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

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As filed with the Securities and Exchange Commission on July 25, 2011

Registration No. 333-174765

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Amendment No. 1
to

Form S-1

REGISTRATION STATEMENT
UNDER
THE SECURITIES ACT OF 1933

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 **J. Michael Chambers**

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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

CALCULATION OF REGISTRATION FEE

Title of Each Class of Securities to be Registered	**Proposed Maximum Aggregate Offering Price(1)**	**Amount of Registration Fee(2)(3)**
Common Stock, par value $0.001 per share	$200,000,000	$23,220

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

(2) Calculated pursuant to Rule 457(o) under the Securities Act of 1933.

(3) A registration free of $23,220 was paid previously based on an estimate of the aggregate offering price.

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

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PROSPECTUS (Subject to Completion)
Issued July 25, 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.

We intend to apply to list our common stock on the New York Stock Exchange 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 Company***	***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

, 2011

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You should rely only on the information contained in this prospectus and any free writing prospectus prepared by or on behalf of us or to which we have referred you. Neither we nor the selling 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. Although we believe these third-party sources are reliable and that the information is accurate and complete, we have not independently verified the information.

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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 125 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 April 2011 was 3,691 Boe/d, which consisted of 71.9% oil and natural gas liquids.

	Estimated Proved Reserves at December 31, 2010(1)					Estimated Production for the Month Ended April 30, 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	2,236	60.6%	$ 72.6	151.3
Rocky Mountain	9,098	27.7	57.2	67.1	135.3	1,237	33.5	70.2	75.8
California	886	2.7	38.3	98.8	13.0	218	5.9	8.7	13.6
Total	32,860	100.0%	35.1%	68.1%	$ 461.6	3,691	100%	$ 151.5	240.7

(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

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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 an estimated $16.2 million allocated for a new Dorcheat gas processing facility scheduled to be completed in August 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 111 gross (96.7 net) producing wells and 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 (31.4 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.

We also own and operate the McKamie gas processing facility and approximately 150 miles of associated gathering pipelines that serve our acreage position in southern Arkansas. This facility has a maximum processing capacity of 15 MMcf/d of natural gas and 30,000 gallons per day of natural gas liquids, and we are in the process of building a new 12.5 MMcf/d gas processing facility in the Dorcheat field to allow for continued field development and production growth. Our McKamie facility currently processes all of the natural gas that we produce from the Dorcheat and McKamie fields.

Rocky Mountain: In the DJ and North Park Basins in Colorado, we hold 89,701 gross (68,772 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 29,742 net acres and have identified approximately 91 gross (75.8 net) vertical PUD drilling locations targeting the Codell sand and Niobrara oil shale formations. In 2011, we expect to drill and complete 66 gross (62.3 net) vertical wells targeting the Codell sand and Niobrara oil shale formations, at a cost of approximately $0.8 million per well. 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. In June 2011, we initiated horizontal development of the Niobrara oil shale by commencing drilling the first in a series of 4 gross (3.8 net) horizontal wells at a cost of approximately $3.7 million per well on our DJ Basin properties. In the North Park Basin we control 39,030 net acres and have identified highly fractured and dual porosity areas which we believe will support vertical and horizontal drilling techniques for the Niobrara. The development of the North Park Basin will begin in 2011 with the drilling of 7 gross (7.0 net) vertical wells at a cost of approximately $1.9 million per 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 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 10 gross (8.0 net) wells with individual well costs ranging from approximately $0.3 to $1.0 million.

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 89,701 gross (68,772 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, 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. We expect to drill four Niobrara horizontal wells in the DJ Basin (Weld County, Colorado) in 2011.

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 trend in our southern Arkansas acreage and 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.

Our Competitive Strengths

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

Significant Drilling Inventory. We have identified 297 gross (240.7 net) PUD drilling locations, providing us with multiple years of drilling inventory.

Niobrara Resource Potential. Since 2005, we have accumulated 68,772 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 311 Boe/d from 32 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 5 wells horizontally in an area of the Niobrara that we believe to be

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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 323 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 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. We are in the process of expanding our infrastructure by adding an additional gas processing facility in our Dorcheat 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 $130 million of availability under our credit facility and approximately $ million of cash on hand.

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 the "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;

- 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.

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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. 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

Upon 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 common stock pursuant to a formula set forth in our 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 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 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 15 and "*Cautionary Note Regarding Forward-Looking Statements*."

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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 42.62% 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.

