 313.3	2,545	52.9%	$ 85.2	151.3
Rocky Mountain	9,098	27.7	57.2	67.1	135.3	2,085	43.3	74.9	77.3
California	886	2.7	38.3	98.8	13.0	183	3.8	2.0	13.6
Total	32,860	100.0%	35.1%	68.1%	$ 461.6	4,813	100%	$ 162.1	242.2

(1) Proved reserves were calculated using prices equal to the twelve-month unweighted arithmetic average of the first-day-of-the-month prices for each of the preceding twelve months which were $79.43 per Bbl of crude oil and an average price of $4.38 per MMBtu of

natural gas. Adjustments were

made for location and the grade of the underlying resource, which resulted in $4.50 per Bbl of crude oil and an increase of $0.43 per MMBtu of natural gas.

(2)
PV-10 is a non-GAAP financial measure and represents the present value of estimated future cash inflows from proved crude oil and natural gas reserves, less future development and production costs, discounted at 10% per annum to reflect timing of future cash inflows and using the twelve month unweighted arithmetic average of the first-day-of-the-month price for each of the preceding twelve months. PV-10 differs from Standardized Measure because it does not include the effect of future income taxes. For a reconciliation of our Standardized Measure to PV-10, see "*Summary Reserve and Operations Data Non-GAAP Financial Measures and Reconciliation PV-10*."

(3)
Projected capital expenditures for our Mid-Continent region include $17.7 million for the construction of the Dorcheat gas processing facility, which was completed in September 2011.

Development Projects by Region

Mid-Continent: In southern Arkansas we are primarily targeting the oil-bearing Cotton Valley sands in the Dorcheat Macedonia and McKamie Patton fields. As of December 31, 2010, our estimated proved reserves in this region were 22,876 MBoe, 67.3% of which were oil and natural gas liquids and 26.2% of which were proved developed. We currently operate 135 gross (116.8 net) producing wells and, as of December 31, 2010, have an identified drilling inventory of approximately 188 gross (151.3 net) PUD drilling locations on our acreage. In 2011 we expect to drill and complete 40 gross (34.8 net) wells in the Dorcheat Macedonia field at a cost of approximately $1.7 million per well, and 2 gross (2.0 net) wells in the McKamie Patton field at a cost of $1.2 million per well. As of October 31, 2011 we had drilled 36 gross (31.5 net) wells in the Dorcheat Macedonia field. This activity brings our current operated well count to 138 gross (120.5 net) producing wells.

We also own and operate the McKamie and Dorcheat gas processing facilities and approximately 150 miles of associated gathering pipelines that serve our acreage position in southern Arkansas. These facilities have a combined maximum processing capacity of 27.5 MMcf/d of natural gas and 30,000 gallons per day of natural gas liquids. These two facilities currently process all of the natural gas that we produce from the Dorcheat Macedonia and McKamie Patton fields.

Rocky Mountain: In the DJ and North Park Basins in Colorado, we hold 83,617 gross (62,688 net) acres that currently produce oil, natural gas and CO_2 from the Pierre B, Niobrara, Codell, J-Sand, D-Sand and Dakota formations. As of December 31, 2010, our estimated proved reserves in this region were 9,098 MBoe, of which 67.1% were oil and 57.2% were proved developed. In the DJ Basin we control 29,262 net acres, as of December 31, 2010, and have identified approximately 93 gross (73.3 net) vertical PUD drilling locations targeting the Codell sand and Niobrara oil shale formations. In 2011, we expect to drill and complete 63 gross (62.8 net) vertical wells targeting the Codell sand and Niobrara oil shale formations, at a cost of approximately $0.8 million per well. As of October 31, 2011, we had completed 59 gross (59.0 net) of our planned 2011 wells. In addition, we believe that horizontal drilling and multi-stage fracture completion techniques are an attractive alternative to vertical well completions for the Niobrara oil shale. To date, we have drilled all four, and completed three, of our operated horizontal Niobrara wells in the DJ Basin planned for 2011. In the North Park Basin we control 33,426 net acres and, as of December 31, 2010, have identified four gross (4.0 net) vertical PUD locations. We have identified highly fractured and dual porosity areas which we believe will support vertical and horizontal drilling techniques for the Niobrara. The development and testing of the North Park Basin began this year with the drilling of 2 gross (2.0 net) vertical wells at a drilling and evaluation cost of approximately $2.9 million for the first well and an estimated $2.2 million for the second well.

California: In California, we employ thermal techniques to recover heavy oil in the Kern River and Midway Sunset fields, and we produce medium gravity oil from the Greeley and Sargent fields. As of December 31, 2010, our estimated proved reserves in this region were 886 MBoe, of which 98.8% were oil

Table of Contents

and 38.3% were proved developed. We have identified approximately 18 gross (13.6 net) PUD drilling opportunities in these fields. In 2011, we expect to drill 3 gross (1.5 net) wells with individual well costs ranging from approximately $0.3 to $1.0 million. As of October 31, 2011, we have drilled and completed 3 gross (1.5 net) wells.

Recent Developments

On July 24, 2011, we completed our first operated horizontal Niobrara well, the State Antelope 11-2Hz, and reported a 24-hour rate after cleanup on August 1, 2011 of 738 Boe/d and a 30-day rate of 362 Boe/d. Our second operated horizontal Niobrara well, the North Platte 44-11-28Hz, was completed on August 9, 2011 and reported a 24-hour rate after cleanup on August 19, 2011 of 887 Boe/d and a 30-day rate of 599 Boe/d. These two wells cost an average of $3.9 million per well. We recently completed our third operated horizontal Niobrara well, the State Antelope 11-14-1Hz, reporting a 24-hour rate after cleanup on November 1, 2011 of 886 Boe/d. Our fourth and final operated horizontal Niobrara well of 2011, the State Whitetail 14-11-36Hz, has been drilled and is currently being fracture stimulated. We expect costs for these two wells to average $4.3 million per well.

Our Business Strategies

Our goal is to increase stockholder value by investing capital to increase our production, cash flow and proved reserves. We intend to accomplish this goal by focusing on the following key strategies:

Increase Production from Existing Low-Cost Proved Inventory. In the near term, we intend to accelerate the drilling of our lower-risk vertical PUD drilling locations in southern Arkansas and in the oily Codell and Niobrara formation of the DJ Basin. Substantially all of these infill locations are characterized by multiple productive horizons.

Test and Evaluate Our Niobrara Oil Shale Acreage. We hold approximately 83,617 gross (62,688 net) acres prospective for the development of the Niobrara oil shale in Weld and Jackson Counties, Colorado, and own approximately 17,400 acres of proprietary 3-D seismic data covering our acreage position in Weld County, which aids in identifying our horizontal drilling locations. Although full-scale vertical drilling of the Niobrara oil shale commenced in the early 1990s, we and other operators in the region, including EOG Resources (DJ Basin and North Park Basin), Noble Energy (DJ Basin), and PDC Energy (DJ Basin) have recently applied horizontal drilling and multi-stage fracture stimulation techniques to enhance recoveries and economic returns.

Exploit Additional Development Opportunities. We are evaluating additional resource potential opportunities that could result in future development projects on several of our assets. For example, we have evaluated and believe we may achieve attractive returns by exploiting the Lower Smackover (Brown Dense) trend in our southern Arkansas acreage. We have 5,672 net acres prospective for the Brown Dense. Finally, we believe there are additional thermal recovery opportunities in California.

Pursue Accretive Acquisitions. We intend to pursue bolt-on acquisitions in regions where we operate and where we believe we possess a strategic or technical advantage, such as southern Arkansas where we own a gas processing facility and the associated infrastructure. In addition, we intend to focus on other oil and liquids-rich opportunities where we believe our operational experience will enhance the value and performance of acquired properties.

Maintain High Degree of Operatorship. We currently have and intend to maintain a high working interest in our assets, thereby allowing us to leverage our technical, operating and management skills and control the timing of our capital expenditures.

Table of Contents

Our Competitive Strengths

We believe the following combination of strengths will enable us to implement our strategies:

Significant Drilling Inventory. We have identified 303 gross (242.2 net) PUD drilling locations, providing us with multiple years of drilling inventory.

Niobrara Resource Potential. Since 2005, we have accumulated 62,688 net acres in Weld and Jackson Counties, Colorado, targeting the Niobrara formation. Our acreage is proximate to horizontal drilling operations which have been successfully completed by other operators. Significant increases in permitting, spud notices involving the Niobrara formation in these counties have made this area one of the most active oil shale plays in the United States. In Weld County the average initial 30-day production rate is 318 Boe/d from 70 wells with oil and gas production and no dry holes reported to the state regulatory commission. In the North Park Basin, EOG Resources has completed seven wells horizontally in an area of the Niobrara that we believe to be geologically similar to our acreage position based on electric and porosity log response. The average initial 30-day production rate for these wells is 294 Boe/d.

We believe our significant acreage position in the Niobrara represents production, reserve and value growth potential and that the continued development of this play by other operators validates our investment in this play and will result in the continued development of infrastructure in the area. Geological risks associated with our Weld County acreage position have been mitigated by the high volume of data provided through the drilling, completion and production of thousands of vertical wells in the Niobrara in close proximity to and within our acreage. Additionally, since oil and gas production has been established, gathering systems are in place in this region, enabling a short time period from well completion to first product sales.

In Weld County, we own approximately 17,400 acres of proprietary 3-D seismic. Because we have exclusive access to this data, we are in a position to preferentially orient horizontal wells targeting the Niobrara on our acreage position and have the ability to identify and avoid drilling hazards, such as faulting.

In Jackson County, we own 22 proprietary 2-D seismic lines. Interpretation of this proprietary seismic data affords us the geologic image necessary to plan our Niobrara development program. In addition, our position of 39,030 net acres provides us with economies of scale to develop the Niobrara, as well as to explore the resource potential in other horizons.

While there is currently no pipeline capacity in Jackson County to move natural gas to market, successful drilling of horizontal Niobrara wells by us or other operators would likely justify installation of gas pipeline infrastructure.

High Degree of Operational Control. We hold an average working interest in our properties of approximately 85.8% and operate approximately 99.4% of our estimated proved reserves, which allows us to employ the drilling and completion techniques we believe to be most effective, manage costs and control the timing and allocation of our capital expenditures.

Gas Processing Capability in Southern Arkansas. The processing of our natural gas at our McKamie facility improves our well development economics in southern Arkansas. In addition, we expanded our infrastructure by adding an additional gas processing facility in our Dorcheat Macedonia field to accommodate future drilling on our acreage in this region.

Experienced Management. Our senior management team averages more than 28 years of industry experience, and certain members of our executive management have worked together for over 24 years. Our management team has significant acquisition experience, having negotiated and closed more than 12 acquisition transactions since 2006.

Table of Contents

Financial Flexibility. Our capital structure is intended to provide a high degree of financial flexibility to grow our asset base, both through organic projects and opportunistic acquisitions. Immediately following the completion of this offering, we expect to have no indebtedness and $ million of liquidity, comprised of $220 million of availability under our credit facility and approximately $ million of cash on hand.

Bonanza Creek Acquisition History

Acquiring properties that are complementary to our existing positions or that have significant undeveloped resource potential has been an important part of our growth strategy. The following describes some of the recent acquisitions we have made to build our current position in the Mid-Continent, the Rocky Mountain and California regions:

Mid-Continent. In April 2008, we acquired properties in Union, Lafayette and Columbia counties, Arkansas, that included 93 producing wells (68 operated) with an average working interest of 73% and 14,980 gross (12,147 net) acres. Included in the acquisition was a 15 MMcf/d gas plant with approximately 150 miles of gathering system, which processes production from both the properties and other producers in the area. We acquired 3,469 gross (3,018 net) acres in the Dorcheat Macedonia Field, Columbia County, Arkansas in December 2010. The assets included a non-operated position in our Dorcheat Macedonia field as well as operated wells in which we were a non-operated owner.

Rocky Mountain. We completed four DJ Basin acquisitions in 2005 and 2006, consisting of approximately 39,728 gross (27,463 net) acres. In December 2010, we purchased an additional 2,970 gross (2,279 net) acres in the DJ Basin, including 39 operated and 3 non-operated wells primarily completed in the Codell/Niobrara formations. We purchased the McCallum Field, located in the North Park Basin, Jackson County, Colorado in May 2006, along with 2 non-producing wells and undeveloped acreage in November 2007.

California. In 2006 and 2007, we acquired 8,940 gross (5,012 net) acres in Kern and Santa Clara Counties, California consisting of a mix of heavy and light oil producing assets.

Our Operations

Our operations are mainly focused in the Mid-Continent, specifically the Dorcheat Macedonia field located in Columbia County, Arkansas and in the DJ Basin and the North Park Basin in the Rocky Mountain region.

Mid-Continent Region

Substantially all of our proved reserves and our identified PUD drilling locations in our Mid-Continent acreage are located in the Dorcheat Macedonia field and the McKamie Patton field.

Dorcheat Macedonia

In the Dorcheat Macedonia field we average a 84.2% working interest and 69.5% net revenue interest, and all of our acreage is held by production. We have approximately 101 gross (85.0 net) producing wells and our average net daily production during October 2011 was approximately 1,576 Boe/d from a proved reserves base of 15,247 MBoe, of which about 64.5% is oil and natural gas liquids. Productive reservoirs range in depth from 4,500 to 9,000 feet in depth. Those reservoirs have included the Smackover, Cotton Valley and the Pettet. Our primary development target is the Cotton Valley.

The Dorcheat Macedonia field was originally developed for the Smackover in the 1940s on 80-acre units with the initial well drilled in the center of the unit. The Cotton Valley and shallower reservoirs were developed in the 1970s and 1980s. Field rules for the development of the Cotton Valley provided for the drilling of a Cotton Valley well in the center of the two 40-acre tracts that comprised the 80-acre unit, with a location tolerance of no more than 150 feet from a straight line between the two centers of the 40 acres, which resulted in two Cotton Valley wells and a Smackover well confined to an 11-acre oval within the center of the unit, leaving 69 acres within each unit without a wellbore penetration. Subsequent development of the Cotton Valley has reduced the spacing to approximately 20 acres in certain areas of the field, and our continued development will ultimately reduce spacing to ten acres. The oil-bearing Cotton Valley sands directly overlie the Bossier Shale and have relatively low porosity and permeability. Deposited as a series of sand and shale sequences, the resulting reservoir is extremely lenticular in nature. Based on reservoir parameters, fracture stimulation is employed to complete these multiple stacked pay zones. The oil in these sands has an American Petroleum Institute (API) gravity of approximately 45° and is primarily lifted by rod pump.

Historically, the Dorcheat Macedonia reservoirs have responded favorably to fracture stimulation. Beginning in the fourth quarter of 2009 we began to implement pinpoint fracture stimulation utilizing coiled tubing. Post-fracture treatment tracer work has confirmed that pinpoint fracture placement provides much better coverage and penetration of the intended producing intervals. Early results from wells employing this technique have seen initial production rates higher than historic and show stimulation of previously unstimulated zones.

As of December 31, 2010, we have identified approximately 179 gross (142.6 net) PUD drilling locations on our acreage in this area. Currently, we have budgeted for 2011 capital expenditures of $54.4 million for the development of our Dorcheat Macedonia acreage. Under this budget we expect to drill 40 gross (34.9 net) additional infill PUD locations in the field this year. We expect to drill vertically to an average depth of approximately 8,700 feet for each location with a total expected drill and complete cost per well of approximately $1.7 million, approximately $1.6 million of which will be for initial drilling and completion. Typically, these wells take an average of 12 days to drill and three days to complete. The average initial 30-day production rate for the 41 wells we drilled in the Dorcheat Macedonia field and had on production since October 2009 was 137 Boe/d. Our typical well has a hyperbolic decline rate and an average economic life of 22 years. As of October 31, 2011, we have drilled 36 gross (31.5 net) of the planned 2011 wells.

Other Mid-Continent

We own additional interests in the Mid-Continent region near the Dorcheat Macedonia field. These include interests in the McKamie-Patton, Atlanta and Beach Creek fields. Our estimated proved reserves in these fields as of December 31, 2010 were approximately 1,947.8 MBoe, and average net daily production during October 2011 was approximately 221 Boe/d. We plan to drill 2 gross (2.0 net) wells in the McKamie-Patton field in 2011 at a cost of $1.2 million per well.

Gas Processing Facilities

The McKamie processing facility is located in Lafayette County, Arkansas and is strategically located to serve our production in the region. This facility has a processing capacity of 15 MMcf/d of natural gas and 30,000 gallons per day of natural gas liquids. The facility processes natural gas and natural gas liquids, fractionates liquids into three components for sale, and sells four products at the facility's tailgate: propane, butane, natural gasolines and natural gas. The facility is a Process Safety Management maintained facility, and the main components were placed into service in the mid-1980s. The facility is currently processing approximately 10 MMcf/d of natural gas comprised of 9.2 MMcf/d of Bonanza-operated natural gas and 0.8 MMcf/d of third-party natural gas. We also own approximately 150 miles of natural gas gathering pipeline that serves the facility and surrounding field areas and 32 miles of right-of-way crossing Lafayette County that can be utilized to connect the facility to other gas fields or future sales outlets. Natural gas is sold at the tailgate of the facility into a CenterPoint pipeline connection. Fractionated natural gas liquids are held on site and trucked out by the buyer, Dufour Petroleum. All gas entering the facility is processed in accordance with percent-of-proceeds contracts with upstream counterparties.

In order to accommodate increased gas volumes, we invested $17.7 million to build a 12.5 MMcf/d processing facility with associated 28,000 gallons per day of natural gas liquids capacity in our Dorcheat Macedonia field, which we completed in September of this year. The construction of this new facility is in conjunction with our continued development of the field. In November 2011, we executed an agreement for the expansion of this facility. Our capital commitments under this agreement are $7.5 million, which is a portion of the total cost for the expansion. We spent an additional $2.5 million on facilities throughout the company.

Combined, the facilities had an average net output of 748 Boe/d based on the facility contracts for the month of October, 2011. Our ownership of this facility and pipeline system provides us with the benefit of controlling processing and compression of our natural gas production and timing of connection to our newly completed wells. While we own the majority of the gas entering the facility, we also process some third-party natural gas through the system. Neither the revenue nor volumes of this third-party natural gas is included in our reserve reports.

Rocky Mountain Region

The two main areas in which we operate in the Rocky Mountain region are the DJ Basin in Weld County, Colorado and the North Park Basin in Jackson County, Colorado. The Niobrara oil shale is present across substantially all of our acreage in these two areas.

While full-scale vertical drilling of the Niobrara oil shale commenced in the early 1990s, operators in the region, including EOG Resources, Noble Energy and PDC Energy, have recently applied horizontal drilling and multi-stage fracture stimulation techniques in an effort to improve economic returns.

The Niobrara oil shale contains a high proportion of carbonates, including brittle, calcareous chalk benches in addition to oil bearing shales. Permeability and porosity are sufficient in the chalk components of the Niobrara to permit economic oil recovery. Although natural fracturing is present in the Niobrara, hydraulic fracturing is typically required to make the reservoir commercially productive.

The DJ Basin is believed to occupy the most prospective area of the Niobrara. Within the DJ Basin, the Niobrara oil shale is 200 to 300 feet thick and comprises the Smoky Hill Shale and Fort Hayes Limestone. In addition to the DJ Basin, Niobrara oil shale exploration is ongoing in the North Park, Piceance, Raton and Sand Wash basins in Colorado and the southern Powder River Basin in Wyoming.

Recently the Niobrara oil shale has been the scene of increasing interest as various companies such as EOG Resources, Noble Energy, PDC Energy and Rex Energy are leasing, permitting and drilling wells targeting the Niobrara oil shale in Weld County, Colorado, the North Park Basin in Jackson County, Colorado, and in Laramie County, Wyoming. These operators have demonstrated that the Niobrara oil shale is prospective for the application of horizontal drilling and multi-stage fracture stimulation completion techniques. These completion techniques have been responsible for the substantial increase in drilling and production from various oil shales such as the Bakken formation in North Dakota and the Eagle Ford in southern Texas.

DJ Basin Weld County, Colorado

The DJ Basin is a geologic structural basin centered in eastern Colorado that extends into southeast Wyoming, western Nebraska, and western Kansas. Our operations in the DJ Basin are in the oil window of the Niobrara and as of October 31, 2011 consisted of approximately 42,218 gross (29,262 net) total acres.

Commercial development activities began in the DJ Basin in the 1970s. It originally produced natural gas from tight sand reservoirs in the Dakota and J Sands. In the 1990s the shallower Codell sands and

Table of Contents

Niobrara oil shale were developed and produced oil and associated natural gas. These zones range from 6,300 feet to 8,000 feet with average porosity of 6% to 10% and relatively low permeability of 0.3 millidarcies.

Historically, we have drilled vertical wells through multiple zones. We then complete and fracture stimulate one of the Dakota or J Sand zones or both the Codell sand and the Niobrara shale zones. We are beginning to augment the vertical development of our Weld County acreage using horizontal drilling techniques in the Niobrara oil shale.

DJ Basin Vertical Exploitation

Our estimated proved reserves in the DJ Basin were 8,402 MBoe at December 31, 2010. As of October 31, 2011, we had a total of 178 gross (170.8 net) producing wells and our net average daily production during October 2011 was approximately 1,497 Boe/d. Our working interest for all producing wells averages 95.9% and our net revenue interest is approximately 78.7%.

We drill wells vertically in this area to an average depth of approximately 7,000 feet, targeting both the Niobrara and Codell horizons with the same well bore. We have budgeted drilling and completion costs per well of approximately $640,000 and we expect to incur an additional $195,000 per well for refracture stimulation, to be completed in the fifth year after initial completion. Typically, these wells take an average of five days to drill and one day to complete. The average initial 30-day production rate for the 35 wells drilled and producing in 2010 was 56 Boe/d. Our typical well has a hyperbolic decline rate and an average economic life of 32 years. As of December 31, 2010, we have identified approximately 93 gross (73.3 net) PUD vertical drilling locations on our acreage in this area.

We intend to employ a mixture of vertical and horizontal drilling techniques with multi-stage fracture completions across our entire Weld County acreage position. Of these acres, 1,640 gross (1,338 net) acres represent proved drilling locations and 19,758 gross (9,798 net) acres represent unproven drilling locations.

The Codell sandstone and Niobrara oil shale are blanket deposits in the DJ Basin. We continue to expand our proved acreage with our vertical program by drilling non-proved locations. Currently, we estimate our capital expenditures for 2011 will be $43.7 million, which includes drilling 63 gross (62.8 net) vertical wells of which 14 are proved and 49 are non-proved. As of October 31, 2011, we had completed 59 gross (59.0 net) of our 2011 planned wells, 12 proved and 47 non-proved.

DJ Basin Horizontal Exploitation

Our entire 42,218 gross (29,262 net) acre position in Weld County is prospective for the Niobrara formation using horizontal drilling and multi-stage fracture completion technology. We have 3-D seismic data covering 17,400 gross acres in this area, in addition to having drilled 19 vertical wells and currently operating 31 vertical wells, further delineating the play for horizontal development.

Table of Contents

Our acreage position in the DJ Basin is offset by Anadarko Petroleum, EOG Resources, Marathon Oil, Noble Energy, and PDC Energy. Noble and PDC have drilled horizontal wells in the area of our acreage and reported initial production rates ranging from 162 Boe/d to 895 Boe/d. Wells on the lower range tend to have shorter horizontal lateral lengths and smaller volumes of proppant used in the fracture stimulation. Noble Energy recently announced the results of the 70 Ranch USX BB #25-99HZ located within our acreage. The reported initial production rate was 895 Boe/d with a 30-day average of 406 Boe/d. The well was completed with a 3,540 foot lateral in the Niobrara B interval. A fracture stimulation treatment was executed with 3.9 million pounds of proppant. In addition, Anadarko is producing from 11 horizontal wells within the Wattenberg field, achieving strong initial rates with high liquids yields, averaging initial production rates of approximately 850 Boe/d. Its best horizontal well to date, the Dolph 27-1HZ, demonstrated an initial production rate of 1,505 Boe/d. We estimate that our capital expenditures for 2011 will be $18.1 million, which includes drilling 4 gross (3.8 net) wells. We completed our first operated horizontal Niobrara well, the State Antelope 11-2Hz, on July 24, 2011 and reported a 24-hour rate after cleanup on August 1, 2011 of 738 Boe/d and a 30-day average rate of 362 Boe/d. Our second operated horizontal Niobrara well, the North Platte 44-11-28Hz, was completed on August 9, 2011 and reported a 24-hour rate after cleanup on August 19, 2011 of 887 Boe/d and a 30-day rate of 599 Boe/d. We recently completed our third operated horizontal Niobrara well, the State Antelope 11-14-1Hz, reporting a 24-hour rate after cleanup on November 1, 2011 of 866 Boe/d. Our fourth and final operated horizontal Niobrara well of 2011 has been drilled and is currently being fracture stimulated. The cost of the first two wells averaged $3.9 million, not including $0.5 million of non-recurring costs relating to micro-seismic and the use of radioactive tracers and $0.4 million of future shared costs with other wells. We anticipate costs for the remaining two wells to average $4.3 million per well.

North Park Basin Jackson County, Colorado

Current Operations. We control 41,399 gross (33,426 net) acres in the North Park Basin in northern Jackson County, Colorado and, as of December 30, 2010, have identified four gross (4.0 net) vertical PUD locations. The Basin is divided into three principal opportunities: the North and South McCallum units and the non-unit acreage. We operate the North and South McCallum fields, which currently produce CO_2 and light oil from the Dakota/Lakota Group sandstones and oil from a shallow waterflood from the Pierre B sandstone.

The McCallum field covers 10,277 gross (8,606 net) acres of federal land with the majority of the oil production coming from a waterflood in the Pierre B formation and the CO_2 production coming from naturally flowing Dakota wells. Oil production is trucked to the market while CO_2 production is sent to a Praxair plant for processing and delivery to the market.

In the North Park Basin, our estimated proved reserves as of December 31, 2010 were approximately 696.1 MBoe, of which 100% were oil. Our average net production during October 2011 was approximately 151 Boe/d. None of our CO_2 production is currently reflected in our reserve reports.

Niobrara Oil Shale Potential. All of our 41,399 gross (33,426 net) acres in the North Park Basin are prospective for the Niobrara oil shale. In 2007, EOG Resources began a testing program in the North Park Basin. As of October 31, 2011 EOG Resources has reported production on seven horizontal wells targeting the Niobrara. The average initial 30-day production rate from these wells has been 294 Boe/d.

We currently plan to drill vertical wells to develop the Niobrara across the top of the McCallum anticline due to the presence of natural fracturing and the potential for other productive horizontals including the Pierre B, Dakota/Lakota, Sundance and Jelm reservoirs. We also plan to drill horizontal wells and, to a lesser extent, vertical wells to capture the Niobrara oil shale resource downdip of the crest of the McCallum structure.

Currently, there is no take away capacity for natural gas from the North Park Basin. Any future commercial development of the Niobrara oil shale in this area will require significant investment to

Table of Contents

construct the infrastructure necessary to gather and transport associated natural gas produced