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	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	$ 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	

(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,				**As of March 31, 2011 As Adjusted[1]**
	2008	**2009**	**As of December 31, 2010**	**As of March 31, 2011**	
				(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,		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 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 As of December 31,	Bonanza Creek Energy, Inc. Pro Forma 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.

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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 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

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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

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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

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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;

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- 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	

(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.**		
		As of December 31,					
	Inception to December 31, 2006[1]	**2007**	**2008**	**2009**	**As of December 31, 2010**	**As of March 31, 2011**	**As of March 31, 2011 As Adjusted[2]**
						(unaudited)	**(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.**	
		Year Ended December 31,						
	Inception to December 31, 2006[1]	**2007**	**2008**	**2009**	**Period Ended December 23, 2010[5]**	**Three Months Ended March 31, 2011**	**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 (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.

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

Income before income taxes	$ 14,784	$ (256)	$ 14,528

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Revenues

	Year Ended December 31, 2009	2010	Change	Percent Change
	(In thousands, except percentages)			
Revenues:				
Crude oil sales	$ 27,601	$ 35,756	$ 8,155	30%
Natural gas sales	3,671	6,433	2,762	75%
Natural gas liquids sales	2,886	7,297	4,411	153%
CO_2 sales	283	588	305	108%
Product revenues	$ 34,441	$ 50,074	$ 15,633	45%

	Year Ended December 31, 2009	2010	Change	Percent Change
Sales Volumes:				
Crude oil (MBbls)	507.4	484.9	(22.5)	(4)%
Natural gas (MMcf)	939.0	1,351.5	412.5	44 %
Natural gas liquids (MBbls)	69.1	129.8	60.7	88 %
Crude oil equivalent (MBoe)(1)	733.0	840.0	107.0	15 %

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

	Year Ended December 31, 2009	2010	Change	Percent Change
Average Sales Prices (before hedging)[(1)]:				
Crude oil (per Bbl)	$ 54.40	$ 73.73	$ 19.33	36%
Natural gas (per Mcf)	3.91	4.76	0.85	22%
Natural gas liquids (per Bbl)	41.77	56.23	14.46	35%
Crude oil equivalent (per Boe)[(2)]	46.60	58.91	12.31	26%

	Year Ended December 31, 2009	2010	Change	Percent Change
Average Sales Prices (after hedging)[(1)]:				
Crude oil (per Bbl)	$ 67.40	$ 75.27	$ 7.87	12%
Natural gas (per Mcf)	5.05	4.99	(0.06)	(1)%
Natural gas liquids (per Bbl)	41.77	56.23	14.46	35%
Crude oil equivalent (per Boe)[(2)]	57.07	60.18	3.11	5%

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

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

Product revenues increased by 45%, to $50 million in 2010 compared to $34 million in 2009. The increase in product revenues was primarily due to higher average prices for oil, natural gas and natural gas liquids in 2010 as compared to 2009 of 36%, 22% and 35%, respectively, and higher natural gas and natural gas liquids production in 2010 as compared to 2009 of 44% and 88%, respectively. Production

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

Operating Expenses

	Year Ended December 31,			
	2009	2010	Change	Percent Change
	(In thousands, except percentages)			
Expenses:				
Lease operating	$ 13,449	$ 15,275	$ 1,826	14 %
Severance and ad valorem taxes	2,148	1,691	(457)	(21)%
General and administrative	7,610	8,698	1,088	14 %
Depreciation, depletion and amortization	14,108	14,731	623	4 %
Exploration	131	361	230	176 %
Impairment of oil and gas properties	579		(579)	(100)%
Cancelled private placement		2,378	2,378	100 %
Operating expenses	$ 38,025	$ 43,134	$ 5,109	13 %

	Year Ended December 31,			
	2009	2010	Change	Percent Change
Selected Costs ($ per Boe):				
Lease operating	$ 18.35	$ 18.19	$ (.16)	(1)%
Severance and ad valorem taxes	2.93	2.01	(.92)	(31)%
General and administrative	10.38	10.36	(0.2)	%
Depreciation, depletion and amortization	19.25	17.54	(1.71)	(9)%
Exploration	0.18	0.43	0.25	139 %
Impairment of oil and gas properties	0.79		(.79)	(100)%
Cancelled private placement		2.83	2.83	100 %
Operating expenses	$ 51.88	$ 51.36	$ (0.52)	(1)%

Lease operating expenses. Our lease operating expenses increased $1.8 million, or 14%, to $15.3 million in 2010 from $13.4 million in 2009. The increase in lease operating expenses was primarily related to higher compression rental costs in our Dorcheat Macedonia field, increased workover activity and higher steam injection expense related to our California thermal properties.

Severance and ad valorem taxes. Severance and ad valorem taxes per Boe decreased by $0.92, or 31%, to $2.01 for 2010 from $2.93 for 2009. The decrease in production taxes was due primarily to refunds received from Colorado for overpayment of severance taxes in 2008 and 2009.

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General and administrative. Our general and administrative expenses increased $1.1 million, or 14%, to $8.7 million for 2010 from $7.6 million for 2009. The increase in general and administrative expenses was due primarily to an aggregate bonus of $0.5 million awarded to employees in connection with our Corporate Restructuring in December 2010.

Depreciation, depletion and amortization. Our depreciation, depletion and amortization expense increased $0.6 million, or 4%, to $14.7 million in 2010 from $14.1 million in 2009. Our depreciation, depletion and amortization expense per Boe produced decreased by $1.71, or 9%, to $17.54 for 2010 as compared to $19.25 for 2009 due primarily to additional reserves resulting from higher commodity prices in 2010 and reserves adds from workover and behind-pipe activities.

Other Income and Expense

Interest expense. Our interest expense increased $1.5 million, or 9%, to $18.1 million in 2010 from $16.6 million in 2009. As a result of $30 million in borrowings on a second lien note at a 14% rate, we paid down our first lien revolver at an annual rate of approximately 4%.

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

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

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

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

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

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

Revenues

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

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

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

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

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

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

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

Revenues decreased by 28%, to $3.4 million, in 2009 compared to $48 million in 2008. The decrease in net revenues was primarily due to significantly lower average oil and natural gas prices in 2009. The 42% increase in natural gas liquids revenues was the result of increased volumes of natural gas liquids as a result of our acquisition of producing properties in southern Arkansas in April 2008. For 2009, sales volumes increased approximately 23% compared to 2008. The increase in sales volumes was primarily due to our acquisition of producing properties in southern Arkansas in April 2008 and the increase in drilling activity subsequent to the acquisition.

Operating Expenses

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

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

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

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

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

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

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Other Income and Expense

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

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

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

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

Liquidity and Capital Resources

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

On March 29, 2011, we entered into $300 million senior secured revolving credit facility to provide us with additional liquidity and flexibility for capital expenditures. As of March 31, 2011, we had $63.5 million of indebtedness outstanding and $66.5 million of borrowing capacity available under our credit facility. We intend to use a portion of the proceeds from this offering to pay down all of the debt outstanding under our credit facility. Upon completion of this offering, we expect to have the full $130 million of borrowing base capacity available under our credit facility. The size of our borrowing base is at the discretion of the lenders under our credit facility and is dependent upon a number of factors, including commodity prices and reserve levels. For a summary of the material provisions of our credit facility, see " *Credit facility*."

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

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

	Year Ended December 31,			Three Months Ended March 31,	
	2008	2009	2010	2010	2011
			(in thousands)		
Financial Measures:					
Net cash provided by operating activities	$ 11,128	$ 11,134	$ 21,726	$ 4,225	$ 8,535
Net cash provided by (used in) investing activities	(79,581)	(7,185)	(32,944)	5,697	(14,880)
Net cash provided by (used in) financing activities	72,541	(5,515)	9,297	(9,153)	7,113
Cash and cash equivalents	4,088	2,522		3,290	768
Acquisitions of oil and gas properties	40,846	650	1,066		
Exploration and development of oil and gas properties and gas processing facility	38,384	6,612	35,545	1,818	15,756

Cash flows provided by operating activities

Net cash provided by operating activities was $8.5 million for the three months ended March 31, 2011, compared to $4.2 million provided by operating activities for the three months ended March 31, 2010. The increase in operating activities resulted primarily from an increase in revenues, increased production, and increased commodity prices offset by cash utilized in connection with changes in working capital when comparing the periods. Cash utilized by changes in working capital for the three months ended March 31, 2011 was $4.0 million as compared to $0.2 million that was provided by changes in working capital for the comparable period during 2010. Increases in working capital of $4.0 million for the three months ended March 31, 2011 is comprised primarily of increases in oil and gas equipment inventory and prepaid expenses of $1.7 million and $0.3 million, respectively, related to increased activities, and a decrease in trade payables and accrued expenses (exclusive of capital accruals) of $1.1 million due primarily to timing of A/P check distributions.

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

Cash flows provided by (used in) investing activities

Expenditures for development of oil and natural gas properties are the primary use of our capital resources. Net cash used in investing activities for the three months ended March 31, 2011 was $14.9 million, compared to $5.7 million cash provided by investing activities for the three months ended March 31, 2010. Net cash provided by investing activities for the three months ended March 31, 2010 was primarily the results of the sale of our interest in the Jasmin field in California. Our primary use of net cash was approximately $1.8 million spent for development activity. For the year ended December 31, 2010, excluding the Corporate Restructuring, net cash used in investing activities was $32.9 million, of which we spent approximately $1.1 million on acquisitions, $35.5 million for the exploration and development of oil and gas properties, advanced $3.7 million to fund HEC's exploration and development program, offset by the receipt of proceeds in the amount of $7.5 million for the sale of the Jasmin field. In connection with the Corporate Restructuring, $59 million in cash along with common stock valued at $21.1 million was used to acquire HEC. For the year ended December 31, 2009, net cash used in investing activities was $7.2 million, of which we spent approximately $0.7 million for the acquisition of oil and gas properties and $6.6 million for the exploration and development of oil and gas properties. For the year ended December 31, 2008, net cash used in investing activities was $79.6 million, of which we spent approximately $41 million in cash on the acquisition of properties in southern Arkansas and the remainder on developing our proved reserves.

Cash flows provided by (used in) financing activities

Net cash flow provided by financing activities for the three months ended March 31, 2011 was $7.1 million primarily related to net borrowings on our line of credit in the amount of $8.1 million offset by deferred financing costs of approximately $1.0 million. Net cash used in financing activities for the three months ended March 31, 2010 was $9.2 million and was primarily related to debt payments on our credit facility. Net cash provided by financing, excluding Corporate Restructuring, was $9.3 million for the year ended December 31, 2010, primarily related to net borrowings in the amount of $12.7 million offset by deferred financing charges in the amount of $3.4 million. Net cash used in financing activities was $5.5 million for the year ended December 31, 2009, primarily the result of making debt payments on our credit facility. Net cash provided by financing activities was $72.5 million for the year ended December 31, 2008 was primarily the result of increases in borrowings under our credit facility to fund development activities and issuing subordinated debt to acquire our properties in southern Arkansas.

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

Credit facility

On March 29, 2011, we entered into a credit agreement providing for a $300 million senior secured revolving credit facility with an initial borrowing base of $130 million and with a $5 million subfacility for standby letters of credit. This credit facility is guaranteed by all of our subsidiaries.

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

We intend to use the net proceeds from this offering to repay all outstanding indebtedness under our credit facility, leaving us approximately $130 million available for future borrowings. As of April 30, 2011, we had approximately $68.4 million outstanding under our credit facility. The credit facility matures on March 29, 2015. Amounts borrowed and repaid under the credit facility may be reborrowed. The credit facility may be used only to finance development of oil and gas properties, for working capital and for other general corporate purposes.

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

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

- the London interbank offered rate, or LIBOR, for an elected interest period plus an applicable margin between 2.00% to 3.00%; or
- an alternate base rate (being the highest of the administrative agent's prime rate, the federal funds effective rate plus 0.5% or 3-month LIBOR plus 1.00%) plus an applicable margin between 1.00% and 2.00%.

The applicable margin varies on a daily basis based on the percentage outstanding under the borrowing base. We incur quarterly commitment fees based on the unused amount of the borrowing base of 0.5% per annum. We may prepay loans under the credit facility at any time without premium or penalty (other than customary LIBOR breakage costs).

The credit facility contains various covenants limiting our ability to:

- grant or assume liens;
- incur or assume indebtedness;
- grant negative pledges or agree to restrict dividends or distributions from subsidiaries;
- sell, transfer, assign or convey assets, or engage in certain mergers or acquisitions;
- make certain distributions;
- make certain loans, advances and investments;
- engage in transactions with affiliates;
- enter into sale and leaseback, take-or-pay or hydrocarbon prepayment transactions; or
- enter into certain swap agreements.

The credit facility also contains covenants requiring us to maintain:

- a current ratio of not less than 1.0 to 1.0; and
- a debt to EBITDAX coverage ratio of not more than: 4.00 to 1.00 as of the quarter ending March 31, 2011 (using EBITDAX for the quarter then ended multiplied by four); 4.00 to 1.00 as of the quarter ending June 30, 2011 (using EBITDAX for the two quarters then ending multiplied by two); 4.00 to 1.00 as of the quarter ending September 30, 2011 (using EBITDAX for the three quarters then ending multiplied by $^4/_3$); and 4.00 to 1.00 as of the quarter ending December 31, 2011 and each quarter thereafter (using the trailing four-quarter EBITDAX).

As of the three months ended March 31, 2011, we were in compliance with these ratios.

The credit agreement contains customary events of default, including:

- failure to pay any principal, interest, fees, expenses or other amounts when due;
- the failure of any representation or warranty to be materially true and correct when made;

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

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

bankruptcy or insolvency;

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

certain ERISA events involving us or our subsidiaries; and

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

Future capital requirements

We believe that the proceeds from this offering and our internally generated cash flow combined with access to our credit facility will be sufficient to meet the liquidity requirements necessary to fund our daily operations, planned capital development and execute on our growth strategy and debt service requirements. Any decision regarding a future financing transaction, and our ability to complete such a transaction, will depend on prevailing market conditions and other factors. Our ability to continue to meet our liquidity requirements and execute on our growth strategy can be impacted by economic conditions outside of our control, such as the recent disruption in the capital and credit markets, as well as commodity price volatility, which could, among other things, lead to a decline in the borrowing base under our credit facility in connection with a borrowing base redetermination. In such case, we may be required to seek other sources of capital earlier than anticipated, although the restrictions in our credit agreements may impair our ability to access other sources of capital, and access to additional capital may not be available on terms acceptable to us or at all.

Contractual Obligations

We have the following contractual obligations and commitments as of March 31, 2011 (in thousands):

	Total	1 Year or Less	2-3 Years	4-5 Years	More Than 5 Years
Credit facility[(1)]	$ 63,500			$ 63,500	$
Operating leases[(2)]	2,309	410	885	931	83
Asset retirement obligations[(3)]	6,112	400	400		5,312
	$ 71,921	$ 810	$ 1,285	$ 64,431	$ 5,395

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

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

(3) Amount represents our estimate of future retirement obligations on a discounted basis unless otherwise noted. Because these costs typically extend many years into the future, management prepares estimates and makes judgments that are subject to future revisions based upon numerous factors. The $0.4 million included in the one year or less category is not discounted and is included in accounts payable and accrued expenses as of March 31, 2011.

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Summary of Estimated Capital Expenditures

The following table summarizes our historical 2010 and our estimated 2011 capital expenditures. Our historical 2010 capital expenditures include 2010 expenditures made by HEC, which was acquired in December 2010. We routinely monitor and adjust our estimated capital expenditures in response to changes in oil and natural gas prices, availability of financing, drilling and acquisition costs, industry conditions, the timing of regulatory approvals, the availability of rigs, success or lack of success in drilling activities, contractual obligations, internally generated cash flows and other factors both within and outside our control. See "*Risk Factors Risks Related to the Oil and Natural Gas Industry and Our Business*." We do not budget for acquisitions.

Operation	Historical and Projected Capital Expenditures Years Ended December 31, 2010	2011
	(dollars in thousands)	
Oil and gas property development	$ 44,576	$ 135,363
Gas processing facility and other	4,491	16,150
Total	$ 49,067	$ 151,513

Off-Balance Sheet Arrangements

As of March 31, 2011, we had no material off-balance sheet arrangements. We have no plans to enter into any off-balance sheet arrangements in the foreseeable future.

Critical Accounting Policies

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

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

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

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

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

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

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

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

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

Recently Issued Accounting Pronouncements

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

Oil and Gas Reporting Requirements. In December 2008, the SEC released the final rule, "Modernization of Oil and Gas Reporting," which adopts revisions to the SEC's oil and gas reporting disclosure requirements. The disclosure requirements under this final rule require reporting of oil and gas reserves using the unweighted arithmetic average of the first-day-of-the-month price for the preceding twelve months rather than year-end prices, and the use of new technologies to determine proved reserves if those technologies have been demonstrated to result in reliable conclusions about reserves volumes. Companies are required to report the independence and qualifications of their reserves preparer or auditor and file reports when a third party is relied upon to prepare reserves estimates or conduct a reserves audit. In January 2010, the FASB issued authoritative guidance on oil and gas reserve estimation and disclosure, aligning their requirements with the SEC's final rule. We have presented and applied this new guidance for the year ended December 31, 2009 herein.

Inflation

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

Quantitative and Qualitative Disclosures on Market Risks

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

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

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

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

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

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

Settlement Period	Derivative Instrument	Total Notional Amount (Bbl/Mmbtu)	Average Floor Price	Average Ceiling Price	Fair Market Value of Asset (Liability)
					(In thousands)
Oil					
2010	Collar	358,528	$ 83.86	$ 133.43	$ (276)
	Swap	94,144	63.36	63.36	(4,094)
2011	Collar	167,472	90.00	123.00	(52)
	Swap	116,708	63.03	63.03	(5,017)
2012	Collar	50,616	90.00	123.00	54
	Swap	75,417	61.50	61.50	(3,090)
Gas					
2010	Swap	163,846	7.10	7.10	414
2011	Swap	202,319	6.75	6.75	342
2012	Swap	154,806	6.40	6.40	159
					$ (11,560)

Interest Rates. We intend to use the net proceeds from this offering to repay all outstanding indebtedness under our credit facility. At April 30, 2011, we had $68.4 million outstanding under our credit facility, which is subject to floating market rates of interest. Borrowings under our credit facility bear interest at a fluctuating rate that is tied to an adjusted base rate or LIBOR, at our option. Any increases in these interest rates can have an adverse impact on our results of operations and cash flow. Based on borrowings outstanding at April 30, 2011, a 100 basis point change in interest rates would change our annualized interest expense by approximately $0.7 million.

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

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

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BUSINESS

Overview

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

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

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

Our average net daily production rate during 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 prices for each of the preceding twelve months which were $79.43 per Bbl of crude oil and an average price of $4.38 per MMBtu of natural gas. Adjustments were

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

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

(3)
Projected capital expenditures for our Mid-Continent region include 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 $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 of 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.

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Our Business Strategies

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

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

Test and Evaluate Our Niobrara Oil Shale Acreage. We hold approximately 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 the first of which was commenced in June 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 involving the Niobrara formation in these counties have made this area one of the most active oil shale plays in the United States. While most of our acreage in the area is currently undeveloped, continued successful drilling of horizontal Niobrara wells by us or other operators could lead to development of that acreage over time. Prior to 2009, there were 11 horizontal wells in Weld County. In 2009, spud notices were issued for 6 horizontal wells which increased to 118 horizontal wells in 2010. As of June 2011, there were 72 spud notices received so far for 2011 and 309 permits issued for horizontal wells. 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

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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 geologically similar to our acreage position based on electric and porosity log response. The average initial 30-day production rate for these wells is 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. Additionally, since oil and gas production has been established, gathering systems are in place in this region, enabling a short time period from well completion to first product sales.

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

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

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

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

Gas Processing Capability in Southern Arkansas. The processing of our natural gas at our McKamie facility improves our well development economics in southern Arkansas. 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.

Bonanza Creek Acquisition History

Acquiring properties that are complementary to our existing positions or that have significant undeveloped resource potential has been an important part of our growth strategy. The following describes

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some of the recent acquisitions we have made to build our current position in the Mid-Continent, the Rocky Mountain and California regions:

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

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

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

Our Operations

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

Mid-Continent Region

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

Dorcheat Macedonia

In the Dorcheat Macedonia field we average a 83.3% working interest and 68.5% net revenue interest, and all of our acreage is held by production. We have approximately 78 gross (65.0 net) producing wells and our average net daily production during April 2011 was approximately 1,249 Boe/d from a proved reserves base of 15,247 MBoe, of which about 64.5% is oil and natural gas liquids. Productive reservoirs range in depth from 4,500 to 9,000 feet in depth. Those reservoirs have included the Smackover, Cotton Valley and the Pettet. Our primary development target is the Cotton Valley.

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

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

As of December 31, 2010, we have identified approximately 179 gross (142.6 net) PUD drilling locations on our acreage in this area. Currently, we have budgeted for 2011 capital expenditures of $53.5 million for the development of our Dorcheat Macedonia acreage. Under this budget we expect to drill 40 gross (31.4 net) additional infill PUD locations in the field this year. We expect to drill vertically to an average depth of approximately 8,700 feet for each location with a total expected drill and complete cost per well of approximately $1.7 million, approximately $1.6 million of which will be for initial drilling and completion. Typically, these wells take an average of 12 days to drill and three days to complete. The average initial 30-day production rate for the 24 wells we drilled in the Dorcheat Macedonia field and had on production since October 2009 was 146 Boe/d. Our typical well has a hyperbolic decline rate and an average economic life of 22 years. As of April 30, 2011, we have drilled 13 gross (10.2 net) of the planned 2011 wells.

Immediately northwest of the Dorcheat Macedonia field, we own and operate the McKamie gas processing facility, which processes all of the gas from the field. Natural gas is sold to the facility under a percent-of-proceeds contract whereby the field receives revenue from both gas and natural gas liquids sales after processing. Oil production is trucked from individual tank batteries.

Other Mid-Continent

We own additional interests in the Mid-Continent region near the Dorcheat Macedonia field. These include interests in the McKamie-Patton, Atlanta and Beach Creek fields. Our estimated proved reserves in these fields as of December 31, 2010 were approximately 1,947.8 MBoe, and average net daily production during April 2011 was approximately 239 Boe/d. We plan to drill 2 gross (2.0 net) wells in the McKamie-Patton field in 2011 at a cost of $1.2 million per well.

Gas Processing Facilities

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

The McKamie processing facility had an average net output of 749 Boe/d based on the facility contracts for the month of April, 2011. Our ownership of this facility and pipeline system provides us with the benefit of controlling processing and compression of our natural gas production and timing of connection to our newly completed wells. While we own the majority of the gas entering the facility, we also process some third-party natural gas through the system. Neither the revenue nor volumes of this third-party natural gas is included in our reserve reports.

In order to accommodate future increased gas volumes, we plan to invest $16.2 million in additional gas processing capability in 2011. We currently are building a 12.5 MMcf/d processing facility in our Dorcheat Macedonia field, which we expect to complete during August of this year. The construction of this new facility is in conjunction with our continued development of the field.

Rocky Mountain Region

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

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

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

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

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

DJ Basin Weld County, Colorado

The DJ Basin is a geologic structural basin centered in eastern Colorado that extends into southeast Wyoming, western Nebraska, and western Kansas. Our operations in the DJ Basin are in the oil window of the Niobrara and as of December 31, 2010 consisted of approximately 42,698 gross (29,742 net) total acres.

Commercial development activities began in the DJ Basin in the 1970s. It originally produced natural gas from tight sand reservoirs in the Dakota and J Sands. In the 1990s the shallower Codell sands and Niobrara oil shale were developed and produced oil and associated natural gas. These zones range from 6,300 feet to 8,000 feet with average porosity of 6% to 10% and relatively low permeability of 0.3 millidarcies.

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

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DJ Basin Vertical Exploitation

Our estimated proved reserves in the DJ Basin were 8,402 MBoe at December 31, 2010. As of April 30, 2011, we had a total of 141 gross (133.6 net) producing wells and our net average daily production during April 2011 was approximately 1,124 Boe/d. Our working interest for all producing wells averages is 94.8% and our net revenue interest is approximately 76.5%.

We drill wells vertically in this area to an average depth of approximately 7,000 feet, targeting both the Niobrara and Codell horizons with the same well bore. We have budgeted drilling and completion costs per well of approximately $640,000 and we expect to incur an additional $195,000 per well for refracture stimulation, to be completed in the fifth year after initial completion. Typically, these wells take an average of five days to drill and one day to complete. The average initial 30-day production rate for the 35 wells drilled and producing in 2010 was 56 Boe/d. Our typical well has a hyperbolic decline rate and an average economic life of 32 years. We have identified approximately 91 gross (75.8 net) PUD vertical drilling locations on our acreage in this area.

We intend to employ vertical drilling techniques on 25,098 gross (14,670 net) acres in Weld County. Of these acres, 4,760 gross (4,218 net) acres represent potential unproven drilling locations in our proved reserve report and 20,338 gross (10,452 net) acres represent unproven drilling locations.

The Codell sandstone and Niobrara oil shale are blanket deposits in the DJ Basin. We continue to expand our proved acreage with our vertical program by drilling non-proved locations. Currently, we estimate our capital expenditures for 2011 will be $41.0 million, which includes drilling 66 gross (62.3 net) vertical wells of which 23 are PUD and 43 are non-proved. As of April 30, 2011, we had completed 19 gross (19.0 net) of our 2011 planned wells, 7 proved and 12 non-proved.

DJ Basin Horizontal Exploitation

We intend to use horizontal drilling and multi-stage fracture completion techniques to exploit our remaining 17,600 gross (15,072 net) acres in Weld County. We have 3-D seismic data covering 17,400 gross acres in this area.

Our acreage position in the DJ Basin is offset by EOG Resources, Marathon Oil, Noble Energy and PDC Energy. Noble and PDC have drilled horizontal wells in the area of our acreage and reported initial production rates ranging from 162 Boe/d to 625 Boe/d. Wells on the lower range tend to have shorter horizontal lateral lengths and smaller volumes of proppant used in the fracture stimulation. PDC Energy recently announced the results of the Rickards 41-10H located approximately 6 miles to the north of our acreage. The reported initial production rate was 625 Boe/d with a 30-day average of 310 Boe/d. The well was completed with a 3,900 foot lateral in the Niobrara B interval. A 16-stage fracture stimulation was executed with 3.6 million pounds of proppant. We plan on drilling 4 horizontal Niobrara wells in the DJ Basin in 2011 utilizing similar completion techniques.

North Park Basin Jackson County, Colorado

Current Operations. We control 47,003 gross (39,030 net) acres in the North Park Basin in northern Jackson County, Colorado. The Basin is divided into three principal opportunities: the North and South McCallum units and the non-unit acreage. We operate the North and South McCallum fields, which currently produce CO_2 and light oil from the Dakota/Lakota Group sandstones and oil from a shallow waterflood from the Pierre B sandstone.

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

In the North Park Basin, our estimated proved reserves as of December 31, 2010 were approximately 696.1 MBoe, of which 100% were oil. Our average net production during April 2011 was approximately 140 Boe/d. None of our CO_2 production is currently reflected in our reserve reports.

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Niobrara Oil Shale Potential. All of our 47,003 gross (39,030 net) acres in the North Park Basin are prospective for the Niobrara oil shale. In 2007, EOG Resources began a testing program in the North Park Basin. Through 2010 EOG Resources has drilled 7 and completed 5 horizontal wells targeting the Niobrara. The first two wells experienced average 30-day initial production rates of 159 Boe/d. The next two horizontal wells were completed using longer horizontal laterals and more fracture stimulation stages and had an average 27-day initial production rate of 456 Boe/d. As of April 30, 2011, EOG Resources has permitted 2 additional horizontal wells for the North Park Basin.

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

Currently, there is no take away capacity for natural gas from the North Park Basin. Any future commercial development of the Niobrara oil shale in this area will require significant investment to construct the infrastructure necessary to gather and transport associated natural gas produced from the formation. Although we are not aware of any current plans to construct or fund this construction in the immediate future, we believe that mid-stream companies will construct the necessary infrastructure once the level of commercial natural gas development warrants the capital outlay.

California

In California, we own acreage in four fields: Kern River, Midway Sunset and Greeley, which we operate, and Sargent, which we do not. Our estimated proved reserves in California were 886 MBoe at December 31, 2010. As of April 30, 2011, we had a total of 57 gross (48.7 net) producing wells and our average net daily production was approximately 218 Boe/d. Our working interest for all producing wells averages 85.4% and our net revenue interest is approximately 71.9%. As of December 31, 2010, we have identified approximately 18 gross (13.6 net) PUD locations in California. Currently, we estimate our capital expenditures for 2011 will be $8.7 million, which includes drilling 10 gross (8.0 net) wells, all of which are PUD.

We believe the opportunity to see additional growth exists on the two thermal properties: Kern River and Midway Sunset. Combined, these two properties have up to 16.5 MMBoe of 11° to 12° API gravity crude oil originally in place with very small amounts of production to date. We believe that reservoir parameters are good for thermal operations in both areas. In Kern River, porosities average 31% and permeabilities average from 1,000 to 5,000 millidarcies. In Midway Sunset, porosities average 32% and permeabilities range from 400 to 600 millidarcies. Proved reserves for these two areas are only 573 MBoe, which we believe demonstrates an opportunity for future growth in reserves once thermal operations take effect.

Both Greeley and Sargent produce a lighter crude and do not require thermal stimulation. Potential upside exists in the Sargent field by implementing fracture stimulation of the Purisima sands. These sands have permeability of under 500 millidarcies and porosities of 32%. The operator at Sargent drilled one well through April 30, 2011 and fracture stimulated that well in May 2011.

Proved undeveloped reserves

At December 31, 2010, our proved undeveloped reserves were 21,334.6 Mboe, an increase of 7,343.3 Mboe over our December 31, 2009 proved undeveloped reserves estimate of 13,991.3 Mboe. The reserve change and number of net wells is summarized in the table below for each our regions. The largest changes were realized in the Mid-Continent and Rocky Mountain regions resulting primarily from our acquisition of HEC. This acquisition added 5,691.7 Mboe and accounted for 77.5% of the total increase of 7,343.3 Mboe in 2010. Also contributing to our growth in proved undeveloped reserves were improved

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techniques in stimulating smaller, tighter, higher gas oil ratio sands in the Mid-Continent region that were implemented in 2009 and resulted in a revision of our forecast in 2010. Our total capital expenditure associated with the conversion of proved undeveloped reserves to proved developed reserves in 2010 was $21.6 million.

	2009		2010		Difference	
Region/Area	**MBoe**	**Net Wells**	**MBoe**	**Net Wells**	**MBoe**	**Net Wells**
Mid Continent	11,486.5	109.6	16,890.2	163.3	5,403.7	53.7
Rocky Mountain	1,687.6	30.1	3,897.6	79.3	2,210.0	49.2
California	817.2	30.2	546.7	16.8	(270.5)	(13.4)
Total	13,991.3	169.8	21,334.6	259.4	7,343.3	89.6

Independent Reserve Engineers

The proved reserves estimates for the company for the year ended December 31, 2010 and for BCEC for the year ended December 31, 2009 shown herein have been independently prepared by Cawley, Gillespie & Associates, Inc., which was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-693. Within Cawley, Gillespie & Associates, Inc., the technical person primarily responsible for preparing the estimates shown herein, was Zane Meekins. Mr. Meekins has been practicing consulting petroleum engineering at Cawley, Gillespie & Associates, Inc. since 1989. Mr. Meekins is a Registered Professional Engineer in the State of Texas (License No. 71055) and has over 23 years of practical experience in petroleum engineering, with over 21 years experience in the estimation and evaluation of reserves. He graduated from Texas A&M University in 1987 with a BS in Petroleum Engineering. Mr. Meekins meets or exceeds the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

Technology Used to Establish Proved Reserves

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

In order to establish reasonable certainty with respect to our estimated proved reserves, Cawley, Gillespie & Associates, Inc. employed technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used in the estimation of our proved reserves include, but are not limited to, electrical logs, radioactivity logs, core analyses, geologic maps and available downhole and production data, 3-D seismic data and well test data. Reserves attributable to producing wells with sufficient production history were estimated using appropriate decline curves or other performance relationships. Reserves attributable to producing wells with limited production history and for undeveloped locations were estimated using performance from analogous wells in the surrounding area and geologic data to assess the reservoir continuity. These wells were considered to be analogous based on production performance from the same formation and completion using similar techniques. The evaluation included an assessment of the beneficial impact of the use of multi-stage hydraulic fracture

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stimulation treatments on estimated recoverable reserves. In addition to assessing reservoir continuity, geologic data from well logs, core analyses and 3-D seismic data were used to estimate original oil in place in certain areas.