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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 April 30, 2011, was approximately $68.4 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.
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*."
Proposed New York Stock Exchange listing	We intend to apply to list shares of our common stock on the NYSE under the symbol "BCEI" soon after the NYSE completes its clearance review at the end of July.
Risk factors	You should carefully read and consider the information beginning on page 15 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 common stock, 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.

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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, 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 three months ended March 31, 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 three months ended March 31, 2011 and the consolidated balance sheet data as of March 31, 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 March 31, 2011 gives effect to this offering and the repayment of indebtedness as if they had occurred on March 31, 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.

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	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]	Three Months Ended March 31, 2010 (unaudited)	Period from Inception (December 23, 2010) to December 31, 2010	Three Months Ended March 31, 2011 (unaudited)	Year Ended December 31, 2010 (unaudited)
	(in thousands, except per share data)						
Statement of Operations Data:							
Revenues:							
Oil sales	$ 39,967	$ 27,601	$ 34,431	$ 7,514	$ 1,325	$ 16,576	$ 45,413
Natural gas sales	5,165	3,671	6,226	1,663	207	2,926	10,253
Natural gas liquids and CO_2 sales	2,782	3,169	7,672	1,544	213	2,711	8,365
Total revenues	47,914	34,441	48,329	10,721	1,745	22,213	64,031
Operating expenses:							
Lease operating	20,434	13,449	14,792	3,434	483	4,614	17,285
Severance and ad valorem taxes	1,847	2,148	1,621	333	70	1,053	2,524
Depreciation, depletion and amortization	25,463	14,108	14,225	3,261	506	6,387	20,917
General and administrative	7,477	7,610	8,375	2,087	323	2,239	9,338
Employee stock compensation[3]							
Exploration	25	131	361	114		525	380
Impairment of oil and gas properties[4]	26,437	579					
Cancelled private placement[5]			2,378				2,378
Total operating expenses	81,683	38,025	41,752	9,229	1,382	14,818	52,822
Income (loss) from operations	(33,769)	(3,584)	6,577	1,492	363	7,395	11,209
Other income (expense):							
Interest expense	(12,870)	(16,582)	(18,001)	(3,959)	(58)	(713)	(1,263)
Amortization of debt discount	(5,987)	(7,963)	(8,862)	(2,127)			
Write off of deferred financing costs			(1,663)				(1,663)
Gain on sale of oil and gas properties	8	303	4,055	4,092			4,055
Unrealized gain (loss) in fair value of warrant put option[6]	70,972	(80,640)	34,345	(24,204)			
Unrealized gain (loss) in fair value of commodity derivatives	48,716	(34,589)	(7,605)	(1,142)	(514)	(5,455)	(8,119)
Realized gain on settled commodity derivatives	1,913	13,451	5,919	1,585	(47)	(776)	5,872
Other income (loss)	(229)	(179)	19	(60)		68	(47)
	102,523	(126,199)	8,207	(25,815)	(619)	(6,876)	(1,165)

Total other income (expense)							
Income (loss) before income taxes	68,754	(129,783)	14,784	(24,323)	(256)	519	10,044
Income tax benefit (expense)(7)					94	(192)	(3,696)
Net income (loss)	$ 68,754	$ (129,783)	$ 14,784	$ (24,323)	$ (162)	$ 327	$ 6,348
Net income per common share(8)							
Basic					$ (0.01)	$ 0.01	
Diluted					$ (0.01)	$ 0.01	
Weighted average shares outstanding							
Basic					29,123	29,123	
Diluted					29,123	29,123	

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(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.

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(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 the 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,				
	2008	2009	As of December 31, 2010	As of March 31, 2011	As of March 31, 2011 As Adjusted[1]
				(unaudited)	(unaudited)
			(in thousands)		
Balance Sheet Data:					
Cash and cash equivalents	$ 4,088	$ 2,522	$	$ 768	
Property and equipment, net	195,280	188,367	496,582	508,653	
Total assets	241,625	211,552	516,104	528,482	
Long term debt, including current portion:					
Credit facility	107,000	99,000	55,400	63,500	
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	356,707	

	Bonanza Creek Energy Company, LLC (Predecessor)				Bonanza Creek Energy, Inc.	
	Year Ended December 31,					
	2008	2009	Period Ended December 23, 2010[4]	Three Months Ended March 31, 2010	Period from Inception (December 23, 2010) to December 31, 2010	Three Months Ended March 31, 2011
				(unaudited)	(unaudited)	
			(in thousands)			
Other Financial Data:						
Net cash provided by operating activities	$ 11,128	$ 11,134	$ 22,759	$ 4,225	$ (1,633)	$ 8,535
Net cash provided by (used in) investing activities	(79,581)	(7,185)	(32,127)	5,697	(817)	(14,880)
	72,541	(5,515)	9,297	(9,153)		7,113

Net cash provided by (used in) financing activities						
Adjusted EBITDAX[5]	14,435	19,067	25,071	5,165	822	13,599

(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 unaudited period from inception (December 23, 2010) to December 24, 2010 through December 31, 2010 are included in the results presented above.

(5) 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 to net cash provided by (used in) operating activities, see "*Summary Reserve and Operations Data Non-GAAP Financial Measures and Reconciliation Adjusted EBITDAX*," below.

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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 2,798 MBoe and 9,333 MBoe, respectively, and a PV-10 value of $115.0 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 flows 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.

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	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, 2008	Year Ended December 31, 2009	Period Ended December 23, 2010[1]	Three Months Ended March 31, 2010	Period from Inception (December 23, 2010) to December 23, 2010	Three Months Ended March 31, 2011	Period Ended December 23, 2010[1]	Year Ended December 31, 2010
Net Sales Data:								
Crude oil (MBbls)	453.7	507.4	469.0	104.6	15.9	187.1	129.1	614.1
Natural gas (MMcf)	668.9	939.0	1,308.5	282.1	43.0	578.5	780.6	2,132.2
Natural gas liquids (MBbls)	35.5	69.1	126.5	23.1	3.3	46.3	8.7	138.4
CO_2 (MMcf)	663.0	217.1	533.1	186.3	18.3	18.3		537.6
Crude oil equivalent (MBoe)[3]	600.7	733.0	813.6	174.7	26.4	329.8	267.9	1,107.9
Average daily volumes (Boe/day)[3]	1,641	2,008	2,279	1,941	3,297	3,664	750	3,035
Average Sales Price (Before Hedging)[4]:								
Crude oil (per Bbl)	$ 88.09	$ 54.40	$ 73.41	$ 71.87	$ 83.24	$ 88.61	$ 74.78	$ 73.95
Natural gas (per Mcf)	7.72	3.91	4.76	5.90	4.80	5.06	4.89	4.81
Natural gas liquids (per Bbl)	57.45	41.77	56.04	57.73	63.42	58.15	55.46	56.18
CO_2 (per Mcf)	1.12	1.30	1.09	1.13	1.12	1.13		1.09
Average equivalent price (per Boe)[3]	78.53	46.60	58.69	60.18	65.98	67.30	52.10	57.27
Average Sales Price (After Hedging)[4]:								
Crude oil (per Bbl)	$ 79.59	$ 67.40	$ 75.07	$ 73.19	$ 81.18	$ 83.57	$ 74.78	$ 74.47
Natural gas (per Mcf)	7.93	5.05	5.01	6.37	4.48	5.35	4.89	5.16
Natural gas liquids (per Bbl)	57.45	41.77	56.04	57.73	63.42	58.15	55.46	56.18
CO_2 (per Mcf)	1.12	1.30	1.09	1.13	1.12	1.13		1.09
Average equivalent price (per Boe)[3]	72.35	57.07	60.05	61.74	64.21	64.95	52.10	58.22
Expenses (per Boe)[3]:								
Lease operating expenses	$ 34.02	$ 18.35	$ 18.18	$ 19.67	$ 18.31	$ 13.99	$ 7.50	$ 15.60
Severance and ad valorem taxes	3.07	2.93	1.99	1.91	2.65	3.19	3.11	2.28
General and administrative	12.45	10.38	13.22	11.95	12.27	6.79	2.37	10.58
Depreciation, depletion and amortization	42.39	19.25	17.48	18.67	19.20	19.37	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 rating agencies and is not a measure of net income or cash flows as determined by United States generally accepted accounting principles, or GAAP.

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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,		**Period Ended December 23, 2010[(1)]**	**Three Months Ended March 31, 2010**	**Period from Inception (December 23, 2010) to December 31, 2010**	**Three Months Ended March 31, 2011**
	2008	**2009**				
	(in thousands)					
Adjusted EBITDAX Reconciliation to Net Income (Loss):						
Net income (loss)	$ 68,754	$ (129,783)	$ 14,784	$ (24,323)	$ (162)	$ 327
Changes in unrealized (gain) loss on derivative instruments	(119,689)	115,229	(26,740)	25,346	514	5,455
Change in unrealized loss on derivative liability assumed	(5,403)	(5,439)	(4,407)	(1,227)		
Income taxes					(94)	192
Cancelled private placement			2,378			
(Gain) on sale of properties	(8)	(303)	(4,055)	(4,092)		
Accretion of debt discount	5,986	7,963	8,862	2,127		
Write off of deferred financing costs			1,663			
Interest expense	12,870	16,582	18,001	3,959	58	713
Depreciation, depletion and amortization	25,463	14,108	14,225	3,261	506	6,387
Impairment of oil and gas properties	26,437	579				
Exploration expenses	25	131	360	114		525
Adjusted EBITDAX	$ 14,435	$ 19,067	$ 25,071	$ 5,165	$ 822	$ 13,599

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	Bonanza Creek Energy Company, LLC (Predecessor)				Bonanza Creek Energy, Inc.	
	Year Ended December 31,					
	2008	2009	Period Ended December 23, 2010(1)	Three Months Ended March 31, 2010	Period from Inception (December 23, 2010) to December 31, 2010	Three Months Ended March 31, 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	$ 4,225	$ (1,633)	$ 8535
Cancelled private placement			2,378			
Cash interest expense	5,374	5,159	5,368	994	42	511
Cash exploration expenses	25	131	318	114		484
Other		(138)				
Provision for losses on accounts receivable	(343)					
Changes in working capital	(1,749)	2,781	(5,752)	(168)	2,413	4,069
Adjusted EBITDAX	$ 14,435	$ 19,067	$ 25,071	$ 5,165	$ 822	$ 13,599

(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 flows 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 37.5% federal and state income tax rate.

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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

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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, we currently have commodity price hedging agreements on approximately 48% of our Boe production. To the extent we are unhedged, 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

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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 December 31, 2010, 38,904 net acres of our properties in the Rocky Mountain region, specifically 8,480 acres in the DJ Basin and 30,424 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 7,284 net acres will expire in 2011, 3,076 net acres will expire in 2012 and 11,120 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

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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 $151.5 million with $135.3 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.

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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 field to our McKamie gas processing facility 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 field 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 field 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

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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 no 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 processing plant facility) 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.

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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 our 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

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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 and 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 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.

Among the changes contained in the President's Fiscal Year 2012 budget proposal, released by the White House on February 14, 2011, is the elimination or deferral of certain key U.S. federal income tax deductions currently available to oil and gas exploration and production companies. 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 can 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. The U.S. Department of the Interior is also considering disclosure requirements or other mandates for hydraulic fracturing on federal land, 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 ("GHGs") may be linked to climate change. Climate change and the costs that may be associated with its impacts and the regulation of GHGs 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 GHGs 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 GHGs. Among other things, the Agency is limiting emissions of greenhouse gases 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 greenhouse gas 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 greenhouse gas emissions in a multi-step process, with the largest sources first subject to permitting. Facilities required to obtain PSD permits for their greenhouse gas 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 greenhouse gas emissions from specified large greenhouse gas 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 greenhouse gases 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 GHGs, there currently is a great deal of uncertainty as to how and when additional federal regulation of GHGs 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 greenhouse gas 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 greenhouse gas 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 greenhouse gases could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. 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 greenhouse gases could have an adverse effect on our business, financial condition and results of operations.

Finally, it should be noted that some scientists have concluded that increasing concentrations of greenhouse gases in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms 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.

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*" 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.

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

Based on an assumed initial public offering price of $ per share, purchasers of our common stock in this offering will experience an immediate and substantial dilution of $ per share in the pro forma as adjusted net tangible book value per share of common stock from the initial public offering price, and our pro forma as adjusted net tangible book value as of March 31, 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; 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*," 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 plan. Subject to the satisfaction of vesting conditions and the expiration of lock-up agreements, shares registered under this registration statement on Form S-8 will be available for resale immediately in the public market without restriction.

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.

We expect to amend and restate our certificate of incorporation and bylaws immediately prior to the consummation of this offering. We expect that our amended and restated certificate of incorporation and bylaws will contain, and Delaware law contains, provisions that could enable our management to resist a takeover attempt. We may adopt provisions that would:

- permit us to issue, without any further vote or action by the stockholders, additional shares of preferred stock in one or more series and, with respect to each such series, to fix the number of

shares constituting the series and the designation of the series, the voting powers (if any) of the shares of the series, and the preferences and relative, participating, optional, and other special rights, if any, and any qualification, limitations or restrictions of the shares of such series;

- require special meetings of the stockholders to be called by the chairman of the board, the chief executive officer, the president, or by resolution of a majority of the board of directors;

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

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

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

- permit directors to fill vacancies in our board of directors.

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 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.

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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.

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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;

- 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.

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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 April 30, 2011, was approximately $68.4 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 March 2015 and bears interest at a variable rate, which was approximately 2.7% per annum as of April 30, 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.

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.

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CAPITALIZATION

The following table sets forth our capitalization, as of March 31, 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 March 31, 2011	
	Actual	**As Adjusted**
	(in thousands)	
Cash and cash equivalents[1]	$ 768	
Long-term debt:		
Credit facility[2]	$ 63,500	
Total long-term debt	63,500	
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, 7,500 shares issued and outstanding[3]		
Common stock, $0.001 par value; shares authorized; shares issued and outstanding		
Additional paid-in capital	356,513	
Retained earnings	165	
Total stockholders' equity	356,707	
Total capitalization	$ 420,207	

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(1) As of April 30, 2011, our cash and cash equivalents were $0.9 million.

(2) As of April 30, 2011, there was $68.4 million outstanding under our credit facility.

(3) As of May 20, 2011, following the resignation of Steve Black, 6,000 shares were issued and outstanding. On June 30, 2011, in connection with the commencement of his employment with us, Steven R. Enger, our Chief Financial Officer, was granted 600 shares of our Class B Common Stock.

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DILUTION

Purchasers of the common stock in this offering will experience immediate and substantial dilution in the net tangible book value per share of the common stock for accounting purposes. Our net tangible book value 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	$
Pro forma net tangible book value per share as of March 31, 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		%	$	%	$ %

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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, 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 three months ended March 31, 2010 are derived from the financial statements of BCEC appearing elsewhere in this prospectus, and the consolidated statement of operations data for the three months ended March 31, 2011 and the consolidated balance sheet data as of March 31, 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 March 31, 2011 gives effect to this offering and the repayment of indebtedness as if they had occurred on March 31, 2011.

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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]	Three Months Ended March 31, 2011	Period from Inception (December 23, 2010) to December 31, 2010	Three Months Ended March 31, 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	$ 7,514	$ 1,325	$ 16,576	$ 45,413
Natural gas sales	1,113	1,736	5,165	3,671	6,226	1,663	207	2,926	10,253
Natural gas liquids and CO_2 sales	391	821	2,782	3,169	7,672	1,544	213	2,711	8,365
Total revenues	5,646	13,984	47,914	34,441	48,329	10,721	1,745	22,213	64,031
Operating expenses:									
Lease operating	1,584	4,037	20,434	13,449	14,792	3,434	483	4,614	17,285
Severance and ad valorem taxes	325	577	1,847	2,148	1,621	333	70	1,053	2,524
Depreciation, depletion and amortization	1,796	4,237	25,463	14,108	14,225	3,261	506	6,387	20,917
General and administrative	2,096	4,752	7,477	7,610	8,375	2,087	323	2,239	9,338
Employee stock compensation[4]									
Exploration	40	65	25	131	361	114		525	380
Impairment of oil and gas properties[5]			26,437	579					
Cancelled private placement[6]					2,378				2,378
Total operating expenses	5,841	13,668	81,683	38,025	41,752	9,229	1,382	14,818	52,822
Income (loss) from operations	(195)	316	(33,769)	(3,584)	6,577	1,492	363	7,395	11,209
Other income (expense):									
Interest expense	(2,483)	(5,748)	(12,870)	(16,582)	(18,001)	(3,959)	(58)	(713)	(1,263)
Amortization of debt discount		(1,684)	(5,987)	(7,963)	(8,862)	(2,127)			
Write off of deferred financing costs					(1,663)				(1,663)
Gain on sale of oil and gas properties	1,000		8	303	4,055	4,092			4,055
Unrealized gain (loss) in fair value of warrant put option[7]		(32,302)	70,972	(80,640)	34,345	(24,204)			

Unrealized gain (loss) in fair value of commodity derivatives	356	(925)	48,716	(34,589)	(7,605)	(1,142)	(514)	(5,455)	(8,119)
Realized gain (loss) on settled commodity derivatives		26	1,913	13,451	5,919	1,585	(47)	(776)	5,872
Other income (loss)	11	(43)	(229)	(179)	19	(60)		68	(47)
Total other income (expense)	(1,116)	(40,676)	102,523	(126,199)	8,207	(25,815)	(619)	(6,876)	(1,165)
Income (loss) before income taxes	(1,311)	(40,360)	68,754	(129,783)	14,784	(24,323)	(256)	519	10,044
Income tax benefit (expense)[8]							94	192	3,696
Net income (loss)	$ (1,311)	$ (40,360)	$ 68,754	$ (129,783)	$ 14,784	$ (24,323)	$ (162)	$ 327	$ 6,348
Net income (loss) per common share[9]									
Basic							$ (0.01)	$ 0.01	
Diluted							$ (0.01)	$ 0.01	
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.

(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.*"

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(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 the 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 March 31, 2011 (unaudited)	As of March 31, 2011 As Adjusted[2] (unaudited)
	(in thousands)						
Balance Sheet Data:							
Cash and cash equivalents	$ 5,039	$	$ 4,088	$ 2,522	$	$ 768	
Property and equipment, net	52,103	89,646	195,280	188,367	496,582	508,653	
Total assets	62,317	97,044	241,625	211,552	516,104	528,482	
Long term debt, including current portion:							
Credit facility		27,274	107,000	99,000	55,400	63,500	
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	356,707	

	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]	Three Months Ended March 31, 2011 (unaudited)	Period from Inception (December 23, 2010) to December 31, 2010	Three Months Ended March 31, 2011 (unaudited)
	(in thousands)							
Other Financial Data:								
Net cash provided by (used in) operating activities	$ 3,764	$ (561)	$ 11,128	$ 11,134	$ 22,759	$ 4,225	$ (1,633)	$ 8,535
Net cash provided by (used in) investing activities	(21,739)	(43,265)	(79,581)	(7,185)	(32,127)	5,697	(817)	(14,880)

Net cash provided by (used in) financing activities	23,014	38,787	72,541	(5,515)	9,297	(9,153)		7,113
Adjusted EBITDAX[(6)]	1,653	4,537	14,435	19,067	25,071	5,165	822	13,599

(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) Warrants and the aggregate warrant exercise price were exchanged for shares of our common shares 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.

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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 the 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 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.

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	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

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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%.

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with 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 the members of BCEC 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 $135.3 million in 2011 to drill 129 gross (114.6 net) wells, to perform workovers on 43 gross (33.8 net) wells and to make other improvements to our infrastructure.

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.

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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 and certain of its members. 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 9,333 MBoe at December 31, 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. 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 testing our extensive inventory of horizontal Niobrara oil shale potential located in Colorado.

Our total 2011 capital expenditure budget is approximately $151.5 million, exclusive of acquisitions, which consists of:

- $135.3 million for development of our oil and gas properties; and
- $16.2 million for the construction of an additional gas processing facility.

We expect to drill 129 gross (114.6 net) wells in 2011, including 42 gross (33.4 net) infill PUD locations in southern Arkansas, 66 gross (62.3 net) wells in the DJ Basin, 7 gross (7.0 net) Niobrara oil shale wells in the North Park Basin, 4 gross (3.8 net) Niobrara oil shale wells in the DJ Basin and 10 gross (8.0 net) wells in California. At April 30, 2011, we had drilled 33 gross (29.7 net) of these wells, including 13 gross (10.2 net) wells in southern Arkansas, 19 gross (19 net) wells in the DJ and North Park Basins and 1 gross (0.5 net) wells in California. While we estimate we will spend $135.3 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 estimate we will spend approximately $16.2 million to build a 12.5 MMcf/d processing facility in our Dorcheat Macedonia field. Construction is under way, and we expect to have the site completed during August of this year. The construction of this new facility is in conjunction with our continued development of the field and is on track with our development timing. Our McKamie facility currently processes all of the natural gas that we produce from the Dorcheat and McKamie 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 March 31, 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 quarter of 2010. Our average unhedged sales price for crude oil for the first quarter of 2011 was $88.61 per barrel, compared to $71.87 per barrel for the first quarter of 2010, which price increase, along with a 79% increase in crude oil sales volumes, contributed to the 121% 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 three months ended March 31, 2011 have increased by 89% compared to the three months ended March 31, 2010 as a result of the HEC acquisition. To further increase our production, we expect to spend approximately $135.3 million in 2011 to drill 129 gross (114.6 net) wells, to perform workovers on 43 gross (33.8 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 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 three months ended March 31, 2011 have increased by 7% compared to the three months ended March 31, 2010 as a result of the HEC acquisition in December 2010. We estimate 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, 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 207,083 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 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 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 April 30, 2011, we had approximately $68.4 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.

Three Months Ended March 31, 2011 Compared to Three Months Ended March 31, 2010

Revenues

	Three Months Ended March 31,			
	2010	2011	Change	Percent Change
	(In thousands, except percentages)			
Revenues:				
Crude oil sales	$ 7,514	$ 16,576	$ 9,062	121 %
Natural gas sales	1,663	2,926	1,263	76 %
Natural gas liquids sales	1,333	2,690	1,357	102 %
CO_2 sales	211	21	(190)	(90)%
Product revenues	$ 10,721	$ 22,213	$ 11,492	107 %

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	Three Months Ended March 31,			
	2010	2011	Change	Percent Change
Sales volumes:				
Crude oil (MBbls)	104.6	187.1	82.5	79%
Natural gas (MMcf)	282.1	578.5	296.4	105%
Natural gas liquids (MBbls)	23.1	46.3	23.2	100%
Crude oil equivalent (MBoe)(1)	174.7	329.8	155.1	89%

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

	Three Months Ended March 31,			
	2010	2011	Change	Percent Change
Average Sales Prices (before hedging)(1):				
Crude oil (per Bbl)	$ 71.87	$ 88.61	$ 16.74	23 %
Natural gas (per Mcf)	5.90	5.06	(0.84)	(14)%
Natural gas liquids (per Bbl)	57.73	58.15	0.42	1 %
Crude oil equivalent (per Boe)(2)	60.18	67.30	7.12	12 %

	Three Months Ended March 31,			
	2010	2011	Change	Percent Change
Average Sales Prices (after hedging)(1):				
Crude oil (per Bbl)	$ 73.19	$ 83.57	$ 10.38	14 %
Natural gas (per Mcf)	6.37	5.35	(1.02)	(16)%
Natural gas liquids (per Bbl)	57.73	58.15	0.42	1 %
Crude oil equivalent (per Boe)(2)	61.74	64.95	3.21	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.

Revenues increased by 107%, to $22.2 million for the three months ended March 31, 2011 compared to $10.7 million for the three months ended March 31, 2010. Oil production increased 79% and natural gas production increased 105% during the three months ended March 31, 2011 as compared to the three months ended March 31, 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 for the three months ended March 31, 2010 exclude product revenues for HEC of $3.5 million. The increase in net revenues was the result of a 23% increase in oil prices offset by a 14% decrease in natural gas prices, respectively, for an overall increase of 12% per Boe. Also contributing to the increased revenue was the increased production attributable to our drilling program.

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Operating Expenses

	Three Months Ended March 31,			
	2010	2011	Change	Percent Change
	(In thousands, except percentages)			
Expenses:				
Lease operating	$ 3,434	$ 4,614	$ 1,180	34%
Severance and ad valorem taxes	333	1,053	720	216%
General and administrative	2,087	2,239	152	7%
Depreciation, depletion and amortization	3,261	6,387	3,126	96%
Exploration	114	525	411	361%
Operating expenses	$ 9,229	$ 14,818	$ 5,589	61%

	Three Months Ended March 31,			
	2010	2011	Change	Percent Change
Selected Costs ($ per Boe):				
Lease operating	$ 19.67	$ 13.99	$ (5.68)	(29)%
Severance and ad valorem taxes	1.91	3.19	1.28	67 %
General and administrative	11.95	6.79	(5.16)	(43)%
Depreciation, depletion and amortization	18.67	19.37	0.70	4 %
Exploration	0.65	1.59	0.94	145 %
Operating expenses	$ 52.85	$ 44.93	$ (7.92)	(15)%

Lease operating expenses. Our lease operating expenses increased $1.2 million, or 34%, to $4.6 million in the first three months of 2011 from $3.4 million in the first three months of 2010 and decreased on an equivalent basis from $19.67 per Boe to $13.99 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 three months ended March 31, 2010 does not include HEC lease operating expenses, which were $0.5 million. During the three months ended March 31, 2011, workover activity and steam gas costs were $0.6 million and $0.1 million, higher, respectively, than the three months ended March 31, 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 $8.73 per Boe during the three months ended March 31, 2010 as compared to the lease operating expense for our wells which was $19.67 per Boe during the three months ended March 31, 2010.

Severance and ad valorem taxes. Our severance and ad valorem taxes increased $0.7 million, or 216%, to $1.1 million in the first three months of 2011 from $0.3 million in the first three months of 2010 and increased on a Boe basis from $1.91 to $3.19. The increase was primarily related to an 89% increase in production volumes and a 10% increase in realized prices per Boe during the three months ended March 31, 2011 as compared to the three months ended March 31, 2010, and an increase in ad valorem tax of $0.3 million due to higher assessment values. The three months ended March 31, 2010 does not include HEC severance and ad valorem tax, which were $0.2 million. The increase in severance and ad valorem taxes on a Boe basis for the three months ended March 31, 2011 as compared to the three months ended March 31, 2010 was primarily related to higher ad valorem tax of $0.3 million.

General and administrative. Our general and administrative expense increased $0.1 million, or 7%, to $2.2 million in the first three months of 2011 from $2.1 million in the first three months of 2010. The three months ended March 31, 2010 does not include HEC general and administrative expenses, which were

$0.2 million. The increase in general and administrative expenses on an equivalent basis was primarily related to the acquisition of HEC, which added significant production with lower related general and administrative expenses.

Depreciation, depletion and amortization. Our depreciation, depletion and amortization expense increased $3.1 million, or 96%, to $6.4 million in the first three months of 2011 from $3.3 million in the three months ended March 31, 2010. This increase was the result of an 89% increase in production. Our depreciation, depletion and amortization expense per Boe produced increased by $0.70, or 4%, to $19.37 for the three months ended March 31, 2011 as compared to $18.67 for the three months ended March 31, 2010. Another component of the increase was the step up in basis that was recorded in oil and gas properties as a result of the Corporate Restructuring. In connection with the 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 region fields.

Exploration. Our exploration expense increased $0.4 million, or 361%, to $0.5 million in the three months ended March 31, 2011 from $0.1 million in the first three months of 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.

Other Income and Expense

Interest expense. Our interest expense decreased $3.3 million, or 82%, to $0.7 million in the three months ended March 31, 2011 from $4.0 million in the first three months of 2010. The decrease resulted from the application of $182 million of cash proceeds from the 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 three months ended March 31, 2011 was $59.5 million as compared to $202.8 million for the three months ended March 31, 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 three months ended March 31, 2011 from $4.1 million in the first three months of 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 $2.4 million from a gain of $1.6 million for the three months ended March 31, 2010 to a loss of $0.8 million for the three months ended March 31, 2011. Because we assumed a derivative in a liability position in 2008, our realized gain was higher by $1.3 million upon the settlement of this portion of the assumed derivative in the three months ended March 31, 2010. The decrease in realized cash hedge gains period over period was primarily related to commodity prices that were 10% higher during the three months ended March 31, 2011 as compared to the three months ended March 31, 2010.

Income Tax Expense. Our predecessor, BCEC, was not subject to federal and state income taxes. As a result of the Corporate Restructuring, we were organized as a Delaware corporation subject to federal and state income taxes. Accordingly, we incurred $0.2 million in federal and state income taxes for the three months ended March 31, 2011. Income taxes are recorded at the combined federal and state effective rate of 36.87% for the period ended March 31, 2011. 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 March 31, 2011 were deferred.

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Change in fair value of warrant put option. The unrealized loss from the change in the fair value of the warrant put option decreased $24.2 million, or 100%, to $0 for the three months ended March 31, 2011 from $24.2 million for the three months ended March 31, 2010. The decrease resulted from the exercise of the warrants on December 23, 2010 in connection with our Corporate Restructuring.

Accretion of debt discount. Our expense for accretion of debt discount decreased $2.1 million, or 100%, to $0 for the three months ended March 31, 2011 from $2.1 million for the three months ended March 31, 2010. The decrease resulted from the retirement of BCEC's senior subordinated notes on December 23, 2010 in connection with our Corporate Restructuring.

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

We completed our Corporate Restructuring on December 23, 2010. Our 2010 results are based on combining the operating results of BCEI for the audited period from inception (December 23, 2010) to December 24, 2010 through December 31, 2010 and the operating results of our predecessor, BCEC, for the audited period from January 1, 2010 through December 23, 2010.

	Bonanza Creek Energy Company, LLC Period Ended December 23, 2010	Bonanza Creek Energy, Inc. Period from Inception (December 23, 2010) to December 31, 2010	Total Year Ended December 31, 2010 (unaudited)
Revenues:			
Oil sales	$ 34,431	$ 1,325	$ 35,756
Natural gas sales	6,226	207	6,433
Natural gas liquids and CO2 sales	7,672	213	7,885
Total revenues	$ 48,329	$ 1,745	$ 50,074
Operating expenses:			
Lease operating	14,792	483	15,275
Severance and ad valorem taxes	1,621	70	1,691
Exploration	361		361
Depreciation, depletion and amortization(1)	14,225	506	14,731
General and administrative	8,375	323	8,698
Cancelled private placement	2,378		2,378
Total operating expenses	41,752	1,382	43,134
Income from operations	6,577	363	6,940
Other income (expense):			
Gain on sale of oil and gas properties	4,055		4,055
Other income (loss)	19		19
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)	(58)	(18,059)
Total other income (expense)	8,207	(619)	7,588