Internal Controls over Reserves Estimation Process

We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with our independent reserve engineers to ensure the integrity, accuracy and timeliness of data furnished to our independent reserve engineers in their reserves estimation process. Our Executive Vice President Engineering and Planning is the technical person within the company primarily responsible for overseeing the preparation of our reserves estimates. He has over 29 years of industry experience and has evaluated numerous properties throughout the United States and Canada with an emphasis on California in light oil and natural gas, heavy oil, conventional and unconventional reservoirs, operations, reservoir development and property evaluation. He holds a Bachelors of Science degree in Petroleum Engineering and is an active member with the Society of Petroleum Engineers.

Throughout each fiscal year, our technical team meets with representatives of our independent reserve engineers to review properties and discuss methods and assumptions used in preparation of the proved reserves estimates. Historically, we had no formal committee specifically designated to review our reserves reporting and our reserves estimation process, and a preliminary copy of the reserve report was reviewed by our Executive Vice President Engineering and Planning with representatives of our independent reserve engineers and internal technical staff. We have recently designated a Reserve Committee of our board of directors which will actively oversee our reserve reporting process. See "*Management Committees of the Board of Directors Reserve Committee*."

Operating Data

The following table sets forth our operating data for the three years ended December 31, 2008, 2009 and 2010.

	2008	2009	2010
Oil:			
Production (MBbls)	453.7	507.4	481.6
Average sales price (per Bbl), including hedges	$ 79.59	$ 67.40	$ 74.32
Average sales price (per Bbl), excluding hedges	$ 88.09	$ 54.40	$ 73.66
Natural Gas:			
Production (MMcf)	668.9	939.0	1,334.9
Average sales price (per Mcf), including hedges	$ 7.93	$ 5.05	$ 5.33
Average sales price (per Mcf), excluding hedges	$ 7.72	$ 3.91	$ 4.77
Natural Gas Liquids:			
Production (MBbls)	35.5	69.1	129.6
Average sales price (per Bbl), including hedges	$ 57.45	$ 41.77	$ 56.22
Average sales price (per Bbl), excluding hedges	$ 57.45	$ 41.77	$ 56.22
Oil Equivalents:			
Production (MBoe)	600.7	733.0	833.7
Average daily production (Boe/d)	1,641	2,008	2,284
Average Production Costs (per Boe)(1)	$ 34.02	$ 18.35	$ 18.28

(1) Excludes ad valorem and severance taxes.

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Principal Customers

Two of our customers, Lion Oil and Plains Marketing, comprised 47% and 39%, respectively, of total revenue for the year ended December 31, 2010 and the three months ended March 31, 2011.

Delivery Commitments

We do not have any material delivery commitments.

Productive Wells

The following table sets forth the number of oil and natural gas wells in which we owned a working interest at April 30, 2011.

	Oil		Natural Gas(1)		Total		Operated	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Mid-Continent	112	96.9			112	96.9	111	96.7
Rocky Mountain	199	191.6			199	191.6	197	190.9
California	57	48.7			57	48.7	46	43.2
Total	368	337.2			368	337.2	354	330.8

(1) All gas production is associated gas from producing oil wells.

Acreage

The following table sets forth certain information with respect to our developed and undeveloped acreage as of December 31, 2010.

	Undeveloped		Developed	
	Gross	Net	Gross	Net
Mid-Continent			18,449	15,165
Rocky Mountain(1)	52,643	38,904	37,058	29,868
California(2)	200	144	8,740	4,868
Total	52,843	39,048	64,247	49,901

(1) Assuming successful wells are not drilled to develop the Rocky Mountain acreage and leases are not extended, leaseholds expiring over the next three years will be 7,284 net acres in 2011, 3,076 net acres in 2012 and 11,120 net acres in 2013.

(2) Assuming successful wells are not drilled to develop the California acreage and leases are not extended, leaseholds expiring over the next three years will be zero net acres in 2011, 15 net acres in 2012 and 36 net acres in 2013.

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Drilling Activity

Exploratory

The following table describes the exploratory wells we drilled during the years ended December 31, 2008, 2009 and 2010.

	Productive Wells		Dry Wells		Total	
Year	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
2008	6	6.0			6	6.0
2009						
2010	15	15.0			15	15.0

Development

The following table describes the development wells we drilled during the years ended December 31, 2008, 2009 and 2010.

	Productive Wells		Dry Wells		Total	
Year	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
2008	27	26.8			27	26.8
2009(1)						
2010(1)	27	27.0			27	27.0

(1) We contract operated for HEC from May 2009 until we acquired the properties in December 2010. Excluded from the development activity are 4 wells (2.5 net) and 12 wells (9.0 net) drilled as contract operator for HEC during years 2009 and 2010, respectively, that we had a minority working interest.

Present Activity

The following table describes drilling activities as of April 30, 2011.

	Development Wells		Exploratory Wells		Total	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Mid-Continent	2.0	1.7			2.0	1.7
Rocky Mountain			2.0	2.0	2.0	2.0
California	1.0	0.5			1.0	0.5
Total	3.0	2.2	2.0	2.0	5.0	4.2

Additionally, to accommodate future increased gas volumes, we are in the process of building a 12.5 MMcf/d processing facility in our Dorcheat Macedonia Field in the Mid-Continent region.

Hedging Activity

In addition to supply and demand, oil and gas prices are affected by seasonal, economic and geo-political factors that we can neither control nor predict. We attempt to mitigate a portion of our price risk through the use of derivative transactions.

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As of April 30, 2011, we had the following economic hedges in place, which settle monthly:

Oil Contracts

Period	Type	Volume/Month (Bbls)	Index[(1)]	Floor	Ceiling	Fixed Price
January 1 - December 31, 2011	Collar	15,392	WTI	$ 90.00	$ 123.00	
April 1 - December 31, 2011	Collar	24,444	WTI	$ 80.00	$ 140.00	
January 1 - December 31, 2011	Swap	8,917	WTI			$ 64.45
January 1 - December 31, 2011	Swap	1,591	WTI			$ 63.87
January 1 - December 31, 2012	Collar	13,956	WTI	$ 90.00	$ 123.00	
January 1 - December 31, 2012	Swap	8,206	WTI			$ 62.95
January 1 - December 31, 2012	Swap	1,520	WTI			$ 63.47
January 1 - April 31, 2013	Collar	12,654	WTI	$ 90.00	$ 123.00	
January 1 - October 31, 2013	Swap	7,542	WTI			$ 61.50

Natural Gas Contracts

Period	Type	Volume/Month (MMBtu)	Index	Fixed Price
January 1 - December 31, 2011	Swap	18,298	Henry Hub	$ 7.10
January 1 - December 31, 2012	Swap	16,860	Henry Hub	$ 6.75
January 1 - October 31, 2013	Swap	15,481	Henry Hub	$ 6.40

(1) WTI refers to West Texas Intermediate price as quoted on the New York Mercantile Exchange.

We did not apply hedge accounting treatment to any of the 2010 and 2011 contracts. Settlements on these contracts will not impact our realized commodity prices during the periods they cover. Instead, any settlements on these contracts are shown as a component of other income and expenses as a realized (gain) loss on derivative instruments. See Note 12 to our consolidated financial statements for additional information regarding our derivative instruments.

Title to Properties

Our properties are subject to customary royalty interests, liens incident to operating agreements, liens for current taxes and other burdens, including other mineral encumbrances and restrictions. We do not believe that any of these burdens materially interfere with our use of the properties in the operation of our business. We believe that we have generally satisfactory title to or rights in all of our producing properties. As is customary in the oil and gas industry, we make minimal investigation of title at the time we acquire undeveloped properties. We make title investigations and receive title opinions of local counsel only before we commence drilling operations. We believe that we have satisfactory title to all of our other assets. Although title to our properties is subject to encumbrances in certain cases, we believe that none of these burdens will materially detract from the value of our properties or from our interest therein or will materially interfere with the operation of our business.

Competition

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

Regulation of the Oil and Natural Gas Industry

Our operations are substantially affected by federal, state and local laws and regulations. In particular, oil and natural gas production and related operations are, or have been, subject to price controls, taxes and numerous other laws and regulations. All of the jurisdictions in which we own or operate properties for oil and natural gas production have statutory provisions regulating the exploration for and production of oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, sourcing and disposal of water used in the drilling and completion process, and the abandonment of wells. Our operations are also subject to various conservation laws and regulations. These include regulation of the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area, and the unitization or pooling of oil and natural gas wells, as well as regulations that generally prohibit the venting or flaring of natural gas and that impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells.

The regulatory burden on the industry increases the cost of doing business and affects profitability. Failure to comply with applicable laws and regulations can result in substantial penalties. Furthermore, such laws and regulations are frequently amended or reinterpreted, and new proposals that affect the oil and natural gas industry are regularly considered by Congress, the states, the Federal Energy Regulatory Commission, or FERC, and the courts. We believe we are in substantial compliance with all applicable laws and regulations, and that continued substantial compliance with existing requirements will not have a material adverse effect on our financial position, cash flows or results of operations. Nor are we currently aware of any specific pending legislation or regulation that is reasonably likely to be enacted, or for which we cannot predict the likelihood of enactment, and that is reasonably likely to have a material effect on our financial position, cash flows or results of operations.

Regulation of transportation of oil

Sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at negotiated prices. Nevertheless, Congress could reenact price controls in the future.

Our sales of crude oil are affected by the availability, terms and cost of transportation. Interstate transportation of oil by pipeline is regulated by FERC pursuant to the ICA, EPAct 1992 and the rules and regulations promulgated under those laws. The ICA and its implementing regulations require that tariff rates for interstate service on oil pipelines, including interstate pipelines that transport crude oil and refined products (collectively referred to as "petroleum pipelines"), be just and reasonable and non-discriminatory and that such rates and terms and conditions of service be filed with FERC. EPAct 1992 deemed certain interstate petroleum pipeline rates then in effect to be just and reasonable under the ICA, which are commonly referred to as "grandfathered rates." Pursuant to EPAct 1992, FERC also adopted a generally applicable ratemaking methodology, which, as currently in effect, allows petroleum pipelines to change their rates provided they do not exceed prescribed ceiling levels that are tied to changes in the Producer Price Index for Finished Goods ("PPI"), plus 1.3 percent. For the five-year period beginning July 1, 2011, the index will be PPI plus 2.65%.

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FERC has also established cost-of-service ratemaking, market-based rates, and settlement rates as alternatives to the indexing approach. A pipeline may file rates based on its cost-of-service if there is a substantial divergence between its actual costs of providing service and the rate resulting from application of the index. A pipeline may charge market-based rates if it establishes that it lacks significant market power in the affected markets. Further, a pipeline may establish rates through settlement with all current non-affiliated shippers.

Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any way that is of material difference from those of our competitors who are similarly situated.

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all similarly situated shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by prorationing provisions set forth in the pipelines' published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our similarly situated competitors.

Regulation of transportation and sales of natural gas

Historically, the transportation and sale for resale of natural gas in interstate commerce has been regulated by the FERC under the Natural Gas Act of 1938 ("NGA"), the Natural Gas Policy Act of 1978 ("NGPA"), and regulations issued under those statutes. In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at market prices, Congress could reenact price controls in the future. Deregulation of wellhead natural gas sales began with the enactment of the NGPA and culminated in adoption of the Natural Gas Wellhead Decontrol Act which removed all price controls affecting wellhead sales of natural gas effective January 1, 1993.

FERC regulates interstate natural gas transportation rates, and terms and conditions of service, which affect the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas. Since 1985, the FERC has endeavored to make natural gas transportation more accessible to natural gas buyers and sellers on an open and non-discriminatory basis. The FERC has stated that open access policies are necessary to improve the competitive structure of the interstate natural gas pipeline industry and to create a regulatory framework that will put natural gas sellers into more direct contractual relations with natural gas buyers by, among other things, unbundling the sale of natural gas from the sale of transportation and storage services. Beginning in 1992, the FERC issued a series of orders, beginning with Order No. 636, to implement its open access policies. As a result, the interstate pipelines' traditional role of providing the sale and transportation of natural gas as a single service has been eliminated and replaced by a structure under which pipelines provide transportation and storage service on an open access basis to others who buy and sell natural gas. Although the FERC's orders do not directly regulate natural gas producers, they are intended to foster increased competition within all phases of the natural gas industry.

In 2000, the FERC issued Order No. 637 and subsequent orders, which imposed a number of additional reforms designed to enhance competition in natural gas markets. Among other things, Order No. 637 revised the FERC's pricing policy by waiving price ceilings for short-term released capacity for a two-year experimental period, and effected changes in FERC regulations relating to scheduling procedures, capacity segmentation, penalties, rights of first refusal and information reporting.

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Gathering services, which occur upstream of jurisdictional transmission services, are regulated by the states onshore and in state waters. Although the FERC has set forth a general test for determining whether facilities perform a nonjurisdictional gathering function or a jurisdictional transmission function, the FERC's determinations as to the classification of facilities is done on a case by case basis. To the extent that the FERC issues an order which reclassifies transmission facilities as gathering facilities, and depending on the scope of that decision, our costs of getting gas to point of sale locations may increase. State regulation of natural gas gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements. Although such regulation has not generally been affirmatively applied by state agencies, natural gas gathering may receive greater regulatory scrutiny in the future.

Intrastate natural gas transportation and facilities are also subject to regulation by state regulatory agencies, and certain transportation services provided by intrastate pipelines are also regulated by FERC. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is of material difference from those of our competitors. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas.

Regulation of production

The production of oil and natural gas is subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations. Federal, state and local statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. All of the states in which we own and operate properties have regulations governing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum allowable rates of production from oil and natural gas wells, the regulation of well spacing, and plugging and abandonment of wells. The effect of these regulations is to limit the amount of oil and natural gas that we can produce from our wells and to limit the number of wells or the locations at which we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction.

The failure to comply with these rules and regulations can result in substantial penalties. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

Market transparency rules

In 2007, FERC took steps to enhance its market oversight and monitoring of the natural gas industry by issuing several rulemaking orders designed to promote gas price transparency and to prevent market manipulation. In December 2007, FERC issued a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing, or Order No. 704. Pursuant to Order No. 704, wholesale buyers and sellers of annual quantities of 2.2 million MMBtu or more of natural gas in the previous calendar year, including intrastate natural gas pipelines, natural gas gatherers, natural gas processors, natural gas marketers and natural gas producers, are required to report, by May 1 of each year, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to, or may contribute to, the formation of price indices. Order No. 704 also requires market participants to indicate whether they report prices to any index publishers and, if so,

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whether their reporting complies with FERC's policy statement on price reporting. Some of our operations may be required to comply with Order No. 704's annual reporting requirements.

In 2008, the FERC issued Order No. 720, which increases the Internet posting obligations of interstate pipelines, and also requires "major non-interstate" pipelines (defined as pipelines that are not natural gas companies under the NGA that deliver more than 50 million MMBtu annually and including gathering systems) to post on the Internet the daily volumes scheduled for each receipt and delivery point on their systems with a design capacity of 15,000 MMBtu per day or greater. Numerous parties requested modification or reconsideration of this rule. An order on rehearing, Order No. 720-A, was issued on January 21, 2010. In that order the FERC reaffirmed its holding that it has jurisdiction over major non-interstate pipelines for the purpose of requiring public disclosure of information to enhance market transparency. Order No. 720-A also granted clarification regarding application of the rule. Two parties have filed appeals of Order Nos. 720 and 720-A to the Fifth Circuit. The parties have filed briefs but no decision has been issued. Unless they qualify for exemptions established by FERC, some of our operations may be required to comply with Order No. 720's posting requirements.

In May 2010, the FERC issued Order No. 735, which requires intrastate pipelines providing transportation services under Section 311 of the NGPA and Hinshaw pipelines operating under Section 1(c) of the NGA to report on a quarterly basis more detailed transportation and storage transaction information, including: rates charged by the pipeline under each contract; receipt and delivery points and zones or segments covered by each contract; the quantity of natural gas the shipper is entitled to transport, store, or deliver; the duration of the contract; and whether there is an affiliate relationship between the pipeline and the shipper. Order No. 735 further requires that such information must be supplied through a new electronic reporting system and will be posted on FERC's website, and that such quarterly reports may not contain information redacted as privileged. The FERC promulgated this rule after determining that such transactional information would help shippers make more informed purchasing decisions and would improve the ability of both shippers and the FERC to monitor actual transactions for evidence of market power or undue discrimination. Order No. 735 also extends the Commission's periodic review of the rates charged by the subject pipelines from three years to five years. In December 2010, the Commission issued Order No. 735-A. In Order No. 735-A, the Commission generally reaffirmed Order No. 735 requiring section 311 and "Hinshaw" pipelines to report on a quarterly basis storage and transportation transactions containing specific information for each transaction, aggregated by contract.

In October 2010, the FERC issued a Notice of Inquiry seeking public comment on the issue of whether and how parties that hold firm capacity on some intrastate pipelines can allow others to use their capacity, including to what extent buy/sell transactions should permitted and whether the FERC should consider requiring such pipelines to offer capacity release programs. In the Notice of Inquiry, the FERC granted a blanket waiver regarding such transactions while the FERC is considering these policy issues. The comment period has ended but the FERC has not yet issued an order.

With regard to our physical sales of natural gas, we are required to observe anti-market manipulation laws and related regulations enforced by the FERC. The Energy Policy Act of 2005 ("EPAct 2005") amended the NGA to add an anti-manipulation provision which makes it unlawful for any entity to engage in prohibited behavior to be prescribed by FERC, and furthermore provides FERC with additional civil penalty authority. On January 19, 2006, FERC issued Order No. 670, a rule implementing the anti-manipulation provision of EPAct 2005, and subsequently denied rehearing. The rule makes it unlawful for any entity, directly or indirectly, in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC, or the purchase or sale of transportation services subject to the jurisdiction of FERC, (1) to use or employ any device, scheme or artifice to defraud; (2) to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (3) to engage in any act, practice, or course of business that operates as a fraud or deceit upon any person. The anti-manipulation rules do not apply to activities that relate only to intrastate or other

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non-jurisdictional sales or gathering, but do apply to activities of gas pipelines and storage companies that provide interstate services, such as Section 311 service, as well as otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction, which now includes the annual reporting requirements under Order 704.

With regard to our sales of petroleum and petroleum products, we are required to observe anti-market manipulations laws and related regulations enforced by the Federal Trade Commission ("FTC"). In addition, the CFTC has enforcement authority over market manipulation with respect to certain derivative contracts. Each of FERC, the FTC and the CFTC has the a power to asses fines of $1 million per day per violation of applicable anti-market manipulation laws and regulations. Should we violate anti-market manipulation laws and regulations, we could also be subject to third party damage claims by, among others, sellers, royalty owners and taxing authorities.

Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, FERC and the courts. We cannot predict the ultimate impact of these or the above regulatory changes to our natural gas operations. We do not believe that we would be affected by any such action materially differently than similarly situated competitors.

Environmental, Health and Safety Regulation

Our exploration, development, production and processing operations are subject to various federal, state and local laws and regulations relating to health and safety, the discharge of materials and environmental protection. These laws and regulations may, among other things, require the acquisition of permits to conduct exploration, drilling and production operations; govern the amounts and types of substances that may be released into the environment in connection with oil and gas drilling and production; restrict the way we handle or dispose of our wastes; limit or prohibit construction or drilling activities in sensitive areas such as wetlands, wilderness areas or areas inhabited by endangered or threatened species; require investigatory and remedial actions to mitigate pollution conditions caused by our operations or attributable to former operations; and impose obligations to reclaim and abandon well sites and pits. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations and the issuance of orders enjoining some or all of our operations in affected areas.

These laws and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and gas industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, the Congress and federal and state agencies frequently revise environmental, health and safety laws and regulations, and any changes that result in more stringent and costly waste handling, disposal, cleanup and remediation requirements for the oil and gas industry could have a significant impact on our operating costs.

The clear trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, and thus, any changes in environmental laws and regulations or re-interpretations of enforcement policies that result in more stringent and costly waste handling, storage, transport, disposal, or remediation requirements could have a material adverse effect on our operations and financial position in the future. We may be unable to pass on such increased compliance costs to our customers. Moreover, accidental releases or spills may occur in the course of our operations, and we cannot assure you that we will not incur significant costs and liabilities as a result of such releases or spills, including any third party claims for damage to property, natural resources or persons. We maintain insurance against costs of clean-up operations, but we are not fully insured against all such risks. While we believe that we are in substantial compliance with existing environmental laws and regulations and that current requirements would not have a material adverse effect on our financial condition or results of operations, there is no assurance that this will continue in the future.

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The following is a summary of the more significant existing environmental, health and safety laws and regulations to which our business operations are subject and for which compliance in the future may have a material adverse impact on our capital expenditures, results of operations or financial position.

Hazardous substances and waste

CERCLA, also known as the Superfund law, and comparable state laws impose liability without regard to fault or the legality of the original conduct on certain classes of persons who are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include current and prior owners or operators of the site where the release occurred and entities that disposed or arranged for the disposal of the hazardous substances found at the site. Under CERCLA, these "responsible persons" may be subject to strict, joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources, and for the costs of certain health studies. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances or other pollutants into the environment. We generate materials in the course of our operations that may be regulated as hazardous substances.

We also generate solid and hazardous wastes that are subject to the requirements of the RCRA, as amended, and comparable state statutes. RCRA imposes requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes. In the course of our operations we generate petroleum hydrocarbon wastes and ordinary industrial wastes that may be regulated as hazardous wastes. RCRA regulations specifically exclude from the definition of hazardous waste "drilling fluids, produced waters and other wastes associated with the exploration, development or production of crude oil, natural gas or geothermal energy." However, legislation has been proposed in Congress from time to time that would reclassify certain natural gas and oil exploration and production wastes as "hazardous wastes," which would make the reclassified wastes subject to much more stringent handling, disposal and clean-up requirements. If such legislation were to be enacted, it could have a significant impact on our operating costs, as well as the natural gas and oil industry in general.

We currently own or lease, and have in the past owned or leased, properties that have been used for numerous years to explore and produce oil and natural gas. Although we have utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons and wastes may have been disposed of or released on or under the properties owned or leased by us or on or under the other locations where these hydrocarbons and wastes have been taken for treatment or disposal. In addition, certain of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons and wastes was not under our control. These properties and wastes disposed thereon may be subject to CERCLA, RCRA and analogous state laws. Under these laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including groundwater contaminated by prior owners or operators), and to perform remedial operations to prevent future contamination.

Pipeline safety and maintenance

Pipelines, gathering systems and terminal operations are subject to increasingly strict safety laws and regulations. Both the transportation and storage of refined products and crude oil involve a risk that hazardous liquids may be released into the environment, potentially causing harm to the public or the environment. In turn, such incidents may result in substantial expenditures for response actions, significant government penalties, liability to government agencies for natural resources damages, and significant business interruption. The U.S. Department of Transportation ("DOT") has adopted safety regulations with respect to the design, construction, operation, maintenance, inspection and management of our

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pipeline and storage facilities. These regulations contain requirements for the development and implementation of pipeline integrity management programs, which include the inspection and testing of pipelines and the correction of anomalies. These regulations also require that pipeline operation and maintenance personnel meet certain qualifications and that pipeline operators develop comprehensive spill response plans.

There have been recent initiatives to strengthen and expand pipeline safety regulations and to increase penalties for violations. New pipeline safety legislation requiring more stringent spill reporting and disclosure obligations has been introduced in the U.S. Congress and was passed by the U.S. House of Representatives in 2010, but was not voted on in the U.S. Senate. Similar legislation is being considered by Congress again this year, either independently or in conjunction with the reauthorization of the Pipeline Safety Act. The Department of Transportation has also recently proposed legislation providing for more stringent oversight of pipelines and increased penalties for violations of safety rules, which is in addition to the Pipeline and Hazardous Materials Safety Administration's announced intention to strengthen its rules. DOT recently promulgated new regulations extending safety rules to certain low pressure, small diameter pipelines in rural areas.

Air emissions

The Clean Air Act, as amended ("CAA"), and comparable state laws and regulations restrict the emission of air pollutants from many sources, including oil and gas operations, and impose various monitoring and reporting requirements. These laws and regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions. Obtaining permits has the potential to delay the development of oil and natural gas projects.

On August 20, 2010, the U.S. Environmental Protection Agency, or the EPA, published new regulations under the CAA to control emissions of hazardous air pollutants from existing stationary reciprocating internal combustion engines. The rule may require us to undertake certain expenditures and activities, likely including purchasing and installing emissions control equipment, such as oxidation catalysts or non-selective catalytic reduction equipment, on a portion of our engines located at major sources of hazardous air pollutants and all our engines over a certain size regardless of location, following prescribed maintenance practices for engines (which are consistent with our existing practices), and implementing additional emissions testing and monitoring. On October 19, 2010, industry groups submitted a legal challenge to the U.S. Court of Appeals for the D.C. Circuit and a Petition for Administrative Reconsideration to the EPA for some monitoring aspects of the rule. The legal challenge has been held in abeyance since December 3, 2010, pending the EPA's consideration of the Petition for Administrative Reconsideration. On January 5, 2011, the EPA approved the request for reconsideration of the monitoring issues and on March 9, 2011, the EPA issued a new proposed rule and a direct final rule effective on May 9, 2011 to clarify compliance requirements related to operation and maintenance procedures for continuous parametric monitoring systems. If significant adverse comments are filed on the direct final rule, the EPA would address public comments in a subsequent final rule. At this point, we cannot predict when, how or if comments will be filed on the direct final rule or if a court ruling would modify the final rule. Compliance with the final rule currently is required by October 2013.

In June 2010, the EPA formally proposed modifications to existing regulations under the CAA that established new source performance standards for manufacturers, owners and operators of new, modified and reconstructed stationary internal combustion engines. The proposed rule modifications, if adopted as drafted by the EPA, may require us to undertake significant expenditures, including expenditures for purchasing, installing, monitoring and maintaining emissions control equipment on a potentially significant percentage of our natural gas compression engine fleet. At this point, we cannot predict the final regulatory requirements or the cost to comply with such requirements.

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Climate change

The United States is a party to the United Nations Framework Convention on Climate Change, an international treaty focused on stabilizing greenhouse gas concentrations in the atmosphere at a level that would prevent serious damage to the climate system. While neither the treaty itself, nor subsequent related conferences, have established an obligation for the U.S. to reduce its greenhouse gas emissions by a set amount, it has put significant political pressure on the U.S. to take responsive action. Both houses of Congress have previously considered legislation to reduce emissions of GHGs. Any future federal laws, treaties or implementing regulations that may be adopted to address greenhouse gas emissions could require us to incur increased operating costs and could adversely affect demand for the oil and natural gas we produce.

In addition, the EPA has begun to regulate GHG emissions. In December 2009, the EPA published its finding that certain emissions of greenhouse gases presented an endangerment to human health and the environment. These findings by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of GHGs under existing provisions of the federal Clean Air Act. Consequently, the EPA is requiring a reduction in emissions of greenhouse gases from new motor vehicles beginning with the 2012 model year. Furthermore, the EPA published a final rule on June 3, 2010 to address the permitting of GHG emissions from stationary sources under the Prevention of Significant Deterioration and Title V permitting programs. This rule "tailors" these permitting programs to apply to certain stationary sources of GHG emissions, such as power plants and oil refineries, in a multi-step process, with the largest sources first subject to permitting. Facilities required to obtain PSD permits for their GHG emissions will be required to meet emissions limits that are based on the "best available control technology," which will be established by the permitting agencies on a case-by-case basis. Starting in January 2011, stationary sources that are already obtaining a Clean Air Act permit for other pollutants must include greenhouse gases in their permits if they emit at least 75,000 tons of these emissions a year. In July 2012, the rule expands to include all new facilities that emit at least 100,000 tons of greenhouse gases per year.

In addition, on September 2009, the EPA issued a final rule requiring the reporting of GHGs from specified large GHG emission sources beginning in 2011 for emissions in 2010. Our McKamie processing facility in Arkansas is currently required to report under this rule this year. On November 30, 2009, the EPA published a final rule expanding the existing GHG monitoring and reporting rule to include onshore and offshore oil and gas production facilities and onshore oil and natural gas processing, transmission, storage and distribution facilities. Reporting of GHG emissions from such facilities will be required on an annual basis, with reporting beginning in 2012 for emissions occurring in 2011. Our McKamie processing facility and our North Park Basin, Colorado facility are currently required to report under this rule. The EPA also published a final rule requiring reporting for natural gas liquid fractionators, which applies to the McKamie processing facility and a separate reporting rule for suppliers of carbon dioxide, which affects our operations in the North Park Basin. Several of the EPA's GHG rules are being challenged in court proceedings and depending on the outcome of such proceedings, such rules may be modified or rescinded or the EPA could develop new rules. The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of greenhouse gases from, our equipment and operations could require us to incur costs to reduce emissions of greenhouse gases associated with our operations or could adversely affect demand for the oil and natural gas we produce.

Even if such legislation is not adopted at the national level, almost one-half of the states have begun taking actions to control and/or reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Although most of the state-level initiatives have to date focused on large sources of greenhouse gas emissions, such as coal-fired electric plants, it is possible that smaller sources of emissions could become subject to greenhouse gas emission limitations or allowance purchase requirements in the future.

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Any one of these climate change regulatory and legislative initiatives could have a material adverse effect on our business, financial condition and results of operations.

Legislation or regulations that may be adopted to address climate change could also affect the markets for our products by making our products more or less desirable than competing sources of energy. To the extent that our products are competing with higher GHG emitting energy sources such as coal, our products would become more desirable in the market with more stringent limitations on GHG emissions. To the extent that our products are competing with lower GHG emitting energy sources such as solar and wind, our products would become less desirable in the market with more stringent limitations on GHG emissions. We cannot predict with any certainty at this time how these possibilities may affect our operations.

Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events. If any such effects were to occur, they could adversely affect or delay demand for the oil or natural gas or otherwise cause us to incur significant costs in preparing for or responding to those effects.

Water discharges

The Federal Water Pollution Control Act, as amended, or the Clean Water Act ("CWA"), and analogous state laws impose restrictions and controls regarding the discharge of pollutants into waters of the United States. Pursuant to the CWA and analogous state laws, permits must be obtained to discharge pollutants into state waters or waters of the U.S. Any such discharge of pollutants into regulated waters must be performed in accordance with the terms of the permit issued by the EPA or the analogous state agency. The CWA and regulations implemented thereunder also prohibit the discharge of dredge and fill material into regulated waters, including jurisdictional wetlands, unless authorized by an appropriately issued permit. Spill prevention, control and countermeasure requirements under federal law require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. In addition, the CWA and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. Federal and state regulatory agencies can impose administrative, civil and criminal penalties as well as other enforcement mechanisms for non-compliance with discharge permits or other requirements of the CWA and analogous state laws and regulations.

Endangered Species Act

The federal Endangered Species Act, as amended, ("ESA") restricts activities that may affect endangered and threatened species or their habitats. While some of our facilities may be located in areas that are designated as habitat for endangered or threatened species, we believe that we are in substantial compliance with the ESA. However, the designation of previously unidentified endangered or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas.

Employee health and safety

We are subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act, as amended (the "OSH Act"), and comparable state statutes, whose purpose is to protect the health and safety of workers. In addition, the OSH Act's hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in our operations and that this information

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be provided to employees, state and local government authorities and citizens. We believe that we are in substantial compliance with all applicable laws and regulations relating to worker health and safety.

Hydraulic fracturing

Regulations relating to hydraulic fracturing. The federal Safe Drinking Water Act ("SDWA"), and comparable state statutes may restrict the disposal, treatment or release of water produced or used during oil and gas development. Subsurface emplacement of fluids (including disposal wells or enhanced oil recovery) is governed by federal or state regulatory authorities that, in some cases, include the state oil and gas regulatory or the state's environmental authority. The federal Energy Policy Act of 2005 amended the Underground Injection Control, or UIC, provisions of the SDWA to expressly exclude hydraulic fracturing from the definition of "underground injection." However, the U.S. Senate and House of Representatives are currently considering bills entitled the Fracturing Responsibility and Awareness of Chemicals Act, or the FRAC Act, to amend the SDWA to repeal this exemption. If enacted, the FRAC Act would amend the definition of "underground injection" in the SDWA to encompass hydraulic fracturing activities. If enacted, such a provision could require hydraulic fracturing operations to meet permitting and financial assurance requirements, adhere to certain construction specifications, fulfill monitoring, reporting, and recordkeeping obligations, and meet plugging and abandonment requirements. The FRAC Act also proposes to require the reporting and public disclosure of chemicals used in the fracturing process. If the exemption for hydraulic fracturing is removed from the SDWA, or if the FRAC Act or other legislation is enacted at the federal, state or local level, any restrictions on the use of hydraulic fracturing contained in any such legislation could have a significant impact on our financial condition and results of operations.

Federal agencies are also considering regulation of hydraulic fracturing. The EPA recently asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the SDWA's Underground Injection Control Program. While the EPA has yet to take any action to enforce or implement this newly asserted regulatory authority, the EPA's interpretation without formal rule making has been challenged and industry groups have filed suit challenging the EPA's interpretation. If the EPA prevails in this lawsuit, its interpretation could result in enforcement actions against service providers or companies that used diesel products in the hydraulic fracturing process or could require such providers or companies to conduct additional studies regarding diesel in the groundwater. The EPA is also collecting information as part of a study into the effects of hydraulic fracturing on drinking water. The results of this study, expected in late 2012, could result in additional regulations, which could lead to operational burdens similar to those described above. The United States Department of the Interior is likewise considering whether to impose disclosure requirements or other mandates for hydraulic fracturing on federal land.

Several state governments in the areas where we operate have adopted or are considering adopting additional requirements relating to hydraulic fracturing that could restrict its use in certain circumstances or make it more costly to utilize. Such measures may address any risk to drinking water, the potential for hydrocarbon migration and disclosure of the chemicals used in fracturing. For example, the State of Colorado, in response to an EPA request, has asked other companies operating in Colorado to report whether diesel products were used in the hydraulic fracturing process from 2004 to 2009. The State of Colorado may conduct additional investigations related to this inquiry. Any enforcement actions or requirements of additional studies or investigations by governmental authorities where we operate could increase our operating costs and cause delays or interruptions of our operations.

At this time, it is not possible to estimate the potential impact on our business of these state and local actions or the enactment of additional federal or state legislation or regulations affecting hydraulic fracturing.

Our use of hydraulic fracturing. We use hydraulic fracturing as a means to maximize production of oil and gas from formations having low permeability such that natural flow is restricted. Fracture stimulation has been used for decades in both the Rocky Mountains and Mid Continent. In the Rocky Mountains,

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other companies in the oil and gas industry have fracture stimulated tens of thousands of wells since the mid 1980s. We and our predecessor companies have completed over 300 fracture stimulations since acquiring assets in the DJ Basin in 1999. At our Dorcheat property in the Mid-Continent region, fracture stimulation has been performed since the 1970s and has been used more universally since the early 1990s. We and our predecessor companies have completed over 40 fracture stimulations since acquiring our Dorcheat properties in mid-2008.

We expect that approximately 91% of our total acreage held as of December 31, 2010 will be subject to hydraulic fracturing in one or more reservoirs, which corresponds to approximately 44% of our total proved reserves. It should be noted that a significant portion of our total acreage does not contain proved reserves at this time.

Our use of hydraulic fracturing is limited mainly to our Mid-Continent and Rocky Mountain regions. Although the cost of each well varies, costs incurred in connection with hydraulic fracturing activities as a percentage of the total cost of drilling and completing a new-drill well average approximately 21% (or $350,000) in our Mid-Continent region and 46% (or $385,000) in our Rocky Mountain region. These costs are accounted for in the same way that all other costs of drilling and completing our wells are accounted for and are included in our normal capital expenditure budget, which is funded through operating cash flows or borrowings under our credit facility. Based on the expected capital forecast in our proved reserve report, we estimate that we will spend approximately $93.1 million for future fracturing activities on both new-drill wells and workovers on existing wells.

For as long as we have owned and operated properties subject to hydraulic fracturing, there have not been any incidents, citations or suits related to fracturing operations or related to environmental concerns from fracturing operations.

We periodically review our plans and policies regarding oil and gas operations, including hydraulic fracturing, in order to minimize any potential environmental impact. We adhere to applicable legal requirements and industry practices for groundwater protection. Our operations are subject to close supervision by state and federal regulators (including the Bureau of Land Management with respect to federal acreage), who frequently inspect our fracturing operations.

During well construction, steel casing pipe and concrete are employed for protection. Once the pipe is set in place, cement is pumped into the well where it hardens to create an isolating barrier between the steel casing pipe and the surrounding geological formations. In accordance with best industry practices, casing and cement design conforms to the applicable requirements and standards of state agencies. As an example, for any fresh water aquifers, a separate string of casing is set below the base as part of the casing design to eliminate any "pathway" for the fracturing fluid to contact any fresh water aquifers during the hydraulic fracturing operations. Furthermore the hydrocarbon bearing formations are generally separated from any usable underground fresh water aquifers by thousands of feet of impermeable rock layers. This distance is approximately 5,200 feet and 6,200 feet, respectively, for our Rockies and Mid-Continent reservoirs that are being fracture stimulated. This wide separation serves as a protective barrier that prevents any migration of fracturing fluids or hydrocarbons upwards into any groundwater zones. In addition, the vendors conducting hydraulic fracturing on our properties monitor pump rates and pressures during the fracturing treatments. This monitoring occurs on a real-time basis to identify abrupt changes in rate or pressure, which permits the operator to modify or cease the fracturing process.

Typical hydraulic fracturing treatments are made up of water, chemical additives and sand. We utilize major hydraulic fracturing service companies who track and report all additive chemicals that are used in fracturing as required by the appropriate government agencies. Each of these companies fracture stimulate a multitude of wells for the industry each year.

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We strive to minimize water usage in our fracture stimulation designs. Water recovered from our hydraulic fracturing operations is disposed of in a way that does not impact surface waters. We dispose of our recovered water by means of approved disposal or injection wells.

Surface spills and leaks are controlled, contained and remediated in accordance with the applicable requirements of state oil and gas commissions, as well as any Spill Prevention, Control and Countermeasures (SPCC) plans we maintain in accordance with EPA requirements. This would include any action up to and including total abandonment of the wellbore.

Other laws

The Oil Pollution Act of 1990, as amended, ("OPA") establishes strict liability for owners and operators of facilities that are the site of a release of oil into waters of the U.S. The OPA and its associated regulations impose a variety of requirements on responsible parties related to the prevention of oil spills and liability for damages resulting from such spills. A "responsible party" under the OPA includes owners and operators of certain onshore facilities from which a release may affect waters of the U.S. The OPA assigns liability to each responsible party for oil cleanup costs and a variety of public and private damages. While liability limits apply in some circumstances, a party cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct or resulted from violation of a federal safety, construction or operating regulation. If the party fails to report a spill or to cooperate fully in the cleanup, liability limits likewise do not apply. Few defenses exist to the liability imposed by the OPA. The OPA imposes ongoing requirements on a responsible party, including the preparation of oil spill response plans and proof of financial responsibility to cover environmental cleanup and restoration costs that could be incurred in connection with an oil spill.

The National Environmental Policy Act of 1969, as amended ("NEPA"), requires federal agencies to evaluate major agency actions having the potential to significantly impact the environment before their commencement. Generally, federal agencies must prepare either an environmental assessment or an environmental impact statement depending on whether the specific circumstances surrounding the proposed federal action will have a significant impact on the environment. The NEPA process involves public input through comments which can alter the nature of a proposed project either by limiting the scope of the project or requiring resource-specific mitigation. NEPA decisions can be appealed through the administrative and federal court systems by process participants. Although we believe that our actions do not typically trigger NEPA analysis, should we ever be subject to NEPA, the process may result in delaying the permitting and development of projects, increase the costs of permitting and developing some facilities and could result in certain instances in the cancellation of certain leases.

Our properties located in Colorado are subject to the authority of the Colorado Oil and Gas Conservation Commission, or COGCC. The COGCC recently approved new rules governing oil and gas activity which are intended to prevent or mitigate environmental impacts of oil and gas development and include the permitting of wells. Depending on how these and any other new rules are applied to our operations, they could add substantial increases in well costs in our Colorado operations. The rules could also impact the ability and extend the time necessary to obtain drilling permits, which creates substantial uncertainty about our ability to meet future drilling plans and thus production and capital expenditure targets.

Employees

At April 30, 2011, we had approximately 65 full-time employees. None of our employees is represented by a labor union or covered by any collective bargaining agreement. We believe that our relations with our employees are satisfactory.

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Legal Proceedings

From time to time, we are subject to legal proceedings and claims that arise in the ordinary course of business. Like other gas and oil producers and marketers, our operations are subject to extensive and rapidly changing federal and state environmental, health and safety and other laws and regulations governing air emissions, wastewater discharges, and solid and hazardous waste management activities. As of the date of this prospectus, there are no material pending or overtly threatened legal actions that we are aware of.

Insurance Matters

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

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MANAGEMENT

The following table sets forth information regarding our directors and executive officers as of the date of this prospectus and upon completion of the offering. There are no family relationships among any of our directors or executive officers.

Name	Age	Position
Michael R. Starzer	50	Director, President and Chief Executive Officer
Steven R. Enger	52	Executive Vice President and Chief Financial Officer
Steven B. Wilson	48	Vice President and Chief Accounting Officer
Gary A. Grove	50	Director, Executive Vice President Engineering and Planning, Interim Chief Operating Officer
Patrick A. Graham	50	Executive Vice President Corporate Development
Richard J. Carty	42	Chairman of the Board
James R. Casperson	63	Director
Marvin Chronister	60	Director
Kevin A. Neveu	50	Director
Todd A. Overbergen	45	Director

Michael R. Starzer is a member of our board of directors and is our President and Chief Executive Officer. Mr. Starzer was a founder and co-manager of Bonanza Creek Oil Company, LLC, and served as a member of the board of managers and President and Chief Executive Officer of our predecessor BCEC since BCEC's formation in 2006. Mr. Starzer has over 28 years of experience in the oil and gas industry. Mr. Starzer has served in numerous positions in the oil and gas industry evaluating and developing oil, gas, electricity and geothermal resources. From 1983 to 1991, Mr. Starzer was employed by Unocal in various engineering and supervisory positions. From 1991 until 1993, Mr. Starzer served with the California State Lands Commission as Statewide Petroleum Reservoir Engineer and worked as a private consultant to the energy industry supervising operations and appraisals of oil, gas and geothermal resources on properties throughout the United States. In 1993, Mr. Starzer returned to Unocal as an Asset Manager assisting them with the sale and management of certain assets. Starting in 1995, Mr. Starzer served as an Officer, Manager and Vice President of Berry Petroleum until beginning his tenure with one of our predecessors in 1999. Mr. Starzer holds a degree in Petroleum Engineering from the Colorado School of Mines and a Master of Science degree in Engineering Management from the University of Alaska and is a registered professional engineer in petroleum engineering. We believe Mr. Starzer's extensive experience in the oil and gas industry, his leadership positions at other oil and gas companies and his knowledge regarding our business and operations bring important experience and leadership to our company and our board of directors.

Steven R. Enger joined us on June 13, 2011, as Executive Vice President and Chief Financial Officer. Mr. Enger has over 30 years experience in the oil and gas industry. From August 2007 through August 2010, Mr. Enger served in a number of executive roles at Ellora Energy, an independent oil and gas exploration and production company. From August 2007 until March 2008, he was Vice President of Investor Relations and Corporate Development. He served as Executive Vice President and Chief Financial Officer from March 2008 until July 2009 and then was President and Chief Operating Officer until the sale of Ellora to ExxonMobil in August 2010. From 1997 until 2007, Mr. Enger was an analyst and Research Director with Petrie Parkman & Co., an investment banking and advisory firm focused on the energy industry, where he covered integrated oil exploration and production companies and performed oil markets analysis. Prior to Mr. Enger's tenure at Petrie Parkman, he worked for 16 years at ARCO in engineering, strategic planning and investor relations. Mr. Enger holds a B.S. in Petroleum Engineering from Colorado School of Mines and an MBA from UCLA. He is a member of the Society of Petroleum Engineers and the National Association of Petroleum Investment Analysts, where he formerly served on the Board of Directors and as President.

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Steven B. Wilson joined our company in June 2009 and is our Chief Accounting Officer and Vice President. His previous positions include serving as our Vice President and Chief Financial Officer and prior to that, as our Vice President of Finance Treasurer. Mr. Wilson served as Treasurer for Berry Petroleum Company from March 2007 through May 2009. Mr. Wilson also served as Controller and Assistant Controller for Berry Petroleum from November 2003 to February 2007. Mr. Wilson holds a Bachelor of Science degree in Accounting from Brigham Young University. Mr. Wilson is a CPA and was employed for eight years at Price Waterhouse LLP achieving the position of Audit Manager.

Gary A. Grove is a member of our board of directors and is our Executive Vice President Engineering and Planning and Interim Chief Operating Officer. Mr. Grove joined Bonanza Creek Oil Company in March 2003 and served as a member of the board of managers and as Executive Vice President and Chief Operating Officer of BCEC. Mr. Grove has over 29 years of experience in the oil and gas industry serving in reservoir engineering and management positions with UNOCAL and Nuevo Energy prior to joining us. Mr. Grove graduated from Marietta College in 1982 with a Bachelor of Science degree in Petroleum Engineering. Mr. Grove is an active member with the Society of Petroleum Engineers and has served in various capacities for student and local chapters since 1979. We believe Mr. Grove's extensive experience in the oil and gas industry and his knowledge regarding our business and operations brings important experience and leadership to the board of directors.

Patrick A. Graham joined Bonanza Creek Oil Company in November 2001, served as a Senior Vice President of BCEC and currently serves as our Executive Vice President Corporate Development. From 1995 to 2001, Mr. Graham was employed by Berry Petroleum Company where he evaluated acquisition opportunities in California, the Rocky Mountain region and Canada. Mr. Graham gained experience working with major and independent oil companies while employed with Dowell Schlumberger from 1986 to 1995. Mr. Graham received his Bachelors of Science degree in Petroleum Engineering from Texas A&M University and has held various technical positions in Utah, Colorado, New Mexico, California and Alaska.

Richard J. Carty was elected to our board of directors in December 2010 and is President of West Face Capital (USA) Corp, an affiliate of West Face Capital, a Toronto-based investment management firm, and has served on the board of directors of portfolio companies on behalf of West Face Capital. Prior to that time, Mr. Carty was a Managing Director of Morgan Stanley Principal Strategies in New York where he led the Special Situations, Strategic Investments, and Global Quantitative Equity investment teams. Mr. Carty was at Morgan Stanley & Co for 14 years in New York, and prior to that time was a partner at Gordon Capital Corp, a private Toronto-based investment bank for five years. We believe Mr. Carty's extensive asset management, capital markets, investment banking, and private equity experience bring important and valuable skills to the board of directors.

Todd A. Overbergen has served on the board of directors of our predecessor, BCEC, since 2008. Mr. Overbergen joined the D. E. Shaw Group in February 2004 and is Head of Energy and a Director in the Direct Capital Unit of the D. E. Shaw Group. From December 2000 to April 2003, Mr. Overbergen was a principal at Duke Capital Partners LLC, a merchant banking subsidiary of Duke Energy Corporation that provided mezzanine, equity, and senior debt capital to the energy industry. From 1998 to December 2000, Mr. Overbergen was a director in Arthur Andersen LLP's Global Corporate Finance group, where he co-led the national business services practice and provided investment banking services on mergers, acquisitions, and private market capital raising of debt and equity. Mr. Overbergen serves on the board of directors of numerous existing D. E. Shaw Group portfolio companies and has served on the board of directors of several previous portfolio companies of the D. E. Shaw Group and Duke Capital Partners LLC. Mr. Overbergen is a member of the Houston Producers Forum and Independent Petroleum Association of America. Mr. Overbergen holds two Bachelor of Business Administration degrees in finance and accounting from Texas A&M University. We believe Mr. Oberbergen's extensive financial, accounting, merchant banking and private equity experience, as well as his extensive experience in the energy sector, bring important and valuable skills to the board of directors.

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James R. Casperson was elected to our board of directors in March of 2011. Mr. Casperson has over 30 years of experience in the oil and gas industry and finance and accounting in the public and private sectors. Mr. Casperson is currently a private consultant to the energy industry. From 2005 until 2008, he was the Chief Financial Officer of Ellora Energy and, from 2000 until 2005, the Chief Financial Officer of Whiting Petroleum Corporation. Before joining Whiting, Mr. Casperson spent 15 years as President of Casperson Incorporated, a private consulting firm specializing in the energy industry. Mr. Casperson holds a BBA in Accounting from Texas Tech University. We believe Mr. Casperson's extensive experience in the oil and gas industry as well as his financial and accounting experience bring important and valuable skills to the board of directors.

Marvin Chronister was elected to our board of directors in March of 2011. Mr. Chronister has over 30 years experience in the oil and gas industry. Mr. Chronister is currently an independent investor, energy finance and operations consultant for Enfield Companies and on the Board of Sonde Resources Corp. From 2004 until 2006, Mr. Chronister was the Financial Operations Practice Director of Jefferson Wells International, Inc. He served as Managing Director of Corporate Finance for Deloitte & Touche from 1990 to 2003 with previous positions in industry and investment banking. Mr. Chronister holds a Bachelor of Business Administration degree from Stephen F. Austin State University. We believe Mr. Chronister's extensive experience in the oil and gas industry as well as his financial and accounting experience bring important and valuable skills to the board of directors.

Kevin A. Neveu was elected to our board of directors in March of 2011. Mr. Neveu has over 25 years of experience in the oil and gas industry. Currently, Mr. Neveu serves as a director, President and Chief Executive Officer of Precision Drilling Corporation. Mr. Neveu was previously President of the Rig Solutions Group of National Oilwell Varco, where he was responsible for the company's drilling equipment business. Beginning in 1982, Mr. Neveu held senior management positions with National Oilwell Varco and its predecessor companies in London, Moscow, Houston, Edmonton and Calgary. Mr. Neveu holds a Bachelor of Science degree and is a graduate of the Faculty of Engineering at the University of Alberta. Mr. Neveu is a Professional Engineer, as designated by the Association of Professional Engineers, Geologists and Geophysicists of Alberta and has attended the Advanced Management Program at the Harvard Business School. Mr. Neveu serves on the boards of RigNet Inc., the Heart and Stroke Foundation of Alberta and the International Association of Drilling Contractors. We believe Mr. Neveu's extensive experience in the oil and gas industry as well as his experience on the boards of directors of public energy companies bring substantial leadership and experience to the board of directors.

Board of Directors

Our board of directors currently consists of seven members, including our President and Chief Executive Officer and our Executive Vice President Engineering and Planning and Interim Chief Operating Officer. Each of our current directors has significant industry experience.

We also expect that our board will review the independence of our current directors using the independence standards of the NYSE, and we expect that our board of directors will consist of seven members within one year after the completion of this offering, a majority of whom will be independent.

West Face Capital and AIMCo, on behalf of certain of its clients, have entered into an investment management agreement by 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 more than 50% of the voting power for the election of directors, and as such, we are a "controlled company" as that term is defined in Section 303A of the NYSE Listed Company Manual. This investment management agreement 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."

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Under the NYSE rules, a "controlled company" may elect not to comply with certain NYSE corporate governance requirements, including: (1) the requirement that a majority of our board of directors consist of independent directors, (2) 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 (3) the requirement that our compensation committee be composed entirely of independent directors with a written charter addressing the Committee's purpose and responsibilities. While these requirements will not apply to us as long as we remain a "controlled company," we expect that our board of directors will continue to consist of a majority of independent directors and that our nominating and governance committee and compensation committee will consist entirely of independent directors within one year following the completion of this offering. Our nominating and governance committee and compensation committee each has a written charter addressing such committee's purpose and responsibilities.

In evaluating director candidates, we will assess whether a candidate possesses the integrity, judgment, knowledge, experience, skills and expertise that are likely to enhance the board's ability to manage and direct the affairs and business of the company, including, when applicable, to enhance the ability of committees of the board to fulfill their duties.

Committees of the Board of Directors

Our board of directors currently has an audit committee, compensation committee, reserve committee and environmental safety and regulatory compliance committee, and will have a nominating and governance committee upon consummation of this offering, and may have such other committees as the board of directors shall determine from time to time. Each of the standing committees of the board of directors will have the composition and responsibilities described below.

Audit Committee

The members of our audit committee are Messrs. Casperson (Chairman), Carty and Chronister, each of whom our board of directors has determined is financially literate. Our board of directors has determined that Messrs. Casperson and Chronister are audit committee financial experts and are "independent" under the standards of the NYSE and SEC regulations. This committee oversees, reviews, acts on and reports on various auditing and accounting matters to our board of directors, including: the selection of our independent accountants, the scope of our annual audits, fees to be paid to the independent accountants, the performance of our independent accountants and our accounting practices. In addition, the audit committee oversees our compliance programs relating to legal and regulatory requirements. We have adopted an audit committee charter defining the committee's primary duties in a manner consistent with the rules of the SEC and NYSE or market standards.

Compensation Committee

The members of our compensation committee are Messrs. Carty (Chairman), Neveu and Overbergen. Our board of directors has determined that Mr. Neveu is independent under the standards of the NYSE and SEC regulations. This committee establishes salaries, incentives and other forms of compensation for officers and other employees. Our compensation committee also administers our incentive compensation and benefit plans. We have adopted a compensation committee charter defining the committee's primary duties in a manner consistent with the rules of the SEC and NYSE or market standards.

Nominating and Corporate Governance Committee

Prior to the consummation of this offering, we will form a nominating and governance committee. This committee will identify, evaluate and recommend qualified nominees to serve on our board of directors, develop and oversee our internal corporate governance processes and maintain a management

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succession plan. In connection with the formation of a nominating and governance committee, we will adopt a nominating and governance committee charter defining the committee's primary duties in a manner consistent with the rules of the SEC and NYSE or market standards.

Reserve Committee

The members of the reserve committee are Messrs. Casperson (Chairman), Chronister and Overbergen. Our reserve committee oversees, reviews, acts on and reports on our reserve engineering reports and reserve engineers to our board. Our reserve committee is responsible for (i) the integrity of our reserve reports, (ii) determinations regarding the qualifications and independence of our independent reserve engineers, (iii) the performance of our independent reserve engineers and (iv) our compliance with certain legal and regulatory requirements.

Environmental Safety and Regulatory Compliance Committee

The members of the environmental safety & regulatory compliance ("ES&RC") committee are Messrs. Chronister (Chairman), Neveu and Grove. Our ES&RC committee's primary purpose is to assist our board of directors in fulfilling our responsibilities to provide global oversight and support of the Company's environmental safety, regulatory and compliance policies, programs and initiatives. In carrying out its responsibilities, the ES&RC committee reviews the status of our health, safety and environmental performance, including processes monitoring and reporting on compliance with internal policies and goals and applicable laws and regulations.

Compensation Committee Interlocks and Insider Participation

No member of our compensation committee has been at any time an employee of ours. During the past fiscal year, none of our executive officers serve or has served on the board of directors or compensation committee of a company that has one or more executive officers who serve on our board of directors or compensation committee. No member of our board of directors is an executive officer of a company in which one or more of our executive officers serves as a member of the board of directors or compensation committee of that company.

To the extent any members of our compensation committee and affiliates of theirs have participated in transactions with us, a description of those transactions is described in "*Certain Relationships and Related Party Transactions*."

Code of Business Conduct and Ethics

Our board of directors has adopted a code of business conduct and ethics applicable to our employees, directors and officers, in accordance with applicable U.S. federal securities laws and the corporate governance rules of the NYSE. Any waiver of this code may be made only by our board of directors and will be promptly disclosed as required by applicable U.S. federal securities laws and the corporate governance rules of the NYSE.

Corporate Governance Guidelines

Our board of directors has adopted corporate governance guidelines in accordance with the corporate governance rules of the NYSE.

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EXECUTIVE COMPENSATION AND OTHER INFORMATION

Compensation Discussion and Analysis

This compensation discussion and analysis, or CD&A, provides information about our compensation objectives and policies for our principal executive officer, our principal financial officer and our other three most highly compensated executive officers at the end of the last completed fiscal year, and is intended to place in perspective the information contained in the executive compensation tables that follow this discussion. This CD&A provides a general description of our compensation program and information about its various components.

Throughout this discussion, the following individuals are referred to as the "named executive officers" and are included in the Summary Compensation Table:

- Michael R. Starzer, President and Chief Executive Officer;
- Steven R. Enger, Executive Vice President and Chief Financial Officer;
- Steven B. Wilson, Vice President and Chief Accounting Officer;
- C. Stephen Black, our former Executive Vice President and Chief Operating Officer;
- Gary A. Grove, Executive Vice President Engineering and Planning and Interim Chief Operating Officer; and
- Patrick A. Graham, Executive Vice President Corporate Development.

Mr. Black resigned his position as Chief Operating Officer on May 20, 2011 to spend more time with his family. Information regarding Mr. Black's compensation is included in this CD&A and the accompanying tables and narrative sections because he was one of our named executive officers as of December 31, 2010. Our board of directors has appointed Mr. Grove to serve as interim Chief Operating Officer and has authorized a search committee comprised of three directors to identify qualified candidates to serve as our Chief Operating Officer. We expect that our board of directors will thoroughly assess all candidates presented by the search committee and will appoint a permanent Chief Operating Officer as soon as practicable.

Mr. Enger joined our company on June 13, 2011. Information regarding Mr. Enger's compensation is included in this CD&A because he will be a named executive officer for 2011 and thereafter.

Although the information presented in this CD&A focuses on our fiscal year 2010, we also describe compensation actions taken before or after fiscal year 2010 to the extent such discussion enhances the understanding of our executive compensation disclosure. Contemporaneous with this offering, we expect that certain of our current compensation plans and agreements with our named executive officers will be terminated or amended and that we will enter into new compensation plans and agreements to take effect upon consummation of this offering as discussed below.

Compensation Program Philosophy and Objectives

The objective of our compensation program is to attract, retain and motivate the most qualified individuals in the oil and gas industry who we can identify and recruit. Our compensation program is designed to reward employees for performance that creates long-term stockholder value by successfully implementing our long-term strategy and achieving our short-term goals. We strive to create a compensation program that encourages long-term value creation by tying individual compensation to the attainment of our annual performance targets while acknowledging and fostering the unique qualifications, skills, experience and responsibilities of each individual.

For 2010, as a private company, we did not have a compensation committee, compensation consultant or formally set peer group, however, our compensation was set based on our board of directors' and

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management's assessment of a variety of factors, including industry information and performance, an individual's rank, tenure, experience and job responsibilities and the performance of our company. For 2011, we have begun to establish more formal compensation standards using compensation levels at or near the market midpoint, or 50^{th} percentile, of our peer group as a guideline in establishing our compensation levels, although we may deviate from the 50^{th} percentile for individual considerations such as experience, tenure and job responsibilities. While historically long term incentives have played a relatively small role in the annual compensation of our named executive officers, after this offering, consistent with our philosophy of setting compensation levels at or near the 50^{th} percentile of our peer group, we intend to implement a Long-term Incentive Plan. See "*Elements of Compensation and Why We Pay Each Element Long-term Incentives*" below. Under this Long-term Incentive Plan, we expect that a significant portion of our named executive officers' overall compensation will be made up of long-term incentives. The average portion of total compensation paid as long-term incentives for the named executive officers at the 50^{th} percentile of our peer group is approximately 40%. For 2011, the compensation for all named executive officers is reviewed and determined by our compensation committee, subject to the approval of our board of directors. In addition to actual job responsibility and competitive market data, we give consideration to individual performance of the named executive officer and internal pay equity relative to our other executive officers. Under the direction of our compensation committee and subject to the approval of our board, salaries are generally reviewed annually as part of our performance review process.

Setting Executive Officer Compensation

The Role of Our Compensation Committee: For 2010 and prior years, as a private company, our board of directors and management set executive officer compensation taking into account a variety of factors, including industry information and performance, an individual's rank, tenure, experience and job responsibilities and the performance of our company. For the fiscal year 2010, we did not have a compensation committee. Our board of directors established the compensation committee in March of 2011 and authorized the committee to review and propose for approval by our board of directors the compensation for our Section 16(b) executives. Our compensation committee (i) oversees our compensation programs on behalf of our board of directors; (ii) is responsible for proposing programs for approval by our board of directors that attract, retain and motivate qualified executive-level talent; and (iii) monitors our compensation programs and strives to ensure that the total compensation paid to the named executive officers is fair, reasonable and competitive with that provided to executive officers serving in similar roles and with similar responsibilities in other U.S. publicly traded energy companies.

The Role of the Compensation Consultant: For the fiscal year 2011, Longnecker & Associates (the "Compensation Consultant") was engaged on behalf of the compensation committee as our compensation committee's independent compensation consultant. Our predecessor did not engage a compensation consultant. Our compensation committee felt it was beneficial to have an independent third-party analysis to assist in evaluating and setting executive compensation. Our compensation committee chose the Compensation Consultant because our compensation committee believes the Compensation Consultant has extensive experience in providing executive compensation advice, including specific experience in the oil and gas industry. The Compensation Consultant provided our compensation committee with an analysis of our executive compensation programs, including total direct compensation comprised of base salary, annual incentive and long-term incentive compensation, in order to assess the competitiveness of our programs and to provide conclusions and recommendations. For fiscal 2011, our compensation committee will take into consideration the discussions, guidance and compensation studies produced by the Compensation Consultant in order to make compensation decisions. The Compensation Consultant does not provide to us any services or advice on matters unrelated to executive and independent director compensation and reports directly to and takes direction from our compensation committee, which has the authority to engage or terminate the Compensation Consultant in its discretion. Our compensation committee has determined that the advice provided by the Compensation Consultant relating to executive

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compensation was free from any relationships that could impair the professional advice or compromise the integrity of the information or data provided to our compensation committee.

Competitive Benchmarking and Peer Group: Our compensation committee considers competitive industry data in making executive pay determinations. Pursuant to our compensation committee's decision to maintain a peer group for compensation purposes and in view of evolving industry and competitive conditions, the Compensation Consultant proposed certain peer group companies for our compensation committee's review. As a private company, neither we nor our predecessor utilized a formal peer group, but our board of directors and management considered industry information and performance, an individual's rank, tenure, experience and job responsibilities and the performance of our company in setting compensation.

After discussions with the Compensation Consultant and reviewing the Compensation Consultant's recommendation of a peer group based on companies with annual revenue, assets, and net income similar to ours taking into account geographic footprint and employee count, our compensation committee determined that the peer group listed below is the most appropriate for purposes of executive compensation analyses. The Compensation Consultant compiled compensation data for the peer group from a variety of sources, including proxy statements and other publicly filed documents and published survey compensation data from multiple sources, including the Economic Research Institute, Mercer and Towers Watson. This compensation data was then used to compare the compensation of our named executive officers to our peer group where the peer group had individuals serving in similar positions.

Peer Group:

Brigham Exploration Company

Contango Oil & Gas Company

Endeavour International Corporation

Georesources, Inc.

Gulfport Energy Corporation

Oasis Petroleum Inc.

Petroquest Energy, Inc.

Ram Energy Resources, Inc.

Resolute Energy Corporation

Rex Energy Corporation

Warren Resources, Inc.

While the Compensation Consultant makes recommendations to our compensation committee on compensation, our compensation committee has full discretion to act and implement compensation decisions independent of the Compensation Consultant's recommendations.

Elements of Our Compensation and Why We Pay Each Element

From our inception, our executive compensation program has consisted primarily of base salary, bonus payments, equity-based incentives, severance and change-in-control benefits, certain perquisites and employee benefits provided to certain of our executive officers. Our compensation committee, assisted by the Compensation Consultant, is currently developing compensation programs that are intended to take effect upon or shortly after consummation of this offering and to provide our named executive officers with an overall compensation package suitable to executives of a similarly situated publicly traded company,

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subject to approval by our board of directors. Although our compensation committee has not yet determined the precise components of these compensation programs, we expect that these programs for our named executive officers will consist of five elements: base salary, annual performance-based cash incentive compensation, equity-based compensation, severance and change-in-control benefits and other employee benefits.

Base Salary: Base salary is the fixed annual compensation we pay to each of our named executive officers for carrying out their specific job responsibilities. Base salaries are a major component of the total annual cash compensation paid to our named executive officers. Base salaries are determined after taking into account many factors, including the following:

- the responsibilities of the officer, the level of experience and expertise required for the position and the strategic impact of the position;

- the need to recognize each officer's unique value and demonstrated individual contribution, as well as future contributions; and

- salaries paid for comparable positions in similarly-situated companies.

For 2010, base salaries were determined by our board of directors and management based on industry information and performance, an individual's rank, tenure, experience and job responsibilities and the performance of our company. For 2010, base salaries for our named executive officers increased by nominal amounts for market and cost of living reasons, except in the case of Steve Black, whose increase was due to his promotion to Chief Operating Officer.

The Compensation Consultant has provided our compensation committee with an analysis of the base salaries paid to our executive officers in 2010 in comparison to comparable market salaries of our peer group. Based on the Compensation Consultant's analysis, our compensation committee concluded that the aggregate base salaries of our executives were at or near the market 25^{th} percentile, which is below the market 50^{th} percentile that our compensation committee has determined to be the level necessary to remain competitive with other companies in our peer group reflecting our status as a private company. Accordingly, our compensation committee recently recommended and our board of directors approved an increase in the base salaries of certain of our named executive officers in order to set their base salaries closer to the market 50^{th} percentile with appropriate adjustments for level of experience and job responsibility. The following table shows the base salaries for each of our named executive officers (i) in

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effect for 2011, (ii) effective as of June 1, 2010 and (iii) at the 50th percentile of our peer group for such position.

Name and Position	2010 Base Salary	2011 Base Salary (effective 6/1/2011)	Salary for 50th Percentile of Peer Group
Michael R. Starzer, President and Chief Executive Officer	$ 275,018	$ 326,000	$ 447,437
Steven R. Enger, Executive Vice President and Chief Financial Officer(1)	n/a	$ 260,000	$ 259,892
C. Stephen Black, Chief Operating Officer(2)	$ 261,538	$ 262,500	$ 273,092
Gary A. Grove, Executive Vice President Engineering and Planning and Interim Chief Operating Officer	$ 225,014	$ 240,000	$ 230,458
Patrick A. Graham, Executive Vice President Corporate Development	$ 180,003	$ 215,000	$ 237,800

(1) Mr. Enger began his employment with our company on June 13, 2011. His salary shown above is effective as of such date. Prior to joining us as Chief Financial Officer, Mr. Enger was a consultant to the company for which he was paid $25,000 in the aggregate for 2011.

(2) Mr. Black resigned his position as Chief Operating Officer on May 20, 2011 to spend more time with his family. The 2011 salary shown above represents a full year of Mr. Black's salary as in effect on his departure date.

Annual Cash Incentive Compensation: All of our employees, including our named executive officers, are eligible to receive performance-based cash bonuses. For 2010, our bonuses were discretionary and, for the first quarter of 2010, paid quarterly. After the first quarter of 2010, the company discontinued the quarterly bonus practice. Discretionary bonus amounts for the first quarter of 2010 were based on each employee's, including each of our named executive officer's rank, contributions and performance. Management has historically utilized the aggregate bonus levels paid out by our peers relative to the EBITDAX levels generated each year by those peers as a comparative tool to recommend aggregate bonus levels to our board of directors for approval. The bonus amount approved by our board of directors and paid to employees was entirely discretionary but typically varied between 0.5% and 5% of EBITDAX generated for that year. In 2010, the aggregate bonus level paid to employees represented approximately 1% of EBITDAX generated by the Company. For 2010, Mr. Wilson and Mr. Grove received the largest bonuses for their efforts in refinancing our debt position and achieving strong reserve bookings in 2009, respectively. The amounts received by our named executive officers in 2010 as discretionary bonuses are shown below under "*Summary Compensation Table.*" In lieu of an annual 2010 bonus, in early 2011, we paid a $500,000 aggregate bonus in connection with the Corporate Restructuring. Bonus amounts for this transaction bonus were determined based on each employee's contribution, as determined by management and our board of directors, to the Corporate Restructuring and as a percentage of their 2010 salary. With respect to the $500,000 transaction bonus in connection with the Corporate Restructuring, Mr. Starzer received $58,000, Mr. Black received $56,000, Mr. Grove received $58,000, Mr. Graham received $38,000 and Mr. Wilson received $20,000.

For fiscal year 2011, subject to approval by our board of directors, the compensation committee has discretionary authority to identify the employees entitled to receive an award for the fiscal year and to determine the amount of such award based on performance criteria established by our compensation committee.

We anticipate that our compensation committee will propose for approval by our board of directors an annual performance-based cash incentive, or bonus plan, to take effect upon or shortly after

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consummation of this offering. We expect that the plan proposed by the compensation committee will provide for variable cash compensation earned when established performance objectives are achieved. Such a plan will likely be designed to reward plan participants, including the named executive officers, who have achieved certain corporate and individual performance objectives. Performance criteria may include operational, financial and other performance measures, such as production, safety, retention and individual job-related targets as determined, in the case of our named executive officers, at the discretion of our compensation committee and our board of directors.

Such bonus plan will be included as part of our compensation program because we believe this element of compensation will help us to:

- motivate management to achieve key short-term corporate goals; and
- align executives' interests with stockholders' interests.

Long-term Incentives: In connection with our Corporate Restructuring, we adopted the Management Incentive Plan which we refer to as the MIP. Under the MIP, 10,000 shares of our Class B Common Stock were reserved for issuance in connection with restricted stock awards to our management and employees. Upon the consummation of our Corporate Restructuring on December 23, 2010, 7,500 restricted shares of our Class B Common Stock were granted to our named executive officers as follows: 2,500 to Mr. Starzer, 2,000 to Mr. Grove and 1,500 to each of Messrs. Black and Graham. Mr. Black subsequently forfeited his 1,500 restricted shares of Class B Common Stock upon his resignation and separation from the company. The size of these share grants was determined as a result of negotiations between management and our principal stockholder at the time of our Corporate Restructuring. On June 30, 2011, in connection with his employment, Mr. Enger received a grant of 600 shares of Class B Common Stock. All Class B Common Stock has been granted pursuant to Restricted Stock Agreements and, upon consummation of this offering, is subject to a three-year vesting period whereby the Class B Common Stock granted to each individual vests in one third increments annually commencing on the consummation of this offering, provided that such individual remains employed by the company. We feel that the vesting provisions of the Class B Common Stock under the MIP are sufficient to encourage our senior management to produce long-term stockholder value. We intend to grant the 3,400 available restricted shares of Class B Common Stock to our management and employees prior to consummation of this offering with each such individual grant based on rank, tenure, performance and contribution to the company. Upon consummation of this offering, all 10,000 restricted shares of Class B Common Stock under the MIP will be converted into our Class A Common Stock. See "*Certain Relationships and Related Party Transactions Class B Common Stock Conversion*."

We expect that our compensation committee will propose and that our board of directors will approve a Long Term Incentive Plan, or LTIP, to take effect upon or shortly after the consummation of this offering. This LTIP will replace the MIP for equity incentives to be granted following the consummation of this offering. The purpose of our LTIP will be to attract and retain the best available personnel for positions of substantial responsibility, to provide additional incentives to our employees, directors and consultants, and to promote the success of our business. We anticipate that our LTIP will provide for grants of (a) incentive stock options qualified as such under U.S. federal income tax laws, (b) stock options that do not qualify as incentive stock options, (c) stock appreciation rights ("SARs"), (d) restricted stock awards, (e) restricted stock units (f) performance awards or (g) other awards, including common stock awarded as a bonus, dividend equivalents, convertible or exchangeable debt securities and similar rights.

Our compensation committee believes long-term incentive-based equity compensation is an important component of our overall compensation program because it:

- Rewards the achievement of our long-term goals;
- Aligns our executives' interests with the long-term interests of our stockholders;

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- Encourages executive retention; and

- Conserves our cash resources.

We anticipate that our compensation committee will have the authority, subject to approval by our board of directors, to award incentive compensation under our LTIP to our named executive officers and others in such amounts and on such terms as our compensation committee determines appropriate in its discretion. In determining such awards, our compensation committee will review the Compensation Consultant's market analysis to determine the appropriate amount of equity to grant to our executive officers based on market data while also taking into consideration our performance, individual performance and retention concerns. Our named executive officers and other employees will be entitled to participate in our LTIP subject to certain restrictions. Our compensation philosophy is to use the 50^{th} percentile of our peer group as a guideline in terms of setting long term incentive compensation, which will be reflected in the size of the grants to our named executive officers under our LTIP. This philosophy is intended to attract, motivate and retain high caliber executive talent, while aligning executives' interests with those of our stockholders. The average portion of total compensation paid as long-term incentives for the named executive officers of our peer group is approximately 40%.

We do not expect that our LTIP will be subject to the Employee Retirement Income Security Act of 1974, as amended, or ERISA. For a limited period of time following this offering, we anticipate that our LTIP will qualify for an exception to the deductibility limitations imposed by Section 162(m) of the Internal Revenue Code of 1986, as amended ("Code"), assuming that certain requirements are met. We expect that during that limited period of time, awards under our LTIP will be exempt from the limitations on the deductibility of compensation that exceeds $1,000,000. See " *Accounting and Tax Considerations"* below.

Although the terms of any LTIP have not yet been determined by our board of directors, we expect that our LTIP will have the following general features (though any of these features may be changed in the final LTIP):

- provision for certain number of shares of our common stock reserved and available for delivery in connection with awards;

- eligibility for any individual who provides services to us, including non-employee directors and consultants, subject to any limitations provided for by our compensation committee or by the terms of our LTIP;

- administration by our compensation committee or as otherwise provided for by the terms of our LTIP;

- stock option grants to be issued with an exercise price not less than the fair market value per share as of the date of grant;

- SARs, each representing the right to receive an amount equal to the excess of the fair market value of one share of our common stock on the date of exercise over the grant price of the SAR (which grant price will not be less than the fair market value per share as of the date of grant);

- restricted stock awards granting shares of common stock subject to a risk of forfeiture, restrictions on transferability and any other restrictions imposed by the compensation committee in its discretion;

- restricted stock units consisting of rights to receive common stock, cash or a combination of both at the end of a specified period;

- authority granted to the compensation committee to designate certain awards under our LTIP as "performance awards," the grant, exercise or settlement of which is subject to the attainment of one or more performance goals; and

other awards related to common stock, subject to applicable legal limitations and the terms of our LTIP and its purposes, other awards related to common stock.

Other Employee Benefits: We expect that the named executive officers will continue to be eligible for the same health, welfare and other employee benefits available to our employees generally, including medical and dental insurance, short and long-term disability insurance and a 401(k) plan that includes company matching of 6% of each individual's cash earnings.

Stock Awards: In the fiscal year 2010, we issued 7,500 shares of our Class B Common Stock in the form of shares of restricted stock to our named executive officers, 1,500 of which were subsequently forfeited by Mr. Black upon his resignation. The share amounts were determined in connection with our Corporate Restructuring. In connection with the offering, all of the outstanding Class B Common Stock will automatically be converted into 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 anticipate issuing shares of our common stock upon conversion of the Class B Common Stock based on an assumed initial public offering price of $ (the midpoint of the price range set forth on the cover page of this prospectus).

Salary and Cash Incentive Awards in Proportion to Total Compensation: The following table sets forth the percentage of each named executive officer's total compensation that we paid in the form of base salary and annual cash incentive awards.

Name	Year	Percentage of Total Compensation Paid in Base Salary and Annual Incentive Awards
Michael R. Starzer	2010	95%
	2009	96%
	2008	97%
C. Stephen Black[(1)]	2010	94%
	2009	90%
	2008	80%
Steven B. Wilson	2010	95%
	2009	91%
	2008	
Gary A. Grove	2010	93%
	2009	90%
	2008	92%
Patrick A. Graham	2010	93%
	2009	89%
	2008	91%

(1) Mr. Black joined us in March 2008 and resigned effective as of May 20, 2011.

Employment Agreement and Severance and Change in Control Arrangements

In 2009, we entered into employment agreements with each of our named executive officers that provide for base salary, participation in our benefit plans, paid vacation and reimbursement of reasonable business expenses. Such agreements provide for 12 months base salary in a lump sum as severance in the event of a termination of such officer's employment by us without cause, by such officer for good reason, due to permanent disability of such officer or upon resignation of such officer in connection with a change of control of our company.

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In connection with our Corporate Restructuring, we amended and restated the employment agreements with Messrs. Starzer, Grove and Graham to provide for participation in the MIP. Mr. Enger entered into a similar employment agreement upon commencement of his employment with our company. Upon termination of employment by us without cause, by the named executive officer for good reason, due to permanent disability of the named executive officer or upon resignation in connection with a change in control of our company, such officer is entitled to (i) an immediate cash payment equal to 12 months base salary; (ii) a cash payment made within 70 days of termination, equal to 12 months base salary plus 200% (100% in Mr. Enger's case) of the two-year average bonuses paid to such officer; and (iii) for 18 months (12 months in Mr. Enger's case) following termination, monthly reimbursement of the difference between such officer's COBRA premiums and the amount our active senior executive employees pay for the same or similar coverage under our group health plan. Such named executive officers are entitled to receive these severance benefits only upon executing a general release. These amended and restated employment agreements include 2 year (1 year in Mr. Enger's case) post termination non-competition and non-solicitation clauses.

Contemporaneous with the consummation of this offering, we plan to amend and restate the existing employment agreements with our named executive officers, including the terms and conditions of employment and the severance and change in control benefits for our named executive officers. We also expect to adopt an executive change in control and severance benefit plan, to be effective as of or shortly after the consummation of this offering, which will provide severance and change in control benefits to participants. We believe that adoption of such an executive change in control and severance benefit plan is appropriate because we believe that the interests of our stockholders are best served if we provide separation benefits to eliminate, or at least reduce, the reluctance of executive officers and other key employees to pursue potential corporate transactions that may be in the best interests of our stockholders, but that may have resulting adverse consequences to the employment situations of our executive officers and other key employees. Further, such a plan will ensure an understanding of what benefits are to be paid to participants in the event of termination of their employment in certain specified circumstances and/or upon the occurrence of a change in control.

Stock Ownership Guidelines

Stock ownership guidelines have not been implemented for our named executive officers or directors. We will continue to periodically review best practices and reevaluate our position with respect to stock ownership guidelines in the future.

Accounting and Tax Considerations

Section 162(m) of the Code

Generally, Section 162(m) of the Code disallows a tax deduction to any publicly-held corporation for individual compensation in excess of $1,000,000 paid in any taxable year to any of its chief executive officer or other named executive officer, other than its chief financial officer, unless the compensation is performance-based. As we are not currently publicly traded, our board of directors and compensation committee have not previously taken the deductibility limit imposed by Section 162(m) of the Code into consideration in setting compensation.

Certain exceptions to the deductibility limitation apply for a limited period of time in the case of companies that become publicly-traded through an initial public offering, assuming certain conditions are satisfied. We expect that our arrangements will fit within that exception; however, we reserve the right to use our judgment to authorize compensation payments that do not comply with the performance-based compensation exemption in Section 162(m) of the Code when we believe that such payments are appropriate and in the best interest of our stockholders, after taking into consideration changing business conditions or the executive's individual performance and/or changes in specific job duties and responsibilities.

Section 409A of the Code

Section 409A of the Code requires that "nonqualified deferred compensation" be deferred and paid under plans or arrangements that satisfy the requirements of the statute with respect to the timing of deferral elections, timing of payments and certain other matters. Failure to satisfy these requirements can expose employees and other service providers to accelerated income tax liabilities and penalty taxes and interest on their vested compensation under such plans. Accordingly, as a general matter, it is our intention to design and administer our compensation and benefits plans and arrangements for all of our employees and other service providers, including our named executive officers, so that they are either exempt from, or satisfy the requirements of, Section 409A of the Code.

Section 280G of the Code

Section 280G of the Code disallows a tax deduction with respect to excess parachute payments to certain executives of companies which undergo a change in control. In addition, Section 4999 of the Code imposes a 20% excise tax on the individual with respect to the excess parachute payment. Parachute payments are compensation linked to or triggered by a change in control and may include, but are not limited to, bonus payments, severance payments, certain fringe benefits, and payments and acceleration of vesting from long-term incentive plans including stock options and other equity-based compensation. Excess parachute payments are parachute payments that exceed a threshold determined under Section 280G of the Code based on the executive's prior compensation. In approving the compensation arrangements for our named executive officers in the future, our compensation committee will consider all elements of the cost to the company of providing such compensation, including the potential impact of Section 280G of the Code. However, our compensation committee may, in its judgment, authorize compensation arrangements that could give rise to loss of deductibility under Section 280G of the Code and the imposition of excise taxes under Section 4999 of the Code when it believes that such arrangements are appropriate to attract and retain executive talent.

Our employment agreements with our officers, including our named executive officers, do not provide a "gross-up" or other reimbursement payment for any tax liability that such officer might owe as a result of the application of Sections 280G, 4999, or 409A of the Code and we have not agreed and are not otherwise obligated to provide any named executive officers with such a "gross-up" or other reimbursement. The employment agreements with Messrs. Starzer, Enger, Grove and Graham specify that if any severance payment to such individuals constitutes "parachute payment" (as defined under Section 280G of the Code), then either (i) such payment shall be reduced so that such payment is $1 less than the limitation under Section 280G or (ii) paid in full, whichever produces the better after tax result.

Accounting Standards

Financial Accounting Standards Board (FASB) Accounting Standards Codification, Topic 718, "Compensation Stock Compensation" (ASC Topic 718) requires us to recognize an expense for the fair value of equity-based compensation awards. Grants of stock options, restricted stock and other equity-based awards are accounted for under ASC Topic 718. Our compensation committee regularly considers the accounting implications of significant compensation decisions, especially in connection with decisions that relate to our equity incentive award plans and programs. As accounting standards change, we may revise certain programs to appropriately align accounting expenses of our equity awards with our overall executive compensation philosophy and objectives.

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Summary Compensation Table

The following table shows information concerning the annual compensation for services provided to us by our named executive officers during the fiscal years ended December 31, 2010, 2009 and 2008.

Name and Principal Position	Year	Salary	Bonus[1]	Stock Awards[2]	Non-Equity Incentive Plan Compensation	All Other Compensation[3]	Total
Michael R. Starzer	2010	$ 275,018	$ 4,000	$ 4,000		$ 9,993	$ 293,011
President and	2009	$ 261,342	$ 6,875			$ 11,205	$ 279,422
Chief Executive Officer	2008	$ 275,000	$ 55,700			$ 11,835	$ 342,535
C. Stephen Black[4]	2010	$ 261,538	$ 6,000	$ 2,400		$ 13,475	$ 283,413
Executive Vice President and	2009	$ 205,070	$ 7,031			$ 23,869	$ 235,970
Chief Operating Officer	2008	$ 137,500[5]	$ 26,600			$ 41,130	$ 205,230
Steven B. Wilson	2010	$ 196,543	$ 13,857			$ 12,139	$ 222,539
Vice President and Chief	2009	$ 85,371[6]	$ 4,600			$ 9,095	$ 99,066
Accounting Officer	2008	n/a	n/a			n/a	
Gary A. Grove	2010	$ 225,014	$ 15,192	$ 3,200		$ 14,184	$ 257,590
Executive Vice President	2009	$ 213,825	$ 15,000			$ 24,219	$ 253,044
Engineering and Planning and Interim Chief Operating Officer	2008	$ 211,536	$ 38,500			$ 21,362	$ 271,398
Patrick A. Graham	2010	$ 180,003	$ 9,040	$ 2,400		$ 11,342	$ 202,785
Executive Vice President	2009	$ 174,805	$ 21,950			$ 23,136	$ 219,891
Corporate Development	2008	$ 176,964	$ 43,500			$ 22,872	$ 243,336

(1) Values represent amounts received in 2010 under our discretionary bonus plan. See "*Annual Performance-Based Cash Incentive Compensation*" above.

(2) Amounts reflect the full grant-date fair value of restricted stock awards of our Class B Common Stock granted during 2010 computed in accordance with ASC Topic 718. Beginning with an assumed per share price of $12.52 for the Class A Common Stock, the price paid by the investors in our Corporate Restructuring, the conversion rate of the Class B Common Stock was calculated on a fair market value basis, utilizing the calculation provided in our amended and restated certificate of incorporation and internal financial projections to arrive at an expected Class A Common Stock share price as of the date of the grant which was discounted to present value using a weighted average cost of capital and for lack of control and marketability. A probability factor was added to weight the likelihood that a liquidity event would take place during the forecast period. In addition, following our Corporate Restructuring in connection with the dissolution of Bonanza Creek Energy Company, LLC (BCEC), Class B Units of BCEC held by Messrs. Starzer and Grove were redeemed by BCEC in exchange for 317,142 shares and 135,953 shares, respectively, of Class A Common Stock held by BCEC with an approximate fair value of $4.0 million and $1.7 million, respectively.

(3) Values represent each executives' 401(k) match by us for 2010.

(4) Mr. Black resigned for family reasons effective as of May 20, 2011.

(5) Mr. Black joined us in March 2008; full year 2008 salary would have been $200,000.

(6)

Mr. Wilson joined us in June 2009; full year 2009 salary would have been $175,000.

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Grants of Plan-Based Awards

The following table provides information concerning each grant of plan-based awards made to our named executive officers during the fiscal year ended December 31, 2010.

Name	Grant Date	All other stock awards; Number of shares of stock units(1)	Grant date fair value of stock awards(2)
Michael R. Starzer	12/23/10	2,500	$ 4,000
C. Stephen Black(3)	12/23/10	1,500	2,400
Gary A. Grove	12/23/10	2,000	3,200
Patrick A. Graham	12/23/10	1,500	2,400

(1) Consists of restricted shares of Class B Common Stock that, contemporaneously with this offering will be converted into restricted shares of our common stock pursuant to a formula set forth in our certificate of incorporation, of which we estimate that shares will be held by Mr. Starzer, shares will be held by Mr. Grove and shares will be held by Mr. Graham, based on an assumed initial public offering price of $ (the midpoint of the price range set forth on the cover page of this prospectus). Upon conversion of Mr. Enger's June 30, 2011 grant of 600 restricted shares of Class B Common Stock (grant date fair market value of $3,200), we estimate that Mr. Enger will hold shares of our common stock, based on an assumed initial public offering price of $ (the midpoint of the price range set forth on the cover page of this prospectus). After the offering, these restricted shares of our common stock will be subject to a three-year vesting period whereby the Class B Common Stock granted to each individual vests in one-third increments annually commencing on the consummation of this offering. See "*Certain Relationships and Related Party Transactions Class B Common Stock Conversion*."

(2) Amounts reflect the full grant-date fair value of restricted stock awards of our Class B Common Stock granted during 2010 computed in accordance with ASC Topic 718. Beginning with an assumed per share price of $12.52 for the Class A Common Stock, the price paid by the investors in our Corporate Restructuring, the conversion rate of the Class B Common Stock was calculated on a fair market value basis, utilizing the calculation provided in our amended and restated certificate of incorporation and internal financial projections to arrive at an expected Class A Common Stock share price as of the date of the grant which was discounted to present value using a weighted average cost of capital and for lack of control and marketability. A probability factor was added to weight the likelihood that a liquidity event would take place during the forecast period. In addition, following our Corporate Restructuring in connection with the dissolution of BCEC, Class B Units of BCEC held by Messrs. Starzer and Grove were redeemed by BCEC in exchange for 317,142 shares and 135,953 shares, respectively, of Class A Common Stock held by BCEC with an approximate fair value of $4.0 million and $1.7 million, respectively.

(3) Mr. Black resigned effective as of May 20, 2011, at which time his stock award of 1,500 restricted shares of Class B Common Stock was forfeited.

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Outstanding Equity Awards at Fiscal Year End

The following table sets forth certain information with respect to the outstanding stock awards held by the named executive officers at the end of fiscal year 2010.

Name	Grant Date	Number of shares of stock that have not vested[(1)]	Market Value of shares of stock that have not vested[(2)]
Michael R. Starzer	12/23/10	2,500	$ 4,000
C. Stephen Black[(3)]	12/23/10	1,500	2,400
Gary A. Grove	12/23/10	2,000	3,200
Patrick A. Graham	12/23/10	1,500	2,400

(1) Consists of restricted shares of Class B Common Stock that, contemporaneously with this offering, will be converted into restricted shares of our common stock pursuant to a formula set forth in our certificate of incorporation, of which we estimate that shares will be held by Mr. Starzer, shares will be held by Mr. Grove and shares will be held by Mr. Graham, assuming an initial public offering price of $ per share (the midpoint of the price range set forth on the cover page of this prospectus). Upon conversion of Mr. Enger's June 30, 2011 grant of 600 restricted shares of Class B Common Stock, we estimate that Mr. Enger will hold shares of our common stock, based on an assumed initial public offering price of $ (the midpoint of the price range set forth on the cover page of this prospectus). After the offering, these restricted shares of will be subject to a three-year vesting period whereby the Class B Common Stock granted to each individual vests in one-third increments annually commencing on the consummation of this offering. See "*Certain Relationships and Related Party Transactions Class B Common Stock Conversion*."

(2) Amounts reflect the full grant-date fair value of restricted stock awards of our Class B Common Stock granted during 2010 computed in accordance with ASC Topic 718. Beginning with an assumed per share price of $12.52 for the Class A Common Stock, the price paid by the investors in our Corporate Restructuring, the conversion rate of the Class B Common Stock was calculated on a fair market value basis, utilizing the calculation provided in our amended and restated certificate of incorporation and internal financial projections to arrive at an expected Class A Common Stock share price as of the date of the grant which was discounted to present value using a weighted average cost of capital and for lack of control and marketability. A probability factor was added to weight the likelihood that a liquidity event would take place during the forecast period. In addition, following our Corporate Restructuring in connection with the dissolution of BCEC, Class B Units of BCEC held by Messrs. Starzer and Grove were redeemed by BCEC in exchange for 317,142 shares and 135,953 shares, respectively, of Class A Common Stock held by BCEC with an approximate fair value of $4.0 million and $1.7 million, respectively.

(3) Mr. Black resigned effective as of May 20, 2011, at which time his stock award of 1,500 restricted shares of Class B Common Stock was forfeited.

Potential Payments upon Termination or Change of Control

The table below discloses a hypothetical amount of compensation and/or benefits due to the named executive officers in the event of their termination of employment and/or in the event we undergo a change in control. The amounts disclosed assume such termination and/or such change of control was effective as

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of December 31, 2010. The amounts below constitute estimates of the amounts that would be paid to the named executive officers upon termination of their employment and/or upon a change in control. The actual amounts to be paid are dependent on various factors, which may or may not exist at the time a named executive officer is actually terminated and/or a change in control actually occurs. Therefore, such amounts and disclosures should be considered "forward looking statements."

			Reason for Termination	
Name	**Payment**	**For Cause, Resignation Without Good Reason or Death**	**Without Cause, Resignation for Good Reason or Expiration of Agreement or Disability**	**Change in Control(1)**
Michael R. Starzer	Cash Severance		$ 550,000	$ 550,000
	Bonus Payment		10,875	10,875
	Stock Award(2)			
	Health Payment		14,315	14,315
Total			$ 575,190	$ 575,190
C. Stephen Black(3)	Cash Severance		$ 420,000	$ 420,000
	Bonus Payment		12,000	12,000
	Stock Award(2)			
	Health Payment		14,315	14,315
Total			$ 446,315	$ 446,315
Steven B. Wilson	Cash Severance		$ 210,000	$ 210,000
	Bonus Payment			
	Stock Award			
	Health Payment			
Total			$ 210,000	$ 210,000
Gary A. Grove	Cash Severance		$ 450,000	$ 450,000
	Bonus Payment		30,192	30,192
	Stock Award(2)			
	COBRA Premium		14,315	14,315
Total			$ 494,507	$ 494,507
Patrick A. Graham	Cash Severance		$ 360,000	$ 360,000
	Bonus Payment		30,990	30,990
	Stock Award(2)			
	Health Payment		14,315	14,315
Total			$ 405,305	$ 405,305

(1) In the case of Messrs. Starzer, Grove and Graham, the severance payment is contingent upon resignation within 30 days following the six-month anniversary of the change in control. In the case of Mr. Wilson, the severance payment is contingent upon resignation within three months following the change in control.

(2) Upon termination without cause, resignation for good reason, death or permanent disability, one-third of the shares are forfeited with the remaining two-thirds (i) being retained subject to a three-year cliff vesting schedule as if no termination had occurred or (ii) becoming vested upon a unanimous determination of certain of the remaining members of senior management ("Senior Management"). Upon termination for cause or resignation without good reason, all of the shares are forfeited unless Senior Management determines to allow two-thirds of such shares (x) to be retained

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subject to a three-year cliff vesting schedule as if no termination had occurred or (y) to vest upon a unanimous determination of Senior Management.

(3) Upon his resignation Mr. Black received property with a fair market value of $12,500 and 36,862 shares of Class A Common Stock as severance in exchange for a full release of the company.

Pension Benefits

Other than our 401(k) Plan, we do not have any plan that provides for retirement benefits.

Non-Qualified Deferred Compensation

We do not have any plan that provides for the deferral of compensation on a basis that is not tax qualified.

Director Compensation

We did not award any compensation to our non-employee directors during the fiscal year 2010. For 2011, our board of directors believes that attracting and retaining qualified non-employee directors will be critical to the ongoing operation of our company. Accordingly, we expect that our board of directors will adopt a director compensation plan effective upon consummation of this offering based on the Compensation Consultant's recommendation and report of the companies in our peer group and utilizing the 50^{th} percentile of our peer group as a guideline. We expect this director compensation plan will provide for an annual cash retainer, cash payments for each meeting attended, restricted equity grants, committee chairman retainer payments and reimbursement for certain expenses.

Directors who are also our employees will not receive any additional compensation for their service on our board of directors.

Executive Compensation Risk

We have determined that risks arising from our compensation policies and practices are not reasonably likely to have a material adverse effect on us. We do not believe that our current or proposed compensation policies and practices encourage excessive or unnecessary risk-taking.

Indemnification

Our certificate of incorporation and bylaws provide indemnification rights to the members of our board of directors and permit us to purchase insurance on behalf of any officer, director, employee or other agent for any liability arising out of that person's actions as our officer, director, employee or agent, regardless of whether Delaware law would permit indemnification. After completion of this offering, we will evaluate our existing director and officer liability insurance coverage and make such adjustments we deem appropriate. Additionally, we have entered into separate indemnity agreements with the members of our board of directors and our executive officers to provide additional indemnification benefits, including the right to receive in advance reimbursements for expenses incurred in connection with a defense for which the director is entitled to indemnification. We believe that the limitation of liability provision in our certificate of incorporation and the indemnity agreements will facilitate our ability to continue to attract and retain qualified individuals to serve as directors and officers.

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SECURITIES AUTHORIZED FOR ISSUANCE UNDER EQUITY COMPENSATION PLANS

The following table represents the securities authorized for issuance under our equity compensation plans as of December 31, 2010.

Equity Compensation Plan Information

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans[1]
Equity compensation plans approved by security holders			2,500
Equity compensation plans not approved by security holders			
Total			2,500

(1) Represents the 2,500 shares of our Class B Common Stock available for issuance under the MIP as of December 31, 2010. Following Mr. Black's resignation on May 20, 2011, 4,000 aggregate shares of Class B Common Stock were available for issuance under the MIP of which 600 shares were granted to Mr. Enger on June 30, 2011 in connection with the commencement of his employment.

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CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS

Class B Common Stock Conversion

We are authorized to issue up to 10,000 shares of our Class B Common Stock in the form of shares of restricted stock to employees pursuant to our Management Incentive Plan. On December 23, 2010, Class B Common Stock was awarded in the following amounts: 2,500 shares to Michael R. Starzer, a director and President and Chief Executive Officer; 2,000 shares to Gary A. Grove, a director and Executive Vice President Engineering and Planning and Interim Chief Operating Officer; 1,500 shares to Patrick A. Graham, Executive Vice President Corporate Development; and 1,500 shares to C. Stephen Black (which were subsequently forfeited without vesting upon Mr. Black's resignation). Mr. Enger was granted 600 shares of our Class B Common Stock on June 30, 2011 in connection with the commencement of his employment. The terms of our Class B Common Stock are identical to the terms of our Class A Common Stock except for the conversion right discussed below. The holders of our Class B Common Stock are entitled to one vote per share, and they vote with the holders of our Class A Common Stock as a single group.

If the Value (as defined below) to be received by us in this offering exceeds the Hurdle Rate of Return (as defined below) with respect to a share of our Original Class A Common Stock (as defined below), all outstanding shares of our Class B Common Stock will be converted automatically into shares of Class A Common Stock immediately prior to this offering based on the following conversion formula:

Each share of Class B Common Stock will be multiplied by

- .001% of the product of (1) the number of shares of Original Class A Common Stock and (2) the amount by which the Value of a share of Original Class A Common Stock exceeds the Hurdle Rate of Return as of the closing of this offering; less

- the aggregate of all prior dividends and distributions with respect to a share of Class B Common Stock.

The above product will be divided by the per share fair market value of the Class A Common Stock implied by this offering, as determined by our board of directors in good faith.

The following definitions apply to the conversion of the Class B Common Stock:

"Hurdle Rate of Return" equals $12.52 increased at a 10% annual compounded internal rate of return from December 23, 2010, to the date of this offering; provided, however, that if this offering occurs on or prior to June 24, 2012, the Hurdle Rate of Return shall be computed as though this offering occurred on June 24, 2012.

"Original Class A Common Stock" means only those shares of our Class A Common Stock outstanding immediately after December 23, 2010, regardless whether such shares have been transferred by the initial owner.

"Value," as it relates to Class A Common Stock, means the sum of the following:

- the per share offering price; plus

- the quotient of

  (x) the amount of all dividends or distributions paid on or prior to this offering with respect to Original Class A Common Stock and all other equity securities (including additional shares of Class A Common Stock) held by a person or entity who acquired Original Class A Common Stock on December 23, 2010, or an affiliate of such person or entity, but excluding equity securities issued at fair market value (as determined in good faith by our board of directors) in connection with bona fide equity financing transactions, divided by

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(y)

the number of shares of Original Class A Common Stock; plus

the aggregate amount of all dividends and distributions paid with respect of all shares of Class B Common Stock on or prior to this offering, divided by the number of shares of Original Class A Common Stock.

The Class B Common Stock conversion rights are subject to adjustment to account for certain changes to our common stock outstanding, including stock splits, stock dividends, stock combinations and recapitalization of our common stock. No fractional shares will be issued upon conversion of any Class B Common Stock, and if fractional shares result from such a conversion, the holder of the Class B Common Stock will be entitled to receive from the company cash equal to the market value of such fractional shares, as determined in good faith by our board of directors.

Our Class B Common Stock was issued as shares of restricted stock subject to a time vesting schedule from the grant date of such Class B Common Stock. Prior to vesting, shares of our Class B Common Stock may be forfeited to us for no consideration and may not be sold, transferred or pledged as collateral. The shares of common stock issued upon conversion of the shares of Class B Common Stock immediately prior to this offering will be subject to a three-year vesting schedule commencing upon consummation of this offering.

Following the conversion of the Class B Common Stock and immediately prior to the completion of this offering, our certificate of incorporation will be amended to provide for only one class of common stock. See "*Description of Capital Stock*."

BCEH

BCEH is managed by Michael R. Starzer, our President and Chief Executive Officer, and Gary A. Grove, our Executive Vice President-Engineering and Planning and Interim Chief Operating Officer, and was formed in connection with our Corporate Restructuring to hold 207,083 shares of our Class A Common Stock for subsequent distribution to our employees pursuant to BCEC's Management Incentive Plan. These shares were issued to BCEH in order to defer any tax liability to the recipient resulting from the issuance until a liquid market in our shares of common stock existed.

BCEC Investment Trust

The BCEC Investment Trust, u/t/a, dated April 1, 2011, was formed to hold shares of our common stock received by BCEC in connection with the redemption of BCEC's equity in our Corporate Restructuring and designated for (i) Bonanza Creek Oil Company, LLC; (ii) the co-manager of Bonanza Creek Oil Company, LLC and a former director of BCEC pursuant to his interest in BCEC's Management Incentive Plan; and (iii) employees of BCEC. Mr. Starzer is trustee of this trust. The agreement of both required beneficiaries under the trust, Mr. Starzer and the other co-manager of Bonanza Creek Oil Company, LLC, is required to distribute such shares.

Registration Rights Agreement

We have entered into a registration rights agreement with certain of our stockholders, who we refer to as rights holders, including Black Bear and certain clients of AIMCo, relating to the shares of our common stock held by them and covered by the agreement, which shares of common stock we refer to as registrable shares. Under the registration rights agreement, the rights holders have the right, subject to the terms of the lock-up agreements to be executed in connection with this offering between each such right holder and the underwriters, to require us to register under the Securities Act for offer and sale all or a portion of the registrable shares of such rights holders.

Demand Registration Rights. Black Bear has the right to require us, subject to certain limitations, to register all or a portion of the registrable shares held by Black Bear and clients of AIMCo. AIMCo's clients have the same right with respect to their registrable shares, which may not be exercised until Black Bear either (i) exercises all of its demand rights or (ii) no longer holds registrable shares, whichever occurs first. If Black Bear intends to distribute its registrable shares through an underwritten offering, the clients of AIMCo may elect to have their registrable shares included in the offering, subject to customary underwriters' cutbacks.

The maximum number of registrations Black Bear may require us to effect depends on the gross proceeds of this offering to be received by Black Bear and the clients of AIMCo. If Black Bear and the clients of AIMCo receive less than $175 million in gross proceeds in this offering, Black Bear may require us to file up to two registration statements. If Black Bear and the clients of AIMCo receive $175 million or more in gross proceeds from this offering Black Bear may require us to file only one registration statement. We are not required to file more than one registration statement pursuant to demand by the clients of AIMCo. We are not required to file any registration statement for 180 days after this offering.

If we receive a demand registration request (i) within 30 days prior to a planned registered public offering in which Black Bear and clients of AIMCo may exercise piggyback rights or (ii) while we are engaged in any other activity that, in the good faith determination of our board of directors, would be adversely affected by the requested registration to our material detriment, then we may delay such demand for up to 90 days after such public offering. We may exercise this delay right once in any 12-month period.

Piggyback Registration. Whenever we propose to file a registration statement for our own account or for the account of one of our stockholders, the rights holders have the right to have their registrable shares included in such an offering. Participation in such an offering is subject to customary underwriters' cutbacks and the following priorities:

- in the first demand registration requested by Black Bear: (i) the registrable shares held by Black Bear and clients of AIMCo pro rata based on the number of registrable shares owned by each such holder up to a maximum of $175 million gross proceeds attributable to such holder less any amount of gross proceeds received by such holder in our initial public offering, (ii) registrable shares of other rights holders pro rata based on the number of registriable shares owned by each such rights holder and (iii) other securities to be included in such offering;

- in the second demand registration requested by Black Bear or in the demand registration requested by clients of AIMCo: (i) all of the registrable shares to be offered for all parties to the registration rights agreement pro rata and (ii) any other securities requested to be included in the offering; and

- in any other such registration: (i) all of the securities to be offered for our account, (ii) the regsistrable shares to be offered for all parties to the registration rights agreement pro rata and (iii) any other securities requested to be included in the offering.

Registration Expenses. We are responsible for all expenses arising from or incident to our performance of, or compliance with, the registration rights agreement, regardless of whether any registration statement is declared effective. These expenses include all registration and exchange listing fees, attorneys' fees for us and for counsel selected by holders of a majority of the registrable shares, accounting expenses and liability insurance. We are not responsible for underwriting discounts, selling commissions and the fees of the selling rights holder's own counsel.

Indemnification. The registration rights agreement contains indemnification and contribution provisions, subject to certain conditions, by us for the benefit of the rights holders and their affiliates and representatives and each underwriter, and in limited situations, by the rights holders for the benefit of us and any underwriters with respect to information included in any registration statement, prospectus or related documents.

Transfer. Each rights holder may transfer its rights under the agreement, in whole or part, only to (i) an affiliate of such rights holder or (ii) another person in a private placement exempt from registration under securities laws so long as such person holds at least 1% of the class of registrable shares.

Commercially Reasonable Best Efforts. All registration rights require us to use our commercially reasonable best efforts to obtain registration.

HEC Acquisition

On December 23, 2010, 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 common stock with a value equal to approximately $21 million, for a total purchase price of approximately $80 million, subject to certain adjustments. The members of HEC included current and former members of our management who, collectively, owned an approximate 7.0% equity interest in HEC.

Certain of our directors and executive officers owned equity interests in HEC and received shares of our common stock or cash in exchange for those interests. A trust controlled by Mr. Starzer, our President and Chief Executive Officer owned 1.6% of HEC. Mr. Grove, our Executive Vice President Engineering and Planning and Interim Chief Operating Officer, owned approximately 0.6% of HEC through a family trust. Mr. Graham, our Executive Vice President Corporate Development owned approximately 0.2% of HEC. The trust controlled by Mr. Starzer received 92,067 shares of our common stock, Mr. Grove's family trust received approximately $461,000 in cash consideration and Mr. Graham received approximately $115,000 in cash consideration. Furthermore, following the completion of this acquisition, the controlling unitholder of HEC owned approximately 5.77% of our common stock.

Prior to the acquisition, we provided services to HEC as contractor for their Arkansas and DJ Basin operations. The scope of work included directly performing or managing all the permitting, equipment procurement, logistics, operations supervision and implementation, and documentation for all of HEC's operations. As compensation for our services, HEC reimbursed us for time and materials, and we received a management fee of approximately $34,000 per month.

CJ Bennett Family Trust

On March 25, 2008, BCEC issued a $10 million unsecured subordinated note to the CJ Bennett Family Trust of 1987 (the "Bennett Trust"), the beneficiary of which is a father of one of our former directors. The unsecured subordinated note was repaid in full, including $2.3 million in accrued interest, on December 23, 2010 as part of our Corporate Restructuring.

Procedures for Approval of Related Party Transactions

A "Related Party Transaction" is a transaction, arrangement or relationship in which we or any of our subsidiaries was, is or will be a participant, the amount of which involved exceeds $120,000, and in which any related person had, has or will have a direct or indirect material interest. A "Related Person" means:

- any person who is, or at any time during the applicable period was, one of our executive officers or one of our directors;

- any person who is known by us to be the beneficial owner of more than 5.0% of our common stock;

- any immediate family member of any of the foregoing persons, which means any child, stepchild, parent, stepparent, spouse, sibling, mother-in-law, father-in-law, son-in-law, daughter-in-law, brother-in-law or sister-in-law of a director, executive officer or a beneficial owner of more than 5.0% of our common stock, and any person (other than a tenant or employee) sharing the

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- household of such director, executive officer or beneficial owner of more than 5.0% of our common stock; and

- any firm, corporation or other entity in which any of the foregoing persons is a partner or principal or in a similar position or in which such person has a 10.0% or greater beneficial ownership interest.

Our board of directors will adopt a written related party transactions policy following the completion of this offering. Pursuant to this policy, our audit committee will review all material facts of all Related Party Transactions and either approve or disapprove entry into the Related Party Transaction, subject to certain limited exceptions. In determining whether to approve or disapprove entry into a Related Party Transaction, our audit committee will take into account, among other factors, the following: (1) whether the Related Party Transaction is on terms no less favorable than terms generally available to an unaffiliated third party under the same or similar circumstances and (2) the extent of the Related Person's interest in the transaction.

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PRINCIPAL AND SELLING STOCKHOLDERS

The following table sets forth information with respect to the beneficial ownership of our common stock as of May 31, 2011 as well as on a fully diluted basis immediately after the completion of this offering, by the following persons:

- each stockholder known by us to be the beneficial owner of more than 5% of our outstanding shares of common stock;
- the selling stockholders;
- each of our named executive officers;
- each of our directors; and
- all of our directors and executive officers as a group.

All information with respect to beneficial ownership assumes an offering price of $ per share of common stock (the midpoint of the range set forth on the cover page of this prospectus). Except as otherwise indicated, the persons listed below have sole voting and investment power with respect to all shares of our common stock beneficially owned by them, except to the extent this power may be shared with a spouse. No selling stockholder is a registered broker-dealer or affiliate of a registered broker-dealer.

The address for Project Black Bear LP is 2 Bloor Street East, Suite 810, Toronto, Ontario M4W 1A8 Canada. The address for Her Majesty the Queen in Right of Alberta a client advised by AIMCo is c/o AIMCo, 1100-10830 Jasper Avenue, Edmonton, Alberta T5J 2B3. The address for D. E. Shaw Synoptic Portfolios 5, L.L.C. is 1166 Avenue of the Americas, Fifth Floor, New York, New York, 10036. The address for the Fred S. and Barbara J. Holmes Trust dated January 10, 1983 is P.O. Box 1405, Taft, California 93268. The address for our directors and executive officers is 410 17th Street, Suite 1500, Denver, Colorado, 80202.

	Shares Beneficially Owned Prior to the Offering			Shares Being Offered	Shares Beneficially Owned After the Offering	
Name of Beneficial Owner	**Class A Common Stock**	**Class B Common Stock[1]**	**Percentage**	**Common Stock**	**Common Stock**	**Percentage**
Selling Stockholders						
Project Black Bear LP[2]	21,166,134		72.66%			
Her Majesty the Queen in Right of Alberta[3]	7,587,859		26.05%			
Other Significant Stockholders						
West Face Capital Inc.[2]	21,166,134		72.66%			
Alberta Investment Management Corporation[3]	7,587,859		26.05%			
D. E. Shaw Synoptic Portfolios 5, L.L.C.[4].	3,763,908		12.92%			
BCEC Investment Trust[5]	1,811,903		6.22%			
The Fred S. and Barbara J. Holmes Trust	1,591,469		5.46%			
Directors and Executive Officers						
Michael R. Starzer[6]	2,428,195	2,500(9)	8.34%			
Gary A. Grove[7]	343,036	2,000(9)	1.18%			
Patrick A. Graham		1,500(9)	*			
Steven R. Enger		600(9)	*			
Richard J. Carty						
Todd A. Overbergen[8]						
James R. Casperson						
Marvin Chronister						

Kevin A. Neveu	
All directors and executive officers as a group (9 persons)	

* Less than 1.0%.

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(1)

6,600 shares of Class B Common Stock in the form of restricted stock have been issued to certain of our named executive officers, and we intend to issue the remaining shares of Class B Common Stock prior to this offering. Immediately prior to the consummation of this offering, each share of Class B Common Stock will be converted into Class A Common Stock pursuant to the terms of our amended and restated certificate of incorporation. See "*Certain Relationships and Related Party Transactions Class B Common Stock Conversion*." Our amended and restated certificate of incorporation will be amended and restated effective immediately prior to the consummation of this offering and after the conversion of the Class B Common Stock into Class A Common Stock, at which time each share of Class A Common Stock then outstanding will be exchanged for one share of our single-class common stock. Shares of our common stock previously held as Class B Common Stock will remain restricted stock and will be subject to three-year time vesting commencing from the consummation of this offering.

(2)

Includes beneficial ownership of 7,587,859 shares of common stock held by certain clients of AIMCo, over which Black Bear may exercise voting power pursuant to an investment management agreement between West Face Capital and AIMCo, on behalf of its clients. This investment management agreement may be terminated upon 90 days prior written notice or immediately in certain circumstances, at which time West Face Capital would no longer be deemed a beneficial owner of the common stock held by certain clients of AIMCo. The general partner of Black Bear, Project Black Bear GP LLC, a Delaware limited liability company, has delegated voting and investment power over the shares held by Black Bear to West Face Capital, pursuant to an advisory agreement. Voting and investment decisions of West Face Capital are made by its Co-Chief Investment Officers, Gregory Boland and Peter Fraser, each of whom disclaims beneficial ownership of any shares held by Black Bear and Her Majesty the Queen in Right of the Province of Alberta.

(3)

Her Majesty the Queen in Right of the Province of Alberta is a client of AIMCo. Her Majesty the Queen in Right of the Province of Alberta holds shares of our common stock in her own capacity and as trustee/nominee for certain other Alberta pension clients for which AIMCo serves as investment manager pursuant to the Alberta Investment Management Corporation Act R.S.A. C.A. 26-5 (2007). Black Bear may exercise voting power over all these shares pursuant to an investment management agreement between West Face Capital and AIMCo, on behalf of its clients. Voting and investment decisions of the clients of AIMCo with respect to the shares of our common stock owned by such clients are made by AIMCo's Senior Vice President Public Equities, Brian Gibson, and AIMCo's Vice President Relationship Investments, David Styles, each of whom disclaims beneficial ownership of any shares of our common stock held by the clients of AIMCo.

(4)

D. E. Shaw & Co., L.P., as investment adviser, has voting and investment control over the shares beneficially owned by D.E. Shaw Synoptic Portfolios 5, L.L.C. Voting and investment control over the shares of D.E. Shaw & Co., L.P. are exercised by Julius Gaudio, Eric Wepsic, Maximilian Stone, Anne Dinning and Lou Salkind, or their designees, each of whom disclaim beneficial ownership of the shares held by D. E. Shaw Synoptic Portfolios 5, L.L.C.

(5)

Mr. Starzer is sole trustee of the BCEC Investment Trust and, as such, has voting power over these shares, but dispositive power requires the joint consent of Mr. Starzer and the other beneficiary of the trust.

(6)

Includes (i) 1,811,903 shares over which Mr. Starzer has voting power as sole trustee of the BCEC Investment Trust; (ii) 317,142 shares held directly; (iii) 207,083 shares held by BCEH, over which Messrs. Starzer and Grove exercise joint voting and dispositive control; and (iv) 92,067 shares held by The Starzer Revocable Living Trust.

(7)

Includes (i) 135,953 shares held directly and (ii) 207,083 shares held by BCEH, over which Messrs. Starzer and Grove exercise joint voting and dispositive control.

(8)

Does not include shares held by D.E. Shaw Synoptic Portfolios 5, L.L.C., an affiliate of the D.E. Shaw Group. Mr. Overbergen is a director in the D.E. Shaw Group, and although he may be deemed to share beneficial ownership of the shares held by D.E. Shaw Synoptic Portfolios 5, L.L.C. by virtue of his relationship with the D.E. Shaw Group, he disclaims beneficial ownership of the shares held by D.E. Shaw Synoptic Portfolios 5, L.L.C.

(9)

Shares of our common stock previously held as Class B Common Stock will remain restricted stock and will be subject to three-year time vesting commencing from the consummation of this offering.

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DESCRIPTION OF CAPITAL STOCK

General

We expect to amend and restate our certificate of incorporation and bylaws immediately prior to the consummation of this offering. The following descriptions are summaries of the material terms that we expect to include in our amended and restated certificate of incorporation and bylaws. This summary is qualified by reference to our amended and restated certificate of incorporation and amended and restated bylaws, the form of which are filed as exhibits to the registration statement of which this prospectus forms a part, and by the provisions of applicable law.

We are authorized to issue shares of common stock, par value $0.001 per share, and shares of preferred stock, par value $0.001 per share. Upon completion of the offering, there will be shares of our sole class of common stock issued and outstanding and no shares of our preferred stock outstanding.

We intend to apply to list shares of our common stock on the NYSE under the symbol "BCEI."

Common Stock

Voting

We expect that holders of shares of our common stock will be entitled to one vote for each share held of record on each matter submitted to a vote of stockholders, including the election of directors, and will not have any cumulative voting rights with regard to the election of directors.

Dividends

We expect that holders of shares of our common stock will be entitled to receive ratably such dividends as our board of directors from time to time may declare out of funds legally available therefor.

Liquidation Rights

In the event of any liquidation, dissolution or winding-up of our affairs, we expect that, after payment of all of our debts and liabilities, the holders of common stock will be entitled to share ratably in the distribution of any of our remaining assets.

Other Matters

Except as described below, we do not expect that holders of shares of our common stock will have any conversion, preemptive or other subscription rights and that there will be no redemption rights or sinking fund provisions with respect to the common stock.

Our Preferred Stock

We expect that our board of directors will have the authority to issue preferred stock in one or more classes or series and to fix the designations, powers, preferences and rights, and the qualifications, limitations or restrictions thereof, including dividend rights, dividend rates, conversion rights, voting rights, terms of redemption, redemption prices, liquidation preferences and the number of shares constituting any class or series, without further vote or action by the stockholders. The issuance of preferred stock may have the effect of delaying, deferring or preventing a change in control of us without further action by the stockholders and may adversely affect the voting and other rights of the holders of common stock.

Transfer Agent

Our transfer agent and registrar will be .

Anti-Takeover Effects of Delaware Laws and Our Charter and Bylaws Provisions

We expect that our certificate of incorporation and bylaws will include anti-takeover provisions that may delay, deter, or prevent a tender offer or takeover attempt that a stockholder might consider to be in its best interests, including attempts that might result in a premium being paid over the market price for the shares held by stockholders.

Such provisions, if included in our certificate of incorporation and bylaws, could discourage potential acquisition proposals and could delay or prevent a change of control. Such provisions would be intended to enhance the likelihood of continuity and stability in the composition of the board of directors and in the policies formulated by the board of directors and to discourage certain types of transactions that may involve an actual or threatened change of control. Such provisions would be designed to reduce our vulnerability to an unsolicited acquisition proposal. Such provisions also would be intended to discourage certain tactics that may be used in proxy fights. However, such provisions could have the effect of discouraging others from making tender offers for our shares and, as a consequence, they also may inhibit fluctuations in the market price of our common stock that could result from actual or rumored takeover attempts. Such provisions also may have the effect of preventing changes in our management.

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

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

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

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

- the business combination is approved by our board of directors on or subsequent to the date the person became an interested stockholder and authorized at an annual or special meeting of the stockholders by the affirmative vote of the holders of at least 66 2/3% of the outstanding voting stock that is not owned by the interested stockholder.

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

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SHARES ELIGIBLE FOR FUTURE SALE

Prior to this offering, there has been no public market for our common stock. Future sales of our common stock in the public market, or the availability of such shares for sale in the public market, could adversely affect market prices prevailing from time to time. As described below, only a limited number of shares will be available for sale shortly after this offering due to contractual and legal restrictions on resale. Nevertheless, sales of a substantial number of shares of our common stock in the public market after such restrictions lapse, or the perception that those sales may occur, could adversely affect the prevailing market price at such time and our ability to raise equity-related capital at a time and price we deem appropriate.

Sales of Restricted Shares

Upon the closing of this offering, we will have outstanding an aggregate of shares of common stock. All of the shares of common stock to be sold in this offering will be freely tradable without restriction or further registration under the Securities Act, unless the shares are held by any of our "affiliates" as such term is defined in Rule 144 of the Securities Act. All remaining shares of common stock held by existing stockholders will be deemed "restricted securities" as such term is defined under Rule 144. The restricted securities were issued and sold by us in private transactions and are eligible for public sale only if registered under the Securities Act or if they qualify for an exemption from registration under Rule 144 or Rule 701 under the Securities Act, which rules are summarized below.

As a result of the lock-up agreements described below and the provisions of Rule 144 and Rule 701 under the Securities Act, all of the shares of our common stock (excluding the shares to be sold in this offering) will be available for sale in the public market upon the expiration of the lock-up agreements, beginning 180 days after the date of this prospectus (subject to extension) and when permitted under Rule 144 or Rule 701.

Lock-up Agreements

We, all of our directors and officers, certain of our principal stockholders and the selling stockholders have agreed not to sell or otherwise transfer or dispose of any common stock for a period of 180 days from the date of this prospectus, subject to certain exceptions and extensions. See "*Underwriters*" for a description of these lock-up provisions.

Rule 144

In general, under Rule 144 as currently in effect, once we have been a reporting company subject to the reporting requirements of Section 13 or 15(d) of the Exchange Act for 90 days, a person (or persons whose shares are aggregated) who is not deemed to have been an affiliate of ours at any time during the three months preceding a sale, and who has beneficially owned restricted securities within the meaning of Rule 144 for at least six months (including any period of consecutive ownership of preceding non-affiliated holders) would be entitled to sell those shares, subject only to the availability of current public information about us. A non-affiliated person who has beneficially owned restricted securities within the meaning of Rule 144 for at least one year would be entitled to sell those shares without regard to the provisions of Rule 144.

Once we have been a reporting company subject to the reporting requirements of Section 13 or 15(d) of the Exchange Act for 90 days, a person (or persons whose shares are aggregated) who is deemed to be an affiliate of ours and who has beneficially owned restricted securities within the meaning of Rule 144 for at least six months would be entitled to sell within any three-month period a number of shares that does not exceed the greater of one percent of the then outstanding shares of our common stock or the average weekly trading volume of our common stock reported through the NYSE during the four calendar weeks preceding the filing of notice of the sale. Such sales are also subject to certain manner of sale provisions, notice requirements and the availability of current public information about us.

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Rule 701

Employees, directors, officers, consultants or advisors who purchases shares from us in connection with a compensatory stock or option plan or other written compensatory agreement in accordance with Rule 701 before the effective date of the registration statement are entitled to sell such shares 90 days after the effective date of the registration statement in reliance on Rule 144 without having to comply with the holding period requirement of Rule 144 and, in the case of non-affiliates, without having to comply with the public information, volume limitation or notice filing provisions of Rule 144. The SEC has indicated that Rule 701 will apply to typical stock options granted by an issuer before it becomes subject to the reporting requirements of the Exchange Act, along with the shares acquired upon exercise of such options, including exercises after the date of this prospectus.

Stock Issue Under Employee Plans

We intend to file a registration statement on Form S-8 under the Securities Act to register stock issuable under our new Long-Term Incentive Plan upon its adoption. This registration statement is expected to be filed following the effective date of the registration statement of which this prospectus is a part and will be effective upon filing. Accordingly, shares registered under such registration statement will be available for sale in the open market following the effective date, unless such shares are subject to vesting restrictions with us, Rule 144 restrictions applicable to our affiliates or the lock-up restrictions described above.

Registration Rights

We have entered into a registration rights agreement with the certain of our stockholders, which will require us to file and effect the registration of certain shares of our common stock held by such parties in certain circumstances. See "*Certain Relationships and Related Party Transactions Registration Rights Agreement*."

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MATERIAL U.S. FEDERAL INCOME TAX CONSIDERATIONS TO NON-U.S. HOLDERS

The following is a general discussion of the material U.S. federal income tax consequences of the acquisition, ownership and disposition of our common stock to a non-U.S. holder. For the purpose of this discussion, a non-U.S. holder is any beneficial owner of our common stock that is not for U.S. federal income tax purposes any of the following:

- an individual citizen or resident of the U.S.;
- a corporation (or other entity treated as a corporation for U.S. federal income tax purposes) created or organized in the U.S. or under the laws of the U.S. or any state or the District of Columbia;
- a partnership (or other entity treated as a partnership or other pass-through entity for U.S. federal income tax purposes);
- an estate whose income is subject to U.S. federal income tax regardless of its source; or
- a trust (x) whose administration is subject to the primary supervision of a U.S. court and which has one or more U.S. persons who have the authority to control all substantial decisions of the trust or (y) which has made a valid election to be treated as a U.S. person.

If a partnership (or an entity treated as a partnership for U.S. federal income tax purposes) holds our common stock, the tax treatment of a partner in the partnership will generally depend on the status of the partner and upon the activities of the partnership. Accordingly, we urge partnerships that hold our common stock and partners in such partnerships to consult their tax advisors.

This discussion assumes that a non-U.S. holder will hold our common stock issued pursuant to the offering as a capital asset (generally, property held for investment). This discussion does not address all aspects of U.S. federal income taxation or any aspects of estate, gift, alternative minimum tax, state, local or non-U.S. taxation, nor does it consider any U.S. federal income tax considerations that may be relevant to non-U.S. holders that may be subject to special treatment under U.S. federal income tax laws, including, without limitation, U.S. expatriates, life insurance companies, tax-exempt or governmental organizations, dealers in securities or currency, banks or other financial institutions, investors whose functional currency is other than the U.S. dollar, registered investment companies, real estate investment trusts, "controlled foreign corporations," passive foreign investment companies, persons who own, directly or indirectly, more than 5% of our common stock and investors that hold our common stock as part of a hedge, straddle or conversion transaction. Furthermore, the following discussion is based on current provisions of the Internal Revenue Code of 1986, as amended, and Treasury Regulations and administrative and judicial interpretations thereof, all as in effect on the date hereof, and all of which are subject to change, possibly with retroactive effect.

We urge each prospective investor to consult a tax advisor regarding the U.S. federal, state, local and non-U.S. income and other tax consequences of acquiring, holding and disposing of shares of our common stock.

Dividends

We have not paid any dividends on our common stock, and we do not plan to pay any dividends for the foreseeable future. However, if we do pay dividends on our common stock, those payments will constitute dividends for U.S. tax purposes to the extent paid from our current or accumulated earnings and profits, as determined under U.S. federal income tax principles. To the extent those dividends exceed our current and accumulated earnings and profits, the dividends will constitute a return of capital and will first reduce a holder's adjusted tax basis in the common stock, but not below zero, and then will be treated as gain from the sale of the common stock; see " *Gain on Disposition of Common Stock*".

Any dividend (out of earnings and profits) paid to a non-U.S. holder of our common stock generally will be subject to U.S. withholding tax either at a rate of 30% of the gross amount of the dividend or such lower rate as may be specified by an applicable tax treaty. To receive the benefit of a reduced treaty rate, a non-U.S. holder must provide us with an Internal Revenue Service ("IRS") Form W-8BEN or other appropriate version of IRS Form W-8 certifying qualification for the reduced rate.

Dividends received by a non-U.S. holder that are effectively connected with a U.S. trade or business conducted by the non-U.S. holder (and, if required by an applicable tax treaty, attributable to a permanent establishment or fixed tax base maintained by the non-U.S. holder in the United States) are exempt from such withholding tax. To obtain this exemption, the non-U.S. holder must provide us with an IRS Form W-8ECI properly certifying such exemption. Such effectively connected dividends, although not subject to withholding tax, will be subject to U.S. federal income tax on a net income basis at the same graduated rates generally applicable to U.S. persons, net of certain deductions and credits, subject to any applicable tax treaty providing otherwise. In addition to the income tax described above, dividends received by corporate non-U.S. holders that are effectively connected with a U.S. trade or business of the corporate non-U.S. holder may be subject to a branch profits tax at a rate of 30% or such lower rate as may be specified by an applicable tax treaty.

A non-U.S. holder of our common stock may obtain a refund of any excess amounts withheld if the non-U.S. holder is eligible for a reduced rate of United States withholding tax and an appropriate claim for refund is timely filed with the Internal Revenue Service or the IRS.

Gain on Disposition of Common Stock

A non-U.S. holder generally will not be subject to U.S. federal income tax on any gain realized upon the sale or other disposition of our common stock unless:

- the gain is effectively connected with a U.S. trade or business of the non-U.S. holder and, if required by an applicable tax treaty, is attributable to a permanent establishment or fixed base maintained by such non-U.S. holder in the United States;
- the non-U.S. holder is an individual who is present in the United States for a period or periods aggregating 183 days or more during the calendar year in which the sale or disposition occurs and certain other conditions are met; or
- we are or have been a "U.S. real property holding corporation" for U.S. federal income tax purposes during specified periods.

Unless an applicable tax treaty provides otherwise, gain described in the first bullet point above will be subject to U.S. federal income tax on net income basis at the same graduated rates generally applicable to U.S. persons. Corporate non-U.S. holders also may be subject to a branch profits tax equal to 30% (or such lower rate as may be specified by an applicable tax treaty) of its earnings and profits that are effectively connected with a U.S. trade or business.

Gain described in the second bullet point above (which may be offset by U.S. source capital losses, provided that the non-U.S. holder has timely filed U.S. federal income tax returns with respect to such losses) will be subject to a flat 30% U.S. federal income tax (or such lower rate as may be specified by an applicable tax treaty).

Non-U.S. holders should consult any applicable income tax treaties that may provide for different rules.

We believe that we currently are, and expect to remain for the foreseeable future, a "U.S. real property holding corporation." However, so long as our common stock is "regularly traded on an established securities market," a non-U.S. holder will be subject to U.S. federal net income tax on a disposition of our common stock only if the non-U.S. holder actually or constructively holds, or held at any time during the shorter of the five-year period preceding the date of disposition or the holder's holding period, more than 5% of our common stock. If our common stock is not considered to be so traded, all non-U.S. holders would be subject to U.S. federal net income tax on disposition of our common stock, and a 10% withholding would apply to the gross proceeds from the sale of our common stock by a non-U.S. holder.

Backup Withholding and Information Reporting

Generally, we must report annually to the IRS the amount of dividends paid to each non-U.S. holder, the name and address of the recipient, and the amount, if any, of tax withheld with respect to those dividends. A similar report is sent to each non-U.S. holder. These information reporting requirements apply even if withholding was not required. Pursuant to tax treaties or other agreements, the IRS may make its reports available to tax authorities in the recipient's country of residence.

Payments of dividends to a non-U.S. holder may be subject to backup withholding (at the applicable rate) unless the non-U.S. holder establishes an exemption, for example, by properly certifying its non-U.S. status on an IRS Form W-8BEN or another appropriate version of IRS Form W-8. Notwithstanding the foregoing, backup withholding may apply if either we or our paying agent has actual knowledge, or reason to know, that the beneficial owner is a U.S. person that is not an exempt recipient.

Payments of the proceeds from sale or other disposition by a non-U.S. holder of our common stock effected outside the U.S. by or through a foreign office of a broker generally will not be subject to information reporting or backup withholding. However, information reporting (but not backup withholding) will apply to those payments if the broker does not have documentary evidence that the holder is a non-U.S. holder, an exemption is not otherwise established, and the broker has certain relationships with the United States.

Payments of the proceeds from a sale or other disposition by a non-U.S. holder of our common stock effected by or through a U.S. office of a broker generally will be subject to information reporting and backup withholding (at the applicable rate) unless the non-U.S. holder establishes an exemption, for example, by properly certifying its non-U.S. status on an IRS Form W-8BEN or another appropriate version of IRS Form W-8. Notwithstanding the foregoing, information reporting and backup withholding may apply if the broker has actual knowledge, or reason to know, that the holder is a U.S. person that is not an exempt recipient.

Backup withholding is not an additional tax. Rather, the U.S. income tax liability of persons subject to backup withholding will be reduced by the amount of tax withheld. If withholding results in an overpayment of taxes, a refund may be obtained, provided that the required information is timely furnished to the IRS.

Legislation Affecting Common Stock Held Through Foreign Accounts

On March 18, 2010, President Obama signed into law the Hiring Incentives to Restore Employment Act (the "HIRE Act"), which may result in materially different withholding and information reporting requirements than those described above, for payments made after December 31, 2012. The HIRE Act limits the ability of non-U.S. holders who hold our common stock through a foreign financial institution to claim relief from U.S. withholding tax in respect of dividends paid on our common stock unless the foreign financial institution agrees, among other things, to annually report certain information with respect to "United States accounts" maintained by such institution. The HIRE Act also limits the ability of certain non-financial foreign entities to claim relief from U.S. withholding tax in respect of dividends paid by us to such entities unless (1) those entities meet certain certification requirements; (2) the withholding agent does not know or have reason to know that any such information provided is incorrect and (3) the withholding agent reports the information provided to the IRS. The HIRE Act provisions will have a similar effect with respect to dispositions of our common stock after December 31, 2012. A non-U.S. holder generally would be permitted to claim a refund to the extent any tax withheld exceeded the holder's actual tax liability. Non-U.S. holders are encouraged to consult with their tax advisers regarding the possible implication of the HIRE Act on their investment in respect of the common stock.

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UNDERWRITERS

Under the terms and subject to the conditions contained in an underwriting agreement dated the date of this prospectus, the underwriters named below, for whom Morgan Stanley & Co. LLC is acting as the representative, have severally agreed to purchase, and we and the selling stockholders have agreed to sell to them, severally, the number of shares indicated below:

Name	Number of Shares
Morgan Stanley & Co. LLC	

The underwriters and the representatives are collectively referred to as the "underwriters" and the "representatives," respectively. The underwriters are offering the shares of common stock subject to their acceptance of the shares from us and the selling stockholders and subject to prior sale. The underwriting agreement provides that the obligations of the several underwriters to pay for and accept delivery of the shares of common stock offered by this prospectus are subject to the approval of certain legal matters by their counsel and to certain other conditions. The underwriters are obligated to take and pay for all of the shares of common stock offered by this prospectus if any such shares are taken. However, the underwriters are not required to take or pay for the shares covered by the underwriters' over-allotment option described below.

The per share price of any shares sold by the underwriters shall be the public offering price listed on the cover page of this prospectus, in United States dollars, less an amount not greater than the per share amount of the concession to dealers described below.

The underwriters initially propose to offer part of the shares of common stock directly to the public at the public offering price listed on the cover page of this prospectus and part to certain dealers at a price that represents a concession not in excess of $ a share under the public offering price. Any underwriter may allow, and such dealers may reallow, a concession not in excess of $ a share to other underwriters or to certain dealers. After the initial offering of the shares of common stock, the offering price and other selling terms may from time to time be varied by the representatives.

The selling stockholders have granted to the underwriters an option, exercisable for 30 days from the date of this prospectus, to purchase up to an aggregate of additional shares of common stock at the public offering price listed on the cover page of this prospectus, less underwriting discounts and commissions. The underwriters may exercise this option solely for the purpose of covering over-allotments, if any, made in connection with the offering of the shares of common stock offered by this prospectus. To the extent the option is exercised, each underwriter will become obligated, subject to certain conditions, to purchase about the same percentage of the additional shares of common stock as the number listed next to the underwriter's name in the preceding table bears to the total number of shares of common stock listed next to the names of all underwriters in the preceding table. If the underwriters' option is exercised in full, the total price to the public would be approximately $, the total underwriters' discounts and commissions would be approximately $ million, and the total proceeds to the selling stockholders would be approximately $ million.

The underwriters have informed us that they do not intend sales to discretionary accounts to exceed five percent of the total number of shares of common stock offered by them.

We intend to apply to list shares of our common stock on the NYSE under the symbol "BCEI."

We, all of our directors and officers, certain of our principal stockholders and the selling stockholders have agreed that, without the prior written consent of Morgan Stanley & Co. LLC and subject to certain exceptions, on behalf of the underwriters, we and they will not, during the period ending 180 days after the date of this prospectus:

- offer, pledge, sell, contract to sell, sell any option or contract to purchase, purchase any option or contract to sell, grant any option, right or warrant to purchase, lend or otherwise transfer or dispose of directly or indirectly, any shares of common stock or any securities convertible into or exercisable for common stock; or

- enter into any swap or other arrangement that transfers to another, in whole or in part, any of the economic consequences of ownership of the common stock.

whether any transaction described above is to be settled by delivery of common stock or such other securities, in cash or otherwise. Notwithstanding the foregoing, if (1) during the last 17 days of the 180-day restricted period, we issue an earnings release or material news or a material event relating to our company occurs; or (2) prior to the expiration of the 180-day restricted period, we announce that we will release earnings results during the 16-day period beginning on the last day of the 180-day period, the restrictions described above shall continue to apply until the expiration of the 18-day period beginning on the issuance of the earnings release or the occurrence of the material news or material event.

The restrictions described in the immediately preceding paragraph shall not apply to:

- the sale of shares to the underwriters;

- the issuance by us of shares of common stock upon the exercise of an option or a warrant or the conversion of a security outstanding on the date of this prospectus of which the underwriters have been advised in writing; or

- transactions by any person other than us relating to shares of common stock or other securities acquired in open market transactions after completion of the offering of the shares.

In order to facilitate the offering of the common stock, the underwriters may engage in transactions that stabilize, maintain or otherwise affect the price of the common stock. Specifically, the underwriters may over-allot in connection with the offering, creating a short position in the common stock for their own account. In addition, to cover over-allotments or to stabilize the price of the common stock, the underwriters may bid for, and purchase, shares of common stock in the open market. Finally, the underwriting syndicate may reclaim selling concessions allowed to an underwriter or a dealer for distributing the common stock in the offering, if the syndicate repurchases previously distributed common stock in transactions to cover syndicate short positions, in stabilization transactions or otherwise. Any of these activities may stabilize or maintain the market price of the common stock above independent market levels. The underwriters are not required to engage in these activities, and may end any of these activities at any time.

We, the selling stockholders and the underwriters have agreed to indemnify each other against certain liabilities, including liabilities under the Securities Act.

Pricing of the Offering

Prior to this offering, there has been no public market for our common stock. The initial public offering price is determined by negotiations between us, the selling stockholders and the representatives. Among the factors to be considered in determining the initial public offering price will be the information set forth in this prospectus, our history and future prospects, the history of and future prospects for our industry in general, our sales, earnings and certain other financial and operating information in recent

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periods, and the price-earnings ratios, price-sales ratios, market prices of securities and certain financial and operating information of companies engaged in activities similar to ours. The estimated initial public offering price range set forth on the cover page of this preliminary prospectus is subject to change as a result of market conditions and other factors.

Relationships with Underwriters

From time to time in the ordinary course of business, certain of the underwriters and their respective affiliates have performed, and may in the future perform, various commercial banking, investment banking and other financial services for us for which they received, or will receive, customary fees and reimbursement of expenses.

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LEGAL MATTERS

The validity of our common stock offered by this prospectus will be passed upon for Bonanza Creek Energy, Inc., by Mayer Brown LLP, Houston, Texas. Certain legal matters in connection with this offering will be passed upon for the underwriters by Latham & Watkins LLP, Houston, Texas.

EXPERTS

Our consolidated financial statements as of December 31, 2010 and for the period from inception (December 23, 2010) to December 31, 2010 included in this prospectus has been so included in reliance on the report of Hein & Associates LLP, an independent registered public accounting firm, given on the authority of said firm as experts in auditing and accounting.

The consolidated financial statements of BCEC as of December 23, 2010 and December 31, 2009 and for the period January 1, 2010 to December 23, 2010 and for the years ended December 31, 2009 and 2008 included in this prospectus have been so included in reliance on the report of Hein & Associates LLP, an independent registered public accounting firm, given on the authority of said firm as experts in auditing and accounting.

The financial statements of HEC as of December 23, 2010 and December 31, 2009 and for the period January 1, 2010 to December 23, 2010 and for the period from Inception (May 1, 2009) to December 31, 2009 included in this prospectus have been so included in reliance on the report of Hein & Associates LLP, an independent registered public accounting firm, given on the authority of said firm as experts in auditing and accounting.

WHERE YOU CAN FIND MORE INFORMATION

We have filed with the SEC a registration statement on Form S-1 (including the exhibits, schedules and amendments thereto) under the Securities Act, with respect to the shares of our common stock offered hereby. This prospectus does not contain all of the information set forth in the registration statement and the exhibits and schedules thereto. For further information with respect to us and the common stock offered hereby, we refer you to the registration statement and the exhibits and schedules filed therewith. Statements contained in this prospectus as to the contents of any contract, agreement or any other document are summaries of the material terms of this contract, agreement or other document. With respect to each of these contracts, agreements or other documents filed as an exhibit to the registration statement, reference is made to the exhibits for a more complete description of the matter involved. A copy of the registration statement, and the exhibits and schedules thereto, may be inspected without charge at the public reference facilities maintained by the SEC at 100 F Street NE, Washington, D.C. 20549. Copies of these materials may be obtained, upon payment of a duplicating fee, from the Public Reference Section of the SEC at 100 F Street NE, Washington, D.C. 20549. Please call the SEC at 1-800-SEC-0330 for further information on the operation of the public reference facility. The SEC maintains a website that contains reports, proxy and information statements and other information regarding registrants that file electronically with the SEC. The address of the SEC's website is http://*www.sec.gov*.

After we have completed this offering, we will file annual, quarterly and current reports, proxy statements and other information with the SEC. We expect to have an operational website concurrently with the completion of this offering and we expect to make our periodic reports and other information filed with or furnished to the SEC available, free of charge, through our website, as soon as reasonably practicable after those reports and other information are electronically filed with or furnished to the SEC. Information on our website or any other website is not incorporated by reference into this prospectus and does not constitute a part of this prospectus. You may read and copy any reports, statements or other information on file at the public reference rooms. You can also request copies of these documents, for a copying fee, by writing to the SEC, or you can review these documents on the SEC's website, as described above. In addition, we will provide electronic or paper copies of our filings free of charge upon request.

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GLOSSARY OF CERTAIN INDUSTRY TERMS

The definitions set forth below shall apply to the indicated terms as used in this prospectus. All natural gas reserves and production reported in this prospectus are stated at the legal pressure base of the state or area where the reserves exist and at 60 degrees Fahrenheit.

"*3-D seismic data*" Geophysical data that depicts the subsurface strata in three dimensions.

"*API gravity*" or "*American Petroleum Institute gravity*" API gravity is a measure of how heavy or light a petroleum liquid is compared to water. If its API gravity is greater than 10°, it is lighter and floats on water; if less than 10°, it is heavier and sinks. API gravity is thus an inverse measure of the relative density of a petroleum liquid and the density of water, but it is used to compare the relative densities of petroleum liquids. Generally speaking, oil with an API gravity between 40° and 45° commands the highest prices. Above 45° degrees the molecular chains become shorter and less valuable to refineries. Crude oil is classified as light, medium or heavy, according to its measured API gravity:

(a) Light crude oil is defined as having an API gravity higher than 31.1°API.

(b) Medium oil is defined as having an API gravity between 22.3°API and 31.1°API.

(c) Heavy oil is defined as having an API gravity below 22.3°API.

(d) Extra heavy oil is defined with API gravity below 10.0°API.

"*Analogous reservoir*" Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

(i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);

(ii) Same environment of deposition;

(iii) Similar geological structure; and

(iv) Same drive mechanism.

"*Basin*" A large natural depression on the earth's surface in which sediments generally brought by water accumulate.

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

"*Boe*" One barrel of oil equivalent. Determined using a ratio of one barrel of crude oil to six Mcf of natural gas.

"*Btu*" British thermal unit, which is the heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

"*Completion*" The process of strengthening a well hole with casing, evaluating the pressure and temperature of the formation, and then installing the proper equipment to ensure an efficient flow of oil and natural gas out of the well.

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

"*Developed oil and gas reserves*" Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

"*Development costs*" Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.

(ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.

(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.

(iv) Provide improved recovery systems.

"*Development project*" A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

"*Development well*" A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

"*EBITDAX*" See "*Summary Reserve and Operations Data Non-GAAP Financial Measures and Reconciliation Adjusted EBITDAX*."

"*Economically producible*" The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities.

"*Environmental assessment*" A study that can be required pursuant to federal law to assess the potential direct, indirect and cumulative impacts of a project.

"*Exploratory well*" A well drilled to find and produce natural gas or oil reserves not classified as proved, to find a new reservoir in a field previously found to be productive of natural gas or oil in another reservoir or to extend a known reservoir.

"*Field*" An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious, strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms structural feature and

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stratigraphic condition are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

"*Formation*" A layer of rock which has distinct characteristics that differ from nearby rock.

"*Fracture stimulation*" A process whereby fluids mixed with proppants are injected into a well bore under pressure in order to fracture, or crack open, reservoir rock, thereby allowing oil and/or natural gas trapped in the reservoir rock to travel through the fractures and into the well for production.

"*Gross well or acre*" A well or acre in which the registrant owns a working interest. The number of gross wells is the total number of wells in which the registrant owns a working interest.

"*Horizon*" A reservoir bed within the stratigraphic series of an oil province from which gas or liquid hydrocarbons can be obtained by drilling a well.

"*Horizontal drilling*" A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a right angle within a specified interval.

"*Infill drilling*" Drilling wells in between established producing wells to increase recovery of oil and natural gas from a known reservoir.

"*MBbls*" One thousand barrels of crude oil or other liquid hydrocarbons.

"*MBoe*" One thousand barrels of oil equivalent. Determined using the ratio of one barrel of crude oil to six Mcf of natural gas.

"*Mcf*" One thousand cubic feet of natural gas.

"*Millidarcy*" or "*millidarcies*" A unit of measure of permeability. A millidarcy is 1/1000 of a darcy; one darcy reflects permeability such that a pressure differential of 1 atmosphere across 1 cubic centimeter of rock will force a liquid of 1 centipoise of viscosity through the rock at a rate of 1 cubic centimeter per second.

"*MMBbls*" One million barrels of crude oil or other liquid hydrocarbons.

"*MMBoe*" One million barrels of oil equivalent. Determined using the ratio of one barrel of crude oil to six Mcf of natural gas.

"*MMBtu*" One million British thermal units (Btu).

"*MMcf*" One million cubic feet of natural gas.

"*Net revenue interest*" Economic interest remaining after deducting all royalty interests, overriding royalty interests and other burdens from the working interest ownership.

"*Net well or acre*" Deemed to exist when the sum of fractional ownership working interests in gross wells or acres equals one. The number of net wells or acres is the sum of the fractional working interests owned in gross wells or acres expressed as whole numbers and fractions of whole numbers.

"*NYMEX*" The New York Mercantile Exchange.

"*Original oil in place*" Refers to the oil in place before the commencement of production. Oil in place is distinct from oil reserves, which are the technically and economically recoverable portion of oil volume in the reservoir.

"*Play*" A term applied to a portion of the exploration and production cycle following the identification by geologists and geophysicists of areas with potential oil and gas reserves.

"*Plugging and abandonment*" Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface. Regulations of all states require plugging of abandoned wells.

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"*Probable reserves*" Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(a) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

(b) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

(c) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

"*Producing property*" A oil and natural gas property with existing production.

"*Productive wells*" Producing wells and wells mechanically capable of production.

"*Proppant*" Sized particles mixed with fracturing fluid to hold fractures open after a hydraulic fracturing treatment. In addition to naturally occurring sand grains, man-made or specially engineered proppants, such as resin-coated sand or high-strength ceramic materials like sintered bauxite, may also be used. Proppant materials are carefully sorted for size and sphericity to provide an efficient conduit for production of fluid from the reservoir to the wellbore.

"*Proved developed producing*" Proved developed reserves that can be expected to be recovered from a reservoir that is currently producing through existing wells.

"*Proved developed reserves*" Proved gas and oil that are also developed gas and oil reserves.

"*Proved oil and gas reserves*" Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geosciences and engineering data, can be estimated with reasonable certainty to be economically producible-from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations-prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. Also referred to as "proved reserves."

"*Proved undeveloped reserves*" Proved oil and gas reserves that are also undeveloped oil and gas reserves.

"*PUD*" Proved undeveloped drilling locations.

"*Reasonable certainty*" A high degree of confidence.

"*Recompletion*" Redrilling a well to a new producing zone (new depth) when the current zone is depleted.

"*Refrac*" Application of additional fracture stimulation to increase production from wells that have been previously fracture stimulated.

"*Reserves*" Estimated quantities of oil and natural gas and related substances anticipated to be economically producible as of a given date by application of development prospects to known accumulations.

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

"*Royalty interest*" An interest in a oil and natural gas property entitling the owner to a share of oil or gas production free of production costs.

"*Unconventional reservoirs*" A term used in the oil and natural gas industry to refer to a play in which the targeted reservoirs generally fall into one of three categories: (1) tight sands, (2) coal beds, or (3) gas shales. The reservoirs tend to cover large areas and lack the readily apparent traps, seals and discrete hydrocarbon-water boundaries that typically define conventional reservoirs. These reservoirs generally require fracture stimulation treatments or other special recovery processes in order to produce economic flow rates.

"*Undeveloped acreage*" Those leased acres on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil or gas regardless of whether such acreage contains proved reserves.

"*Undeveloped oil and gas reserves*" Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Also referred to as "undeveloped reserves."

"*Well spacing*" The regulation of the number and location of wells over an oil or gas reservoir, as a conservation measure. Well spacing is normally accomplished by order of the regulatory conservation commission in the applicable jurisdiction. The order may be statewide in its application (subject to change for local conditions) or it may be entered for each field after its discovery. In the operational context, "well spacing" refers to the area attributable between producing wells within the scope of what is permitted under a regulatory order.

"*Wellbore*" The hole drilled by the bit that is equipped for oil or gas production on a completed well. Also called well or borehole.

"*Working interest*" The right granted to the lesee of a property to explore for and to produce and own oil and gas. The working interest owner bears the exploration, development and operating costs of the property.

"*WTI*" West Texas Intermediate, the benchmark crude oil in the United States.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors
Bonanza Creek Energy, Inc.

We have audited the accompanying consolidated balance sheet of Bonanza Creek Energy, Inc. and subsidiaries (the "Company") as of December 31, 2010 and the related statements of operations, stockholders' equity and cash flows for the period from inception (December 23, 2010) to December 31, 2010. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above presents fairly, in all material respects, the consolidated financial position of Bonanza Creek Energy, Inc. and its subsidiaries as of December 31, 2010 and the results of their operations and cash flows for the period from inception (December 23, 2010) to December 31, 2010 in conformity with accounting principles generally accepted in the United States of America.

HEIN & ASSOCIATES LLP

Denver, Colorado
July 21, 2011

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BONANZA CREEK ENERGY, INC.

CONSOLIDATED BALANCE SHEET

AS OF DECEMBER 31, 2010

ASSETS	
CURRENT ASSETS:	
Cash and cash equivalents	$
Accounts receivable:	
Oil and gas sales	8,894,831
Other	2,940,590
Prepaid expenses and other	703,063
Inventory of oilfield equipment	415,650
Derivative asset	1,396,472
Total current assets	14,350,606
OIL AND GAS PROPERTIES using the successful efforts method of accounting	
Proved properties	441,303,069
Unproved properties	14,749,117
Wells in progress	8,387,164
	464,439,350
Less: accumulated depreciation, depletion and amortization	(470,390)
	463,968,960
NATURAL GAS PLANT	31,840,475
Less: accumulated depreciation	(20,017)
	31,820,458
PROPERTY AND EQUIPMENT	802,679
Less: accumulated depreciation	(10,008)
	792,671
LONG-TERM DERIVATIVE ASSET	2,045,182
OTHER ASSETS	3,125,670
TOTAL ASSETS	$ 516,103,547
LIABILITIES AND STOCKHOLDERS' EQUITY	
CURRENT LIABILITIES:	
Accounts payable and accrued expenses	$ 16,101,536
Oil and gas revenue distribution payable	3,444,077
Derivative liability	3,691,998
Total current liabilities	23,237,611

LONG-TERM LIABILITIES:	
Bank revolving credit	55,400,000
Ad valorem taxes	1,213,445
Derivative liability	5,854,980
Deferred income taxes, net	68,405,393
Asset retirement obligations	5,611,709
TOTAL LIABILITIES	159,723,138
COMMITMENTS AND CONTINGENCIES (Notes 7 and 10)	
STOCKHOLDERS' EQUITY:	
Common stock, Class A, $.001 par value, 99,990,000 shares authorized, 29,122,521 issued and outstanding	29,123
Common stock, Class B, $.001 par value, 10,000 shares authorized, 7,500 issued and outstanding	
Additional paid-in capital	356,513,012
Accumulated deficit	(161,726)
Total stockholders' equity	356,380,409
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 516,103,547

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BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF OPERATIONS

FOR THE PERIOD FROM INCEPTION (DECEMBER 23, 2010) TO DECEMBER 31, 2010

NET REVENUES:		
Oil and gas sales	$	1,745,415
OPERATING EXPENSES:		
Lease operating		482,828
Severance and ad valorem taxes		69,889
Depreciation, depletion and amortization		506,307
General and administrative		323,545
Total operating expenses		1,382,569
INCOME FROM OPERATIONS		362,846
OTHER INCOME (EXPENSE):		
Realized loss on settled commodity derivatives		(46,742)
Unrealized loss in fair value of commodity derivatives		(514,627)
Interest expense		(57,656)
Total other expense		(619,025)
LOSS BEFORE TAXES		(256,179)
Deferred tax benefit		94,453
NET (LOSS)	$	(161,726)
BASIC AND DILUTED LOSS PER SHARE	$	(0.01)
WEIGHTED AVERAGE NUMBER OF SHARES OF COMMON STOCK BASIC AND DILUTED		29,122,521

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BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY

FOR THE PERIOD FROM INCEPTION (DECEMBER 23, 2010) TO DECEMBER 31, 2010

	Common Stock A Shares		Common Stock B Shares		Additional Paid-In Capital	Accumulated Deficit	Total
	Shares	Amount	Shares	Amount			
BALANCES at December 23, 2010					$	$	$
Contribution of capital	29,122,521	$ 29,123	7,500	$	356,513,012		356,542,135
Net (loss)						(161,726)	(161,726)
BALANCES at December 31, 2010	29,122,521	$ 29,123	7,500	$	$ 356,513,012	$ (161,726)	$ 356,380,409

BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF CASH FLOWS

FOR THE PERIOD FROM INCEPTION (DECEMBER 23, 2010) TO DECEMBER 31, 2010

CASH FLOWS FROM OPERATING ACTIVITIES:		
Net (loss)	$	(161,726)
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization		506,307
Deferred income taxes		(94,453)
Amortization of deferred financing costs		15,589
Valuation decrease in commodity derivatives		514,627
Increase in operating assets:		
Accounts receivable		(2,104,097)
Decrease in operating liabilities:		
Accounts payable and accrued expenses		(309,076)
Net cash (used) by operating activities		(1,632,829)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Exploration and development of oil and gas properties		(817,362)
Net cash used in investing activities		(817,362)
NET DECREASE IN CASH AND CASH EQUIVALENTS		(2,450,191)
CASH AND CASH EQUIVALENTS:		
Beginning of period		2,450,191
End of year	$	
SUPPLEMENTAL CASH FLOW DISCLOSURE:		
Cash paid for interest	$	
Cash paid for income taxes	$	
Value of stock issued to members of BCEC and HEC	$	99,613,966

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Bonanza Creek Energy, Inc.

Notes to the Consolidated Financial Statements as of December 31, 2010

1. ORGANIZATION AND BUSINESS:

On December 23, 2010, Bonanza Creek Energy, Inc. (a Delaware C corporation) (the "Company" or BCEI) was formed in conjunction with the following transactions which were accomplished simultaneously:

(1) The contribution by Bonanza Creek Energy Company, LLC (BCEC) of all of its ownership in Bonanza Creek Energy Operating Company, LLC (a wholly owned subsidiary) to BCEI and assumption by BCEI of BCEC's remaining debt (as described below) in exchange for a 21.55% ownership interest of BCEI. BCEC had no other significant assets or subsidiaries at such time. BCEC was an operating oil and gas company that was initially founded in 2006;

(2) The sale of $265 million of common stock of BCEI which constituted an ownership interest of 72.68% of BCEI 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"); and

(3) The exchange of shares of 5.77% of BCEI's common stock together with $59 million in cash (which came from the $265 million sale of common stock of BCEI described in (2) above), for all of the equity interests of Holmes Eastern Company, LLC (HEC), a Limited Liability Company that was majority owned by a minority member of Bonanza Creek Oil Company, LLC (BCOC). BCOC was the predecessor of BCEC and owned 29.9% of BCEC on a fully diluted basis at the time of such transaction. HEC was initially formed in 2009 and has been an operating oil and gas exploration and production business since its formation.

The BCEC ownership (21.55%) of BCEI was distributed to or for the benefit of BCEC's members based on management's estimate of fair value of the BCEI shares received by BCEC to holders of the equity interests of BCEC in connection with the redemption of BCEC's equity and BCEC's dissolution to:

(1) BCOC in the amount of 5.5% (for its Series A Units of BCEC);

(2) D.E. Shaw Laminar Portfolios, L.L.C. (Laminar) in the amount of 12.91% (for its Series A Units of BCEC); and

(3) The management of BCEC, in the amount of 3.14% (for their Series B Units of BCEC).

Cash proceeds of approximately $182 million were used to retire BCEC's second lien term loan, senior subordinated notes and a related party note payable, and to reduce the outstanding principal balance on BCEC's bank revolving credit facility by $29 million thereby reducing the balance outstanding to approximately $55.4 million as of December 31, 2010. This loan at the same time was assumed by BCEI.

The Company is engaged primarily in acquiring, developing, exploiting and producing oil and gas properties. As of December 31, 2010, the Company's assets and operations are concentrated primarily in southern Arkansas and in the Denver Julesburg and North Park Basins in the Rocky Mountains.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

Principles of Consolidation The consolidated balance sheet includes the accounts of the Company and its wholly owned subsidiaries, Bonanza Creek Energy Operating Company, LLC, Bonanza Creek Energy Resources Company, LLC and HEC. All significant intercompany accounts and transactions have been eliminated.

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Bonanza Creek Energy, Inc.

Notes to the Consolidated Financial Statements as of December 31, 2010 (Continued)

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES: (Continued)

Fair Value of Financial Instruments The Company's financial instruments consist of trade receivables, trade payables, accrued liabilities, long-term debt and derivative instruments.

Use of Estimates The preparation of this balance sheet in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of oil and gas reserves, assets and liabilities and disclosure of contingent assets and liabilities at the date of the balance sheet and the reported amounts of revenue and expenses during the reporting period. Actual results could differ from those estimates.

Cash and Cash Equivalents The Company considers all highly liquid investments with original maturity dates of three months or less to be cash equivalents.

Accounts Receivable Trade accounts receivable are recorded at net realizable value which is estimated to be fair value at December 31, 2010. If the financial condition of the Company's customers were to deteriorate, resulting in an impairment of their ability to make payments, additional allowances may be required. Delinquent trade accounts receivable are charged against the allowance for doubtful accounts once collectibility has been determined.

The Company's crude oil and natural gas receivables are generally collected within two months. The Company accrues an allowance on a receivable when, based on the judgment of management, it is probable that a receivable will not be collected and the amount of any allowance may be reasonably estimated.

Inventory of Oilfield Equipment Inventory consists of material and supplies used in connection with the Company's drilling program. These inventories are stated at the lower of average cost or market which as of December 31, 2010 approximated fair value.

Oil and Gas Producing Activities The Company follows the successful efforts method of accounting for its oil and gas properties. Under this method of accounting, all property acquisition costs and costs of exploratory and development wells will be capitalized at cost when incurred, pending determination of whether the well has found proved reserves. If an exploratory well has not found proved reserves, the costs of drilling the well and other associated costs will be charged to expense. The costs of development wells will be capitalized whether productive or nonproductive. Costs incurred to maintain wells and related equipment and lease and well operating costs are charged to expense as incurred. Gains and losses arising from sales of properties will be included in income. However, sales that do not significantly affect a field's unit-of-production depletion rate will be accounted for as normal retirements with no gain or loss recognized. Geological and geophysical costs of exploratory prospects and the costs of carrying and retaining unproved properties are expensed as incurred.

Depletion, depreciation and amortization (DD&A) of capitalized costs of proved oil and gas properties are provided for on a field-by-field basis using the units of production method based upon proved reserves. The computation of DD&A takes into consideration the anticipated proceeds from equipment salvage and the Company's expected cost to abandon its well interests.

The Company assesses its proved oil and gas properties for impairment whenever events or circumstances indicate that the carrying value of the assets may not be recoverable. The impairment test compares undiscounted future net cash flows to the assets' net book value. If the net capitalized costs

Bonanza Creek Energy, Inc.

Notes to the Consolidated Financial Statements as of December 31, 2010 (Continued)

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES: (Continued)

exceed future net cash flows, then the cost of the property will be written down to "fair value." Fair value for oil and natural gas properties is generally determined based on discounted future net cash flows.

The Company will record the fair value of a liability for an asset retirement obligation as an asset and a liability when there is a legal obligation associated with the retirement of a long-lived asset and the amount can be reasonably estimated. As of December 23, 2010 this liability was recorded based on its estimated fair value. Refer also to Note 10 relating to asset retirement obligations, which includes additional information on the Company's asset retirement obligations.

Long-Lived Assets Long-lived assets to be held and used or disposed of other than by sale are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. When required, impairment losses on assets to be held and used or disposed of other than by sale are recognized based on the fair value of the asset. Long-lived assets to be disposed of by sale are reported at the lower of their carrying amount or fair value less cost to sell. As of December 23, 2010, long-lived assets were recorded at management's estimate of fair value.

Other Property and Equipment Property and equipment are recorded at fair value as of December 23, 2010. Property additions subsequent to December 23, 2010 have been recorded at cost. Depreciation will be calculated using the straight-line method over the estimated useful lives of the assets, which range from three to ten years.

Revenue Recognition The Company records revenues from the sales of crude oil and natural gas when delivery to the customer has occurred and title has transferred, net of royalties, discounts and allowances, as applicable. This occurs when oil or gas has been delivered to a pipeline or a tank lifting has occurred. The Company has interests with other producers in certain properties in which case the Company uses the entitlement method to account for gas imbalances. There were no gas imbalances as of December 31, 2010.

For gathering and processing services, the Company either receives fees or commodities from natural gas producers depending on the type of contract. Under the percentage-of-proceeds contract type, the Company is paid for its services by keeping a percentage of the natural gas liquids (NGL) produced and a percentage of the residue gas resulting from processing the natural gas. Commodities received are, in turn, sold and recognized as revenue in accordance with the criteria outline above.

Income Taxes The Company accounts for income taxes under the liability method, which requires recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the balance sheet or tax returns. Deferred tax assets and liabilities were determined based on the difference between the fair value of the assets acquired and liabilities assumed as compared to their tax bases of assets and liabilities using enacted tax rates in effect.

Concentrations of Credit Risk The Company has maintained cash balances in excess of the Federal Deposit Insurance Corporation (FDIC) insured limit.

For the period from inception (December 23, 2010) to December 31. 2010, Lion Oil Trading & Transport and Plains Marketing accounted for 52% and 30%, respectively, of oil and natural gas sales.

Risks and Uncertainties Historically, oil and gas prices have experienced significant fluctuations and have been particularly volatile in recent years. Price fluctuations can result from variations in weather,

Bonanza Creek Energy, Inc.

Notes to the Consolidated Financial Statements as of December 31, 2010 (Continued)

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES: (Continued)

levels of regional or national production and demand, availability of transportation capacity to other regions of the country and various other factors.

Oil and Gas Derivative Activities The Company recognizes all derivative instruments on the balance sheet as either assets or liabilities at fair value.

The Company is exposed to commodity price risk related to oil and gas prices. To mitigate this risk, the Company enters into oil and gas forward contracts as economic hedges. The contracts, which are generally placed with major financial institutions or with counter parties which management believes to be of high credit quality, may take the form of futures contracts, swaps or options. The oil and gas reference prices of these contracts are based upon oil and natural gas futures, which have a high degree of historical correlation with actual prices received by the Company.

Adopted and Recently Issued Accounting Pronouncements The Company follows the provisions of FASB ASC 740, *Accounting for Uncertainty in Income Taxes*. The statement does not have a material effect on the Company's financial position. The Company recognizes interest and penalties related to uncertain tax positions in income tax expense. The Company files income tax returns in the U.S. federal jurisdiction and various states. The tax return for December 31, 2010 has not yet been filed and the Company has not taken any uncertain tax positions.

In December 2010, the FASB issued Accounting Standards Update No. 2010-29, *Business Combinations: Disclosure of Supplementary Pro Forma Information for Business Combinations* (ASU 2010-29), which provides amendments to FASB ASC Topic 805, *Business Combinations*. The objective of ASU 2010-29 is to clarify and expand the pro forma revenue and earnings disclosure requirements for business combinations. ASU 2010-29 is effective for fiscal years beginning after December 15, 2010. The adoption of this standard will not have an impact on the Company's consolidated balance sheet other than additional disclosures.

In January 2010, the FASB issued Accounting Standards Update No. 2010-06, *Improving Disclosures about Fair Value Measurements* (ASU 2010-06), which provides amendments to FASB ASC Topic 820, *Fair Value Measurements and Disclosures.* The objective of ASU 2010-06 is to provide more robust disclosures about (i) the different classes of assets and liabilities measured at fair value, (ii) the valuation techniques and inputs used, (iii) the activity in Level 3 fair value measurements, and (iv) significant transfers between Levels 1, 2 and 3. ASU 2010-06 was effective for fiscal years and interim periods beginning after December 15, 2009, except for the activity in Level 3 measurement disclosures which is effective January 1, 2011. The Company adopted ASU 2010-06 effective December 31, 2010, which did not have an impact on its consolidated balance sheet, other than additional disclosures.

In December 2008, the SEC issued *Modernization of Oil and Gas Reporting: Final Rule,* which published the final rules and interpretations updating its oil and gas reporting requirements. The final rule includes updates to definitions in the existing oil and gas rules to make them consistent with the petroleum resource management system, which is a widely accepted standard for the management of petroleum resources that was developed by several industry organizations. Key revisions include the ability to include nontraditional resources in reserves, the use of new technology for determining reserves, permitting disclosure of probable and possible reserves, and changes to the pricing used to determine reserves in that companies must use a 12-month average price. The average is calculated using the first-day-of-the-month price for each of the 12 months that make up the reporting period. In January 2010, the FASB issued Accounting Standards Update No. 2010-03, *Oil and Gas Reserve Estimation and Disclosures* (ASU

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Bonanza Creek Energy, Inc.

Notes to the Consolidated Financial Statements as of December 31, 2010 (Continued)

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES: (Continued)

2010-03), which provides amendments to FASB ASC topic *Extractive Activities-Oil and Gas.* The objective of ASU 2010-03 is to align the oil and gas reserve estimation and disclosure requirements of the FASB ASC with the requirements in the SEC's *Modernization of Oil and Gas Reporting: Final Rule*. BCEC and HEC, the predecessor companies adopted the new rules effective December 31, 2009, and as a result, the Company's December 31, 2010 acquisition reserves were prepared in accordance with the new reserve definitions in ASU 2010-03 that conform to the SEC's revised reserve definitions, and reported proved undeveloped reserve quantities in Disclosure About Oil and Gas Producing Activities. Oil and gas reserve quantities or their values are a significant component of the Company's depreciation, depletion and amortization, asset retirement obligation, and proved property impairment analyses. Due to the number of estimates that rely upon reserve quantities and values, any significant changes to the Company's oil and gas reserves has a pervasive effect on the Company's consolidated balance sheet, and it is therefore impracticable to estimate the effect that the adoption of ASU 2010-03 had on the Company's consolidated balance sheet.

3. ACQUISITIONS:

On December 23, 2010, the Company completed the following transactions: (i) the sale of 21,166,134 shares of common stock for $12.52 per share; (ii) the issuance of 6,272,851 shares of common stock valued at $12.52 per share to the holders of BCEC in exchange for all of BCEC's ownership in Bonanza Creek Energy Operating Company, LLC (a wholly owned subsidiary); and (iii) the acquisition of all of the ownership of HEC for approximately $59 million in cash and 1,683,536 shares of its common stock valued at $12.52 per share. As part of the transactions, the Company also retired debt of approximately $182 million for cash and paid approximately $17 million for debt extinguishment penalties assumed as part of the merger. Because the penalties for the extinguishment of debt were considered as part of the liabilities assumed, the penalties were allocated to the assets acquired and the liabilities assumed as part of the purchase price. Furthermore, a deferred tax liability was recorded based on the difference between the

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Bonanza Creek Energy, Inc.

Notes to the Consolidated Financial Statements as of December 31, 2010 (Continued)

3. ACQUISITIONS: (Continued)

tax basis of the contributed assets and liabilities and their fair value at an effective tax rate of approximately 37%. Fair value was allocated to the assets contributed and liabilities assumed as follows:

	Bonanza Creek Energy Company, LLC	Holmes Eastern Company, LLC	Debt Extinguishment	Deferred Tax Adjustment	Bonanza Creek Energy, Inc.
Current assets, including cash and commodity derivatives	$ 10,917,445	$ 3,848,328	$	$	$ 14,765,773
Proved oil and gas properties	280,831,550	77,985,048	16,680,311	65,711,707	441,303,069
Unproved oil and gas properties	11,376,727		678,704	2,693,686	14,749,117
Wells in progress	5,782,885	1,786,917			7,569,802
Natural gas plant	31,840,475				31,840,475
Property and equipment	777,564	25,115			802,679
Other noncurrent assets, including commodity derivatives	5,357,346				5,357,346
Current liabilities, including commodity derivatives	(19,894,250)	(3,559,307)			(23,453,557)
Bank revolving credit	(84,400,000)		29,000,000		(55,400,000)
Senior subordinated notes	(125,145,205)		125,145,205		
Second lien term loan, including pre-payment penality of $3,031,667	(33,031,667)		33,031,667		
Note payable related party	(12,276,228)		12,276,228		
Commodity derivatives	(5,673,460)				(5,673,460)
Deferred income taxes, net				(68,405,393)	(68,499,846)
Other noncurrent liabilities, including asset retirement obligations	(5,917,784)	(901,479)			(6,819,263)
Value of common stock issued as consideration	60,545,398	79,184,622	216,812,115		356,542,135

Supplemental Pro Forma Results (unaudited) The following unaudited pro forma financial information represents the combined results for BCEC and HEC for year ended December 31, 2010 as if the contribution and acquisition had occurred on January 1, 2010. In connection with the Company's payoff and retirement of BCEC's senior subordinated notes and the second lien term loan early termination fees were paid in the amount of $14,327,348 and $3,031,667, respectively. These early termination payments were considered a component of the acquisition of BCEC and not reflected in the pro forma below. These pro forma adjustments assume such obligations were paid off and retired on January 1, 2010, the adjustment to depreciation, depletion and amortization assumes that the oil and gas property step up in basis occurred January 1, 2010.

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Bonanza Creek Energy, Inc.

Notes to the Consolidated Financial Statements as of December 31, 2010 (Continued)

3. ACQUISITIONS: (Continued)

The pro forma financial information is not intended to represent or be indicative of the consolidated results of operations or financial condition of the Company that would have been reported had the acquisition been completed as of the dates presented, and should not be taken as representative of the future consolidated results of operations of the Company.

	Bonanza Creek Energy Company, LLC	Holmes Eastern Company, LLC	Bonanza Creek Energy, Inc.	Pro Forma Adjustments	Bonanza Creek Energy, Inc.
Net revenues:					
Oil and gas sales	$ 48,328,094	$ 13,957,560	$ 1,745,415	$	$ 64,031,069
Operating expenses:					
Lease operating	14,791,785	2,010,187	482,828		17,284,800
Severance and ad valorem taxes	1,620,495	834,282	69,889		2,524,666
Exploration	360,742	19,234			379,976
Depreciation, depletion and amortization	14,225,309	3,005,888	506,307	3,179,496	20,917,000
General and administrative	8,374,875	639,598	323,545		9,338,018
Cancelled private placement	2,378,468				2,378,468
Total operating expenses	41,751,674	6,509,189	1,382,569	3,179,496	52,822,928
Income from operations	6,576,420	7,448,371	362,846	(3,179,496)	11,208,141
Other income (expense):					
Gain on sale of oil and gas properties	4,055,153				4,055,153
Other income (loss)	19,173	(65,694)			(46,521)
Write-off of deferred financing costs	(1,663,167)				(1,663,167)
Change in fair value of warrant put option	34,344,894			(34,344,894)	
Amortization of debt discount	(8,861,955)			8,861,955	
Realized gain on settled commodity derivatives	5,918,702		(46,742)		5,871,960
Unrealized loss in fair value of commodity derivatives	(7,604,742)		(514,627)		(8,119,369)
Interest expense	(18,000,796)	(439,171)	(57,656)	17,234,623	(1,263,000)
Total other income (expense)	8,207,262	(504,865)	(619,025)	(8,248,316)	(1,164,944)
Income before taxes	$ 14,783,682	$ 6,943,506	$ (256,179)	$ (11,427,812)	$ 10,043,197

The following table sets forth certain unaudited pro forma information concerning BCEI's proved oil and gas reserves giving effect to the acquisition of HEC properties and the reorganization of BCEC into BCEI as if they had occurred on January 1, 2010. The following estimates of proved oil and gas reserves, both developed and undeveloped, represent interests acquired by BCEI in the transaction described above,

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Bonanza Creek Energy, Inc.

Notes to the Consolidated Financial Statements as of December 31, 2010 (Continued)

3. ACQUISITIONS: (Continued)

and are located solely within the United States. Proved reserves represent estimated quantities of crude oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed oil and gas reserves are the quantities expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells for which relatively major expenditures are required for completion.

The estimate of proved reserves and related valuations for the year ended December 31, 2009 and 2010 were based upon a report prepared by Cawley, Gillespie & Associates, Inc. Petroleum Consultants. The estimates of proved reserves are inherently imprecise and are continually subject to revision based on production history, results of additional exploration and development, price changes and other factors. These estimates do not include probable or possible reserves. The information provided does not represent BCEI's estimate of expected future cash flows or value of proved oil and gas reserves.

Changes in estimated reserve quantities:

	Oil (MBbl)			Natural Gas (MMcf)		
	Bonanza Creek Energy Company, LLC	Holmes Eastern Company, LLC	Pro Forma Combined	Bonanza Creek Energy Company, LLC	Holmes Eastern Company, LLC	Pro Forma Combined
Balance December 31, 2009	15,270	6,118	21,388	27,610	16,565	44,175
Extensions and discoveries	2,250	183	2,433	5,023	744	5,767
Sales of minerals in place	(568)		(568)			
Production	(611)	(141)	(752)	(1,335)	(797)	(2,132)
Revisions to previous estimates	319	(441)	(122)	9,900	5,174	15,074
Balance December 31, 2010	16,660	5,719	22,379	41,198	21,686	62,884
Proved developed reserves:						
December 31, 2009	4,710	1,292	6,002	7,021	5,346	12,367
December 31, 2010	6,449	1,731	8,180	13,677	6,397	20,074
Proved undeveloped reserves						
December 31, 2009	10,560	4,826	15,386	20,589	11,219	31,808
December 31, 2010	10,211	3,988	14,199	27,521	15,289	42,810

The following table sets forth unaudited pro forma information concerning the discounted future net cash flows from proved oil and gas reserves of BCEI as of December 31, 2010, net of income tax expense, and giving effect to the acquisition of the HEC properties and the reorganization of BCEC into BCEI as if they had occurred on January 1, 2010. Future income tax expenses are calculated by applying appropriate year-end tax rates to future pretax net cash flows relating to proved oil and natural gas reserves. Future income tax expenses give effect to permanent differences, tax credits and loss carryforwards relating to the proved oil and natural gas reserves. Future net cash flows are discounted at a rate of 10% annually to derive the standardized measure of discounted future net cash flows. This calculation procedure does not

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Bonanza Creek Energy, Inc.

Notes to the Consolidated Financial Statements as of December 31, 2010 (Continued)

3. ACQUISITIONS: (Continued)

necessarily result in an estimate of the fair market value or the present value of BCEI's oil and natural gas properties.

Standardized measure of discounted future net cash flows from estimated production of proved oil and gas reserves (in thousands) as of December 31, 2010:

	Bonanza Creek Energy Company, LLC	Holmes Eastern Company, LLC	Pro Forma Combined
Future cash flows	$ 1,365,714	$ 528,463	$ 1,894,177
Future production costs	(434,148)	(138,406)	(572,554)
Future development costs	(221,190)	(130,202)	(351,392)
Future income tax expense	(126,005)	(57,242)	(183,247)
Future net cash flows	584,371	202,613	786,984
10% annual discount for estimated timing of cash flows	(299,267)	(112,942)	(412,209)
Standardized measure of discounted future net cash flows	$ 285,104	$ 89,671	$ 374,775

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

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

	Bonanza Creek Energy Company, LLC	Holmes Eastern Company, LLC	Pro Forma Combined
Beginning of year	$ 185,704	$ 58,150	$ 243,854
Sale of oil and gas produced, net of production costs	(32,809)	(11,412)	(44,221)
Net changes in prices and production costs	97,702	42,509	140,211
Extensions, discoveries and improved recoveries	45,497	4,641	50,138
Development costs incurred	21,615	9,342	30,957
Changes in estimated development cost	(30,350)	(14,006)	(44,356)
Sales of mineral in place	(10,972)		(10,972)
Revisions of previous quantity estimates	38,059	7,793	45,852
Net change in income taxes	(38,938)	(10,041)	(48,979)
Accretion of discount	20,824	7,344	28,168
Changes in production rates and other	(11,228)	(4,649)	(15,877)
End of year	$ 285,104	$ 89,671	$ 374,775

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Bonanza Creek Energy, Inc.

Notes to the Consolidated Balance Sheet as of December 31, 2010

3. ACQUISITIONS: (Continued)

Average wellhead prices inclusive of adjustments for quality and location used in determining future net revenues related to the standardized measure calculation as of December 31, 2010 were calculated using the first-day-of-the-month price for each of the 12 months that made up the reporting period.

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

4. OTHER ASSETS:

Other assets include the following:

The Company has multiple certificates of deposit at three financial institutions to meet financial bonding requirements in the states of Colorado, Wyoming and California. As of December 31, 2010 the certificate of deposits totaled $645,000.

As of December 31, 2010, the Company had a note receivable of approximately $987,000 from the operator of the Sargent field and was paid in full during February of 2011.

As of December 31, 2010, the Company had approximately $1,494,000 of unamortized deferred financing costs related to the bank revolving credit agreement that was retained by the Company.

Certificates of deposit	$ 645,000
Note receivable	986,906
Deferred financing cost	1,493,764
	$ 3,125,670

5. ACCOUNTS PAYABLE AND ACCRUED EXPENSES:

Accounts payable and accrued expenses contain the following:

	2010
Drilling and completion costs	$ 4,597,857
Accounts payable trade	6,213,962
Ad valorem taxes	1,373,548
Accrued general and administrative cost	1,608,995
Lease operating expense	1,240,481
Accrued reclamation cost	400,000
Interest	106,034
Accrued oil and gas hedging	244,527
Production taxes and other	316,132
	$ 16,101,536

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Bonanza Creek Energy, Inc.

Notes to the Consolidated Balance Sheet as of December 31, 2010

6. LONG-TERM DEBT:

Senior Secured Revolving Credit Facility On May 7, 2010, Bonanza Creek Energy Operating Company, LLC, previously a wholly owned subsidiary of BCEC, and now a wholly owned subsidiary of the Company entered into a Senior Secured Revolving Credit Agreement, (the "Revolver"), with a syndication of banks with BNP Paribas as the administrative agent and issuing lender, which provides for borrowings of up to $200 million. The Revolver provides for interest rates plus an applicable margin to be determined based on LIBOR or a bank base rate (the "Base Rate"), at the Company's election. LIBOR borrowings bear interest at LIBOR plus 2.25% to 3.00% depending on the utilization level and the Base Rate borrowings bear interest at the "Bank Prime Rate," as defined plus 1.25% to 2.00%.

During March of 2011, the Company entered into a new $300 million Senior Secured Revolving Credit Agreement with an initial borrowing base of $130 million with a syndicate of banks led by BNP Paribas. As of December 31, 2010 the credit facility had a balance of $55,400,000.

The Revolver has a $130 million borrowing base as of March 31, 2011 and is subject to semi-annual re-determinations in April and October of each year. The Revolver provides for commitment fees of 0.5% and restricts, among other items, the payment of dividends, certain additional indebtedness, sale of assets, loans, certain investments and mergers. The Revolver also contains certain financial covenants, which require the maintenance of a minimum current ratio and a minimum debt coverage ratio, as defined. The Company was in compliance with these covenants as of March 31, 2011. The Revolver is collateralized by substantially all the Company's assets and matures on March 29, 2015.

7. COMMITMENTS AND CONTINGENT LIABILITIES:

Office Leases The Company rents office facilities under various noncancelable operating lease agreements. The Company's noncancelable operating lease agreements result in total future minimum noncancelable lease payments are presented below. The Company also has principal payment requirements for its line of credit which is also presented below:

	Office Leases	Line of Credit	Total
2011	$ 347,437	$	$ 347,437
2012	294,934		294,934
2013	298,873	55,400,000	55,698,873
2014	305,438		305,438
2015 and thereafter	462,591		462,591
	$ 1,709,273	$ 55,400,000	$ 57,109,273

Environmental The Company is engaged in oil and gas exploration and production and may become subject to certain liabilities as they relate to environmental cleanup of well sites or other environmental restoration procedures as they relate to the drilling of oil and gas wells and the operations. In the Company's acquisition of existing or previously drilled well bores, the Company may not be aware of what environmental safeguards were taken at the time such wells were drilled or during such time the wells were operated. Should it be determined that a liability exists with respect to any environmental clean up or restoration, the liability to cure such a violation could fall upon the Company. Management believes its properties are operated in conformity with local, state and federal regulations. No claim has been made, nor is the Company aware of any uninsured liability which the Company may have, as it relates to any environmental cleanup, restoration or the violation of any rules or regulations.

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Bonanza Creek Energy, Inc.

Notes to the Consolidated Balance Sheet as of December 31, 2010

7. COMMITMENTS AND CONTINGENT LIABILITIES: (Continued)

Legal Proceeding The Company may from time to time be involved in various other legal actions arising in the normal course of business. In the opinion of management, the Company's liability, if any, in these pending actions would not have a material adverse effect on the financial positions of the Company. The Company's general and administrative expenses would include amounts incurred to resolve claims made against the Company.

8. STOCKHOLDERS' EQUITY:

Common Stock On December 23, 2010 the Company was formed by the issuance of 21,166,134 shares of common stock to West Face Capital and to certain clients of AIMCo at $12.52 per share. Also as part of the formation on December 23, 2010 BCEC contributed all of its ownership interest in Bonanza Creek Energy Operating Company, LLC to the Company for 6,272,851 shares of its common stock valued at $12.52 per share. On December 23, 2010, the Company issued 1,683,536 shares of its common stock valued at $12.52 per share to the majority owner of HEC and a member of Bonanza Creek Energy, Inc's management who also owned a minority interest of HEC (refer to Note 3).

Management Incentive Plan On December 23, 2010, the Company established the Management Incentive Plan (the "Plan" or MIP) for the benefit of certain employees, officers and other individuals performing services for the Company. The maximum number of shares of Class B common stock available under the Plan is 10,000. Such shares will be converted into Class A common stock upon a liquidity event. The conversion rate is determined based on formula factoring in the rate of return to the Class A common stockholders. As of December 31, 2010, the Company issued 7,500 shares from the Plan and the fair value of each share was determined to be $1.60.

The related compensation expense is immaterial to the financial statements. Compensation expense will be recognized in BCEI's statement of operations when the unissued Class B common stock is granted to employees.

BCEC Management Incentive Plan In connection with the recapitalization described in Note 1, the remaining unissued Class B member units were converted into 317,142 shares of Class A common stock of BCEI. These shares are being held in trust for the benefit of employees. When the shares are released and employees are notified of the award, compensation expense will be recorded on BCEI's statement of operations.

9. INCOME TAXES:

During the period ended December 31, 2010, the net deferred tax liabilities increased by $68.4 million related to the formation of the Company. The $68.4 million net deferred tax liabilities represent the basis differences between financial reporting assets and liabilities and tax basis of assets and liabilities.

In assessing the realizability of deferred tax assets, management considers whether it is more-likely-than-not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities, projected future results of operations, and tax planning strategies in making this assessment.

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Bonanza Creek Energy, Inc.

Notes to the Consolidated Balance Sheet as of December 31, 2010

9. INCOME TAXES: (Continued)

The Company adopted the applicable provisions of ASC 740 to recognize, measure, and disclose uncertain tax positions in the financial statements. Under ASC 740, tax positions must meet a more-likely-than-not recognition threshold at the effective date to be recognized upon the adoption and in subsequent periods. As of December 31, 2010, the Company has no uncertain tax benefits.

The Company recognizes interest and penalties related to uncertain tax positions in income tax (benefit)/expense. No interest and penalties related to uncertain tax positions were accrued as of December 31, 2010.

The 2010 tax period for federal and state returns have not been filed and remains open to examination by the major taxing jurisdictions in which the Company operates. There are currently no federal or state examinations.

The Company's deferred tax assets and liabilities consist of the following at December 31, 2010:

Tax Assets:		
Derivative liability	$	2,250,832
Asset retirement obligation		1,921,385
Total tax assets		4,172,217
Tax Liabilities:		
Property and equipment		72,577,610
Net deferred tax liability	$	68,405,393

Reconciliation of the Company's effective tax rate to the expected federal tax rate of 34% is as follows: Expected federal tax rate	34%
State income tax rate, net of federal benefit	2.87%
Effective tax rate	36.87%

10. ASSET RETIREMENT OBLIGATIONS:

In connection with the Company's acquisition of BCEC and HEC, asset retirement obligations in the amount of $4,970,441, and $641,268, respectively, were assumed. The value of the asset retirement obligations assumed as of December 31, 2010, approximates the fair value of these obligations.

11. FAIR VALUE MEASUREMENTS:

The Company follows FASB ASC 820, *Fair Value Measurements and Disclosures*, which defines fair value, establishes a framework for using fair value to measure assets and liabilities, and expands disclosures about fair value measurements. The statement establishes a hierarchy for inputs used in measuring fair value that maximizes the use of observable inputs and minimizes the use of unobservable inputs by requiring that the most observable inputs be used when available. Observable inputs are inputs that market participants would use in pricing the asset or liability developed based on market data obtained from sources independent of the Company. Unobservable inputs are inputs that reflect the Company's assumptions of what market participants would use in pricing the asset or liability developed based on the

Bonanza Creek Energy, Inc.

Notes to the Consolidated Balance Sheet as of December 31, 2010

11. FAIR VALUE MEASUREMENTS: (Continued)

best information available in the circumstances. The hierarchy is broken down into three levels based on the reliability of the inputs as follows:

Level 1: Quoted prices are available in active markets for identical assets or liabilities;

Level 2: Quoted prices in active markets for similar assets and liabilities that are observable for the asset or liability; or

Level 3: Unobservable pricing inputs that are generally less observable from objective sources, such as discounted cash flow models or valuations.

ASC 820 requires financial assets and liabilities to be classified based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

The following table presents the Company's financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2010 by level within the fair value hierarchy:

	Fair Value Measurements Using		
	Level 1	Level 2	Level 3
Commodity derivative assets	$	$ 1,062,025	$ 2,379,629
Commodity derivative liabilities	$	$ 9,546,979	$

The Company's commodity swaps are valued using a market approach based on several factors, including observable transactions for the same or similar commodity options using the NYMEX futures index, and are designated as Level 2 within the valuation hierarchy. The Company's collars, which are designated as Level 3 within the valuation hierarchy, are also valued using a market approach, but are not validated by observable transactions with respect to volatility. The counterparty in all of the commodity derivative financial instruments is the lender on the Company's Senior Secured Revolving Credit facility (Note 6).

The allocation of the purchase price to the assets acquired and the liabilities assumed of BCEC and HEC was determined using Level 3 inputs. Compensation expense associated with the common stock class B shares was determined using Level 3 inputs.

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Bonanza Creek Energy, Inc.

Notes to the Consolidated Balance Sheet as of December 31, 2010

12. DERIVATIVES:

As of December 31, 2010, the Company's derivative commodity contracts with BNP Paribas are as follows:

Contract Term	Notional Volume	Floor	Ceiling	Fixed Price
January 1 - December 31, 2011	15,392 Bbl./Month	$ 90.00	$ 123.00	
January 1 - December 31, 2012	13,956 Bbl./Month	$ 90.00	$ 123.00	
January 1 - April 30, 2013	12,654 Bbl./Month	$ 90.00	$ 123.00	
January 1 - December 31, 2011	8,917 Bbl./Month			$ 64.45
January 1 - December 31, 2012	8,206 Bbl./Month			$ 62.95
January 1 - October 31, 2013	7,542 Bbl./Month			$ 61.50
January 1 - December 31, 2011	18,298 MMBTU/Month			$ 7.10
January 1 - December 31, 2012	16,860 MMBTU/Month			$ 6.75
January 1 - October 31, 2013	15,481 MMBTU/Month			$ 6.40

The table below contains a summary of all the Company's derivative positions reported on the consolidated balance sheet as of December 31, 2010:

Derivatives	Balance Sheet Location	Fair Value
Asset		
Commodity derivatives	Current derivative assets	$ 1,396,472
Commodity derivatives	Long-term derivative assets	2,045,182
Liability		
Commodity derivatives	Current derivative liability	(3,691,998)
Commodity derivatives	Long-term derivative liability	(5,854,980)
Total		$ (6,105,324)

13. SUBSEQUENT EVENTS:

During February of 2011, the Company received approximately $1 million as payment in full of the Company's note receivable from Patriot Resources, LLC the operator of the Sargent field in California.

During March of 2011, the Company entered into a new $300 million Senior Secured Revolving Credit Agreement with an initial borrowing base of $130 million with a syndicate of banks led by BNP Paribas.

On March 24, 2011, the Company entered into a new oil derivative commodity contract with Societe General with a floor price of $80.00 per Bbl with a ceiling price of $140.00 per Bbl covering 24,000 Bbl per month from April 1, 2011 through December 31, 2011.

Subsequent to December 31, 2010 the Company entered into new office operating leases in Bakersfield, California, and Denver, Colorado.

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Bonanza Creek Energy, Inc.

Notes to the Consolidated Balance Sheet as of December 31, 2010

14. DISCLOSURES ABOUT OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED):

The Company's oil and natural gas activities are entirely within the United States. Costs incurred in oil and natural gas producing activities are as follows:

	2010
Unproved property acquisition	$
Proved property acquisition	
Development	817,362
Exploration	
Total	$ 817,362

In December 2008, the SEC published the final rules and interpretations updating its oil and gas reporting requirements. The Company adopted the rules effective December 31, 2010, and the rule changes, including those related to pricing and technology, are included in the Company's reserve estimates.

In January 2010, the FASB aligned ASC Topic 932 with the aforementioned SEC requirements. Please refer to the section entitled "Adopted and Recently Issued Accounting Pronouncements" under Note 2 Summary of Significant Accounting Policies for additional discussion regarding both adoptions.

The estimate of proved reserves and related valuations for the year ended December 31, 2010 were based upon a report prepared by Cawley, Gillespie & Associates, Inc. Petroleum Consultants. The estimates of proved reserves are inherently imprecise and are continually subject to revision based on production history, results of additional exploration and development, price changes and other factors.

All of BCEI' oil and natural gas reserves are attributable to properties within the United States. A summary of BCEI's changes in quantities of proved oil and natural gas reserves for the year ended December 31, 2010 are as follows:

	Oil (MBbl)	Natural Gas (MMcf)
Balance December 23, 2010		
Extensions and discoveries		
Purchases of minerals in place	22,398	62,926
Production	(19)	(42)
Revisions to previous estimates		
Balance December 31, 2010	22,379	62,884
Proved developed reserves:		
December 23, 2010		
December 31, 2010	8,180	20,074
Proved undeveloped reserves:		
December 23, 2010		
December 31, 2010	14,199	42,810

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Bonanza Creek Energy, Inc.

Notes to the Consolidated Balance Sheet as of December 31, 2010

14. DISCLOSURES ABOUT OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED): (Continued)

The standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves were prepared in accordance with the provisions of ASC Topic 932. Future cash inflows were computed by applying prices to estimated future production. Future production and development costs are computed by estimating the expenditures to be incurred in developing and producing the proved oil and natural gas reserves at year-end, based on costs and assuming continuation of existing economic conditions.

Future income tax expenses are calculated by applying appropriate year-end tax rates to future pretax net cash flows relating to proved oil and natural gas reserves. Future income tax expenses give effect to permanent differences, tax credits and loss carryforwards relating to the proved oil and natural gas reserves. Future net cash flows are discounted at a rate of 10% annually to derive the standardized measure of discounted future net cash flows. This calculation procedure does not necessarily result in an estimate of the fair market value or the present value of BCEI's oil and natural gas properties.

The standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves are as follows (in thousands):

	December 31, 2010
Future cash flows	$ 1,894,178
Future production costs	(572,553)
Future development costs	(351,392)
Future income tax expense	(182,725)
Future net cash flows	787,508
10% annual discount for estimated timing of cash flows	(412,854)
Standardized measure of discounted future net cash flows	$ 374,654

Future cash flows as shown above were reported without consideration for the effects of derivative transactions outstanding at period end. The effect of hedging transactions in place as of year-end on the future cash flows for the period ended December 31, 2010 was immaterial.

The changes in the standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves are as follows (in thousands):

	2010
Beginning of period	$
Sale of oil and gas produced, net of production costs	(1,193)
Development costs incurred	817
Changes in estimated development cost	(817)
Purchases of mineral in place	374,768
Net change in income taxes	26
Accretion of discount	1,012
Changes in production rates and other	41
End of year	$ 374,654

Bonanza Creek Energy, Inc.

Notes to the Consolidated Balance Sheet as of December 31, 2010

14. DISCLOSURES ABOUT OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED): (Continued)

The average wellhead prices used in determining future net revenues related to the standardized measure calculation as of December 31, 2010 were calculated using the first-day-of-the-month price inclusive of adjustments for quality and location for each of the 12 months of calendar year 2010.

	2010
Oil (per Bbl)	$ 74.93
Gas (per Mcf)	$ 4.81

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BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(unaudited)

	March 31, 2011	December 31, 2010
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 768,048	$
Accounts receivable:		
Oil and gas sales	10,160,791	8,894,831
Other, net of $60,000 allowance	2,222,392	2,940,590
Prepaid expenses and other	1,052,061	703,063
Inventory of oilfield equipment	1,701,186	415,650
Derivative asset	500,547	1,396,472
Total current assets	16,405,025	14,350,606
OIL AND GAS PROPERTIES at cost, using the successful efforts method of accounting:		
Proved properties	446,663,305	441,303,069
Unproved properties	14,749,117	14,749,117
Wells in progress	16,281,855	8,387,164
	477,694,277	464,439,350
Less: accumulated depreciation, depletion and amortization	(6,445,660)	(470,390)
	471,248,617	463,968,960
NATURAL GAS PLANT at cost	36,847,855	31,840,475
Less: accumulated depreciation	(266,564)	(20,017)
	36,581,291	31,820,458
PROPERTY AND EQUIPMENT at cost	867,908	802,679
Less: accumulated depreciation	(45,294)	(10,008)
	822,614	792,671
LONG-TERM DERIVATIVE ASSET	500,931	2,045,182
OTHER ASSETS, net	2,923,798	3,125,670
TOTAL ASSETS	$ 528,482,276	$ 516,103,547

LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable and accrued expenses	$ 17,127,041	$ 16,101,536
Oil and gas revenue distribution payable	3,902,717	3,444,077
Derivative liability	5,756,860	3,691,998
Total current liabilities	26,786,618	23,237,611
LONG-TERM LIABILITIES:		
Bank revolving credit	63,500,000	55,400,000
Ad valorem taxes	374,656	1,213,445
Derivative liability	6,804,488	5,854,980
Deferred income taxes, net	68,597,393	68,405,393
Asset retirement obligations	5,711,792	5,611,709
TOTAL LIABILITIES	171,774,947	159,723,138
COMMITMENTS AND CONTINGENCIES (Note 4)		
STOCKHOLDERS' EQUITY:		
Common stock, Class A, $.001 par value, 99,990,000 shares authorized, 29,122,521 issued and outstanding	29,123	29,123
Common stock, Class B, $.001 par value, 10,000 shares authorized, 7,500 shares issued and outstanding		
Additional paid-in capital	356,513,012	356,513,012
Retained earnings accumulated (deficit)	165,194	(161,726)
Total stockholders' equity	356,707,329	356,380,409
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 528,482,276	$ 516,103,547

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BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES AND PREDECESSOR

CONSOLIDATED STATEMENTS OF OPERATIONS

(unaudited)

	Bonanza Creek Energy, Inc. Three Months Ended March 31, 2011	Bonanza Creek Energy Company, LLC (Predecessor) Three Months Ended March 31, 2010
NET REVENUES:		
Oil and gas sales	$ 22,212,617	$ 10,720,464
OPERATING EXPENSES:		
Lease operating	4,614,024	3,434,461
Severance and ad valorem taxes	1,052,919	332,732
Exploration	525,464	113,782
Depreciation, depletion and amortization	6,387,444	3,261,064
General and administrative	2,238,554	2,086,925
Total operating expenses	14,818,405	9,228,964
INCOME FROM OPERATIONS	7,394,212	1,491,500
OTHER INCOME (EXPENSE):		
Gain on sale of oil and gas properties		4,091,579
Other income (loss)	67,946	(59,542)
Change in fair value of warrant put option		(24,203,740)
Amortization of debt discount		(2,126,841)
Interest expense	(712,772)	(3,958,774)
Unrealized gain (loss) in fair value of derivatives	(5,454,546)	(1,142,426)
Realized gain (loss) in fair value of commodity derivatives	(775,920)	1,584,787
Total other income (expense)	(6,875,292)	(25,814,957)
INCOME (LOSS) BEFORE TAXES	518,920	(24,323,457)
Deferred income taxes	(192,000)	
NET INCOME (LOSS)	$ 326,920	$ (24,323,457)
BASIC AND DILUTED INCOME PER SHARE:	$ 0.01	
WEIGHTED AVERAGE NUMBER OF SHARES OF COMMON STOCK BASIC AND DILUTED	29,122,521	

See accompanying notes to these consolidated financial statements.

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BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY

(unaudited)

FOR THE QUARTER ENDED MARCH 31, 2011

	Common Stock A Shares		Common Stock B Shares		Additional Paid-In	Retained	
	Shares	Amount	Shares	Amount	Capital	Earnings	Total
BALANCES at January 1, 2011	29,122,521	$ 29,123	7,500	$	$ 356,513,012	$ (161,726)	$ 356,380,409
Net income						326,920	326,920
BALANCES at March 31, 2011	29,122,521	$ 29,123	7,500	$	$ 356,513,012	$ 165,194	$ 356,707,329

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BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES AND PREDECESSOR

CONSOLIDATED STATEMENTS OF CASH FLOWS

(unaudited)

	Bonanza Creek Energy, Inc. Three Months Ended March 31, 2011	Bonanza Creek Energy Company, LLC (Predecessor) Three Months Ended March 31, 2010
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	$ 326,920	$ (24,323,457)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	6,387,444	3,261,064
Deferred income taxes	192,000	
Exploration	(1,751)	
Amortization of deferred financing costs	201,782	281,640
Amortization of deferred novation fees		85,329
Accretion of debt discount		2,126,841
Payment in kind interest		2,682,829
Gain on sale of oil and gas properties		(4,091,579)
Valuation increase (decrease) in outstanding warrants		24,203,740
Valuation increase in commodity derivatives	5,454,546	1,142,426
Unrealized loss on derivative liability assumed		(1,311,868)
(Increase) decrease in operating assets:		
Accounts receivable	(547,762)	(613,391)
Prepaid expenses and other assets	(1,999,941)	138,472
(Decrease) increase in operating liabilities:		
Accounts payable and accrued liabilities	(1,445,852)	675,566
Settlement of asset retirement obligations	(32,200)	(33,003)
Net cash (used in) provided by operating activities	8,535,186	4,224,609
CASH FLOWS FROM INVESTING ACTIVITIES:		
Acquisition of oil and gas properties	(46,738)	4,260
Exploration and development of oil and gas properties	(10,402,241)	(1,500,872)
Gas plant capital expenditures	(5,353,380)	(316,990)
Proceeds from note receivable	986,906	35,224
Proceeds from sale of properties		7,506,300
Increase in receivable from Holmes Eastern Company, LLC		192,814
Additions to property and equipment non oil and gas	(65,229)	(223,423)
Net cash provided by (used in) investing activities	(14,880,322)	5,697,313
CASH FLOWS FROM FINANCING ACTIVITIES:		
Increase in bank revolving credit	71,900,000	
Payment on bank revolving credit and subordinated debt	(63,800,000)	(9,100,000)
Deferred financing costs	(986,816)	(53,379)
Net cash (used in) provided by financing activities	7,113,184	(9,153,379)

NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS		768,048		768,543
CASH AND CASH EQUIVALENTS:				
Beginning of period				2,521,513
End of period	$	768,048	$	3,290,056
SUPPLEMENTAL CASH FLOW DISCLOSURE:				
Cash paid for interest	$	609,196	$	994,305
Accrued interest on senior subordinated and related party notes			$	2,682,829
Changes in working capital related to drilling expenditures and property acquisition	$	2,209,959	$	13,926

See accompanying notes to these consolidated financial statements.

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Bonanza Creek Energy, Inc.

Notes to the Consolidated Financial Statements as of March 31, 2011 (unaudited)

1. ORGANIZATION AND BUSINESS:

On December 23, 2010, Bonanza Creek Energy, Inc. (a Delaware C corporation) (the Company or BCEI) was formed in conjunction with the following transactions which were accomplished simultaneously:

(1) The contribution by Bonanza Creek Energy Company, LLC (BCEC) of all of its ownership in Bonanza Creek Energy Operating Company, LLC (a wholly owned subsidiary) to BCEI and assumption by BCEI of BCEC's remaining debt (as described below) in exchange for a 21.55% ownership interest of BCEI. BCEC had no other significant assets or subsidiaries at such time. BCEC was an operating oil and gas company that was initially founded in 2006;

(2) The sale of $265 million of common stock of BCEI which constituted an ownership interest of 72.68% of BCEI to two private equity firms: 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); and

(3) The exchange of shares of 5.77% of BCEI's common stock together with $59 million in cash (which came from the $265 million sale of common stock of BCEI described in (2) above), for all of the equity interests of Holmes Eastern Company, LLC (HEC), a limited liability company that was majority owned by a minority member of Bonanza Creek Oil Company, LLC (BCOC). BCOC was the predecessor of BCEC and owned 29.9% of BCEC on a fully diluted basis at the time of such transaction. HEC was initially formed in 2009 and has been an operating oil and gas exploration and production business since its formation.

Ultimately, the BCEC ownership (21.55%) of BCEI will be distributed to BCEC's members based on management's estimate of fair value of the BCEI shares received by BCEC to holders of the equity interests of BCEC in connection with the redemption of BCEC's equity and BCEC's dissolution to:

(1) BCOC in the amount of 5.5% (for its Series A Units of BCEC);

(2) D.E. Shaw Laminar Portfolios, L.L.C. (Laminar) in the amount of 12.91% (for its Series A Units of BCEC); and

(3) The management of BCEC, in the amount of 3.14% (for their Series B Units of BCEC).

Cash proceeds of approximately $182 million were used to retire BCEC's second lien term loan, senior subordinated notes and a related party note payable, and to reduce the outstanding principal balance on BCEC's outstanding bank revolving credit facility by $29 million thereby reducing the balance outstanding to approximately $55.4 million as of December 31, 2010. This loan at the same time was assumed by BCEI.

The Company is engaged primarily in acquiring, developing, exploiting and producing oil and gas properties. As of March 31, 2011, the Company's assets and operations are concentrated primarily in southern Arkansas and in the Denver-Julesburg and North Park Basins in the Rocky Mountains.

2. RECENT ACCOUNTING PRONOUNCEMENTS:

The Company follows the provisions of FASB ASC 740, *Accounting for Uncertainty in Income Taxes*. The statement does not have a material effect on the Company's financial position. The Company recognizes interest and penalties related to uncertain tax positions in income tax expense. The Company files income tax returns in the U.S. federal jurisdiction and various states. The tax return for December 31, 2010 has not yet been filed and the Company has not taken any uncertain tax positions.

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Bonanza Creek Energy, Inc.

Notes to the Consolidated Financial Statements as of March 31, 2011 (unaudited)

2. RECENT ACCOUNTING PRONOUNCEMENTS: (Continued)

In December 2010, the FASB issued Accounting Standards Update No. 2010-29, *Business Combinations: Disclosure of Supplementary Pro Forma Information for Business Combinations* (ASU 2010-29), which provides amendments to FASB ASC Topic 805, *Business Combinations*. The objective of ASU 2010-29 is to clarify and expand the pro forma revenue and earnings disclosure requirements for business combinations. ASU 2010-29 is effective for fiscal years beginning after December 15, 2010. The adoption of this standard will not have an impact on the Company's consolidated financial statements other than additional disclosures.

3. SENIOR SECURED REVOLVING CREDIT FACILITY:

Senior Secured Revolving Credit Facility On March 29, 2011, the Company entered into a Senior Secured Revolving Credit Agreement (the "Revolver") with a syndication of banks, with BNP Paribas as the administrative agent and issuing lender, which provides for borrowings of up to $300 million. The Revolver provides for interest rates plus an applicable margin to be determined based on the London Interbank Offered Rate (LIBOR) or a bank base rate ("Base Rate"), at the Company's election. LIBOR borrowings bear interest at LIBOR plus 2.00% to 3.00% depending on the utilization level, and the Base Rate borrowings bear interest at the "Bank Prime Rate," as defined plus 1.00% to 2.00%.

The Revolver has a $130 million borrowing base as of March 31, 2011 and is subject to semi-annual re-determinations in April and October of each year. The Revolver provides for commitment fees of 0.5% and restricts, among other items, the payment of dividends, certain additional indebtedness, sale of assets, loans, certain investments and mergers. The Revolver also contains certain financial covenants, which require the maintenance of a minimum current ratio and a minimum debt coverage ratio, as defined. The Company was in compliance with these covenants as of March 31, 2011. The Revolver is collateralized by substantially all the Company's assets and matures on March 29, 2015.

In association with the Revolver agreement, the Company incurred deferred financing costs of approximately $987,000.

4. COMMITMENTS AND CONTINGENT LIABILITIES:

Office Leases The Company rents office facilities under various noncancelable operating lease agreements. Rental expense for these leases was $138,561 for the three months ended March 31, 2011. The Company's noncancelable operating lease agreements result in total future minimum noncancelable lease payments which are presented below:

	Office Leases	Line of Credit	Total
2011	$ 301,594	$	$ 301,594
2012	436,550		436,550
2013	444,733		444,733
2014	455,678		455,678
2014	468,594	63,500,000	63,968,594
2016 and thereafter	200,832		200,832
	$ 2,307,981	$ 63,500,000	$ 65,807,981

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Bonanza Creek Energy, Inc.

Notes to the Consolidated Financial Statements as of March 31, 2011 (unaudited)

4. COMMITMENTS AND CONTINGENT LIABILITIES: (Continued)

Environmental The Company is engaged in oil and gas exploration and production and may become subject to certain liabilities as they relate to environmental cleanup of well sites or other environmental restoration procedures as they relate to the drilling of oil and gas wells and the operations. In the Company's acquisition of existing or previously drilled well bores, the Company may not be aware of what environmental safeguards were taken at the time such wells were drilled or during such time the wells were operated. Should it be determined that a liability exists with respect to any environmental clean up or restoration, the liability to cure such a violation could fall upon the Company. Management believes its properties are operated in conformity with local, state and federal regulations. No claim has been made, nor is the Company aware of any uninsured liability which the Company may have, as it relates to any environmental cleanup, restoration or the violation of any rules or regulations.

Legal Proceeding The Company may, from time to time, be involved in various other legal actions arising in the normal course of business. In the opinion of management, the Company's liability, if any, in these pending actions would not have a material adverse effect on the financial positions of the Company. The Company's general and administrative expenses would include amounts incurred to resolve claims made against the Company.

5. FAIR VALUE MEASUREMENTS AND ASSET RETIREMENT OBLIGATION:

The Company follows FASB ASC 820, *Fair Value Measurements and Disclosures*, which defines fair value, establishes a framework for using fair value to measure assets and liabilities, and expands disclosures about fair value measurements. The statement establishes a hierarchy for inputs used in measuring fair value that maximizes the use of observable inputs and minimizes the use of unobservable inputs by requiring that the most observable inputs be used when available. Observable inputs are inputs that market participants would use in pricing the asset or liability developed based on market data obtained from sources independent of the Company. Unobservable inputs are inputs that reflect the Company's assumptions of what market participants would use in pricing the asset or liability developed based on the best information available in the circumstances. The hierarchy is broken down into three levels based on the reliability of the inputs as follows:

Level 1: Quoted prices are available in active markets for identical assets or liabilities;

Level 2: Quoted prices in active markets for similar assets and liabilities that are observable for the asset or liability; or

Level 3: Unobservable pricing inputs that are generally less observable from objective sources, such as discounted cash flow models or valuations.

ASC 820 requires financial assets and liabilities to be classified based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

Bonanza Creek Energy, Inc.

Notes to the Consolidated Financial Statements as of March 31, 2011 (unaudited)

5. FAIR VALUE MEASUREMENTS AND ASSET RETIREMENT OBLIGATION: (Continued)

The following table presents the Company's financial assets and liabilities that were accounted for at fair value on a recurring basis as of March 31, 2011 by level within the fair value hierarchy:

	Fair Value Measurements Using		
	Level 1	Level 2	Level 3
Commodity derivative assets	$	$ 915,735	$ 85,743
Commodity derivative liabilities	$	$ 12,201,477	$ 359,870

The following table presents the Company's financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2010 by level within the fair value hierarchy:

	Fair Value Measurements Using		
	Level 1	Level 2	Level 3
Commodity derivative assets	$	$ 1,062,025	$ 2,379,629
Commodity derivative liabilities	$	$ 9,546,979	$

The Company's commodity swaps are valued based on the counterparty's mark-to-market statements, which are validated by observable transactions for the same or similar commodity options using the NYMEX futures index, and are designated as Level 2 within the valuation hierarchy. The Company's collars, which are designated as Level 3 within the valuation hierarchy, are also valued based on the counterparty's mark-to-market statements, but are not validated by observable transactions with respect to volatility. The counterparties in all of the commodity derivative financial instruments are lenders on the Company's senior secured revolving credit facility.

The following table reflects the activity for the commodity derivatives measured at fair value using Level 3 inputs:

	For the Three Months Ended March 31, 2010
Beginning net asset (liability) balance	$ 2,379,629
Net decrease in fair value	(2,643,320)
Net realized gain on settlement	(10,436)
Transfers in (out) of Level 3	
Ending net asset (liability) balance	$ (274,127)

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Bonanza Creek Energy, Inc.

Notes to the Consolidated Financial Statements as of March 31, 2011 (unaudited)

5. FAIR VALUE MEASUREMENTS AND ASSET RETIREMENT OBLIGATION: (Continued)

As of March 31, 2011, the Company's derivative commodity contracts with BNP Paribas and Societe Generale are as follows:

Contract Term	Notional Volume	Floor	Ceiling	Fixed Price
April 1 - December 31, 2011	24,400 Bbl./Month	$ 80.00	$ 140.00	
April 1 - December 31, 2011	15,392 Bbl./Month	$ 90.00	$ 123.00	
January 1 - December 31, 2012	13,956 Bbl./Month	$ 90.00	$ 123.00	
January 1 - April 30, 2013	12,654 Bbl./Month	$ 90.00	$ 123.00	
April 1 - December 31, 2011	9,964 Bbl./Month			$ 64.45
April 1 - December 31, 2011	1,604 Bbl./Month			$ 63.87
January 1 - December 31, 2012	8,206 Bbl./Month			$ 62.95
January 1 - December 31, 2012	1,520 Bbl./Month			$ 63.47
January 1 - October 31, 2013	7,542 Bbl./Month			$ 61.50
April 1 - December 31, 2011	18,298 MMBTU/Month			$ 7.10
January 1 - December 31, 2012	16,860 MMBTU/Month			$ 6.75
January 1 - October 31, 2013	15,481 MMBTU/Month			$ 6.40

The table below contains a summary of all the Company's derivative positions reported on the consolidated balance sheet as of March 31, 2011:

Derivatives	Balance Sheet Location	Fair Value
Asset		
Commodity derivatives	Current derivative assets	$ 500,547
Commodity derivatives	Long-term derivative assets	500,931
Liability		
Commodity derivatives	Current derivative liability	(5,756,860)
Commodity derivatives	Long-term derivative liability	(6,804,488)
Total		$ (11,559,870)

Realized gains and losses on commodity derivatives and the unrealized gains or losses are recorded in other income (expense).

6. SUBSEQUENT EVENTS:

Subsequent events have been evaluated by management through the date of issuance of these financial statements.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Managers
Bonanza Creek Energy Company, LLC

We have audited the consolidated balance sheets of Bonanza Creek Energy Company, LLC and subsidiaries as of December 23, 2010 and December 31, 2009 and the related consolidated statements of operations, members' equity, and cash flows for the period January 1, 2010 to December 23, 2010 and the years ended December 31, 2009 and 2008. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of Bonanza Creek Energy Company, LLC and its subsidiaries as of December 23, 2010 and December 31, 2009 and the results of their operations and their cash flows for the period from January 1, 2010 to December 23, 2010 and for the years ending December 31, 2009 and 2008 in conformity with U.S. generally accepted accounting principles.

/s/ Hein & Associates LLP

Denver, Colorado
July 21, 2011

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BONANZA CREEK ENERGY COMPANY, LLC AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 23, 2010	December 31, 2009
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 2,450,191	$ 2,521,513
Accounts receivable:		
Oil and gas sales, net of $0 and $273,048 allowance	5,212,542	4,599,281
Holmes Eastern Company, LLC	3,665,703	
Other, net of $60,000 allowance	670,456	557,560
Prepaid expenses and other	755,751	783,109
Inventory of oilfield equipment	415,650	709,364
Derivative asset	1,465,545	2,445,386
Total current assets	14,635,838	11,616,213
OIL AND GAS PROPERTIES at cost, using the successful efforts method of accounting:		
Proved properties	227,508,385	198,962,097
Unproved properties	2,647,655	1,896,268
Wells in progress	5,785,954	1,333,810
	235,941,994	202,192,175
Less: accumulated depreciation, depletion and amortization	(51,635,257)	(40,658,624)
	184,306,737	161,533,551
NATURAL GAS PLANT at cost	33,387,027	29,392,723
Less: accumulated depreciation	(5,304,814)	(3,336,359)
	28,082,213	26,056,364
PROPERTY AND EQUIPMENT at cost	2,192,642	1,777,377
Less: accumulated depreciation	(1,398,846)	(1,000,135)
	793,796	777,242
LONG-TERM DERIVATIVE ASSET	2,216,087	4,899,191
OTHER ASSETS, net	6,010,519	6,669,541
TOTAL ASSETS	$ 236,045,190	$ 211,552,102
LIABILITIES AND MEMBERS' DEFICIT		
CURRENT LIABILITIES:		
Accounts payable and accrued expenses	$ 14,614,980	$ 5,434,419

Oil and gas revenue distribution payable	1,808,136	1,612,965
Derivative liability	3,598,869	
Bank revolving credit current portion		2,700,000
Total current liabilities	20,021,985	9,747,384
LONG-TERM LIABILITIES:		
Bank revolving credit	84,400,000	99,000,000
Senior subordinated notes (net of discount of $14,327,348 and $23,189,303)	110,817,857	92,441,757
Second lien term loan	30,000,000	
Note payable related party	12,276,228	10,798,846
Ad valorem taxes	964,594	1,078,667
Derivative liability	5,286,378	9,754,968
Asset retirement obligations	4,966,366	1,857,486
Warrants	47,123,364	81,468,258
TOTAL LIABILITIES	315,856,772	306,147,366
COMMITMENTS AND CONTINGENCIES (Notes 1, 7 and 8)		
MEMBERS' DEFICIT:		
Class A units, $1.00 par value, 29,775 units authorized, 14,090 issued, liquidation preference of $10,450,163	8,504,941	8,504,941
Class B units, $1.00 par value, 7,452 units authorized, 4,844 issued		
Class A warrants, 33,089 units under warrants, respectively		
Accumulated deficit	(88,316,523)	(103,100,205)
Total members' deficit	(79,811,582)	(94,595,264)
TOTAL LIABILITIES AND MEMBERS' DEFICIT	$ 236,045,190	$ 211,552,102

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BONANZA CREEK ENERGY COMPANY, LLC AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	For the Period January 1, 2010 to December 23, 2010	For the Years Ended December 31, 2009	2008
NET REVENUES:			
Oil and gas sales	$ 48,328,094	$ 34,441,453	$ 47,914,801
OPERATING EXPENSES:			
Lease operating	14,791,785	13,449,246	20,434,655
Severance and ad valorem taxes	1,620,495	2,147,723	1,846,984
Exploration	360,742	131,059	25,278
Depreciation, depletion and amortization	14,225,309	14,107,774	25,463,113
Impairment of oil and gas properties		579,337	26,437,380
General and administrative	8,374,875	7,610,252	7,476,776
Cancelled private placement	2,378,468		
Total operating expenses	41,751,674	38,025,391	81,684,186
INCOME (LOSS) FROM OPERATIONS	6,576,420	(3,583,938)	(33,769,385)
OTHER INCOME (EXPENSE):			
Gain on sale of oil and gas properties	4,055,153	303,085	7,715
Write off of deferred financing costs	(1,663,167)		
Change in fair value of warrant put option	34,344,894	(80,639,866)	70,972,241
Accretion of debt discount	(8,861,955)	(7,963,031)	(5,986,491)
Realized gain (loss) on settled commodity derivatives	5,918,702	13,450,810	1,912,725
Interest expense	(18,000,796)	(16,581,566)	(12,870,332)
Unrealized gain (loss) in fair value of commodity derivatives	(7,604,742)	(34,589,118)	48,716,636
Other income (loss)	19,173	(179,840)	(229,366)
Total other income (expense)	8,207,262	(126,199,526)	102,523,128
NET INCOME (LOSS)	$ 14,783,682	$ (129,783,464)	$ 68,753,743
UNAUDITED PRO FORMA INCOME TAXES:			
Net income (loss) as presented	$ 14,783,682	$ (129,783,464)	$ 68,753,743
Pro Forma income taxes			
Pro Forma, net income (loss) as adjusted	$ 14,783,682	$ (129,783,464)	$ 68,753,743

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BONANZA CREEK ENERGY COMPANY, LLC AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF MEMBERS' DEFICIT

FOR THE PERIOD ENDED DECEMBER 23, 2010,

AND FOR THE YEARS ENDED DECEMBER 31, 2009 AND 2008

	Common Stock		Class A Units Under Warrants		Class B Units		Accumulated	
	Shares	Amount	Units	Amount	Units	Amount	Deficit	Total
BALANCES at January 1, 2008	14,090	$ 8,504,941	19,672	$	4,844	$	$ (42,070,484)	$ (33,565,543)
Issuance of units			13,417					
Net income							68,753,743	68,753,743
BALANCES at December 31, 2008	14,090	8,504,941	33,089		4,844		26,683,259	35,188,200
Issuance of units								
Net income							(129,783,464)	(129,783,464)
BALANCES at December 31, 2009	14,090	8,504,941	33,089		4,844		(103,100,205)	(94,595,264)
Net income							14,783,682	14,783,682
BALANCES at December 23, 2010	14,090	$ 8,504,941	33,089	$	4,844	$	$ (88,316,523)	$ (79,811,582)

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BONANZA CREEK ENERGY COMPANY, LLC AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the Period January 1, 2010 to December 23, 2010	For the Years Ended December 31, 2009	2008
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ 14,783,682	$ (129,783,464)	$ 68,753,743
Adjustments to reconcile net income (loss) to net cash provided by operating activities			
Depreciation, depletion and amortization	14,225,309	14,107,774	25,463,113
Change in unrealized loss on derivative liability assumed	(4,811,518)	(5,779,144)	(5,624,682)
Exploration	42,758		
Impairment of oil and gas properties		579,337	26,437,380
Amortization of deferred financing costs	1,641,209	1,643,883	1,094,962
Write off of deferred financing costs	1,663,167		
Amortization of deferred novation fees	403,676	341,314	220,186
Accretion of debt discount	8,861,955	7,963,031	5,986,491
Payment in kind interest	10,991,527	9,778,365	6,401,568
Gain on sale of oil and gas properties	(4,055,153)	(303,085)	(7,715)
Provision for losses on accounts receivable			342,258
Valuation increase (decrease) in outstanding warrants	(34,344,894)	80,639,866	(70,972,241)
Valuation increase in commodity derivatives	7,604,742	34,589,118	(48,716,636)
Other		137,712	
(Increase) decrease in operating assets:			
Accounts receivable	(726,157)	(100,356)	(3,662,512)
Prepaid expenses and other assets	27,358	544,913	(189,064)
(Decrease) increase in operating liabilities:			
Accounts payable and accrued liabilities	6,495,772	(3,183,544)	5,613,557
Settlement of asset retirement obligations	(44,758)	(41,664)	(12,495)
Net cash provided by operating activities	22,758,675	11,134,056	11,127,913
CASH FLOWS FROM INVESTING ACTIVITIES:			
Acquisition of oil and gas properties	(1,066,277)	(650,306)	(40,845,931)
Exploration and development of oil and gas properties	(34,727,567)	(6,611,956)	(38,384,063)
Proceeds from note receivable	103,903	238,544	
Proceeds from sale of properties	7,475,654	307,257	142,533
Decrease in restricted cash	250,000		
Increase in receivable from Holmes Eastern Company, LLC	(3,665,703)		
Additions to property and equipment non oil and gas	(497,073)	(468,588)	(493,977)
Net cash used in investing activities	(32,127,063)	(7,185,049)	(79,581,438)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Increase in bank revolving credit and subordinated debt	118,200,000	3,000,000	72,125,699
Payment on bank revolving credit and subordinated debt	(105,500,000)	(8,300,000)	(4,000,000)
Increase in note payable			10,000,000
Deferred financing costs	(3,075,534)	(215,439)	(3,743,644)
Deferred novation fees	(327,400)		(1,840,585)
Net cash (used in) provided by financing activities	9,297,066	(5,515,439)	72,541,470
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(71,322)	(1,566,432)	4,087,945
CASH AND CASH EQUIVALENTS:			

Beginning of period		2,521,513		4,087,945		
End of period	$	2,450,191	$	2,521,513	$	4,087,945
SUPPLEMENTAL CASH FLOW DISCLOSURE:						
Cash paid for interest	$	5,410,127	$	5,159,318	$	5,373,801
Assumption of bank debt related to acquisition of oil and gas properties	$		$		$	52,100,000
Assumption of hedge liability related to acquisition of oil and gas properties	$		$		$	27,372,262
Fair value of warrants issued for debt	$		$		$	28,949,888
Changes in working capital related to drilling expenditures and property acquisition	$	2,723,130	$	(70,292)	$	(1,996,326)

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Bonanza Creek Energy Company, LLC

Notes to the Consolidated Financial Statements as of December 23, 2010

1. ORGANIZATION AND BUSINESS:

Bonanza Creek Energy Company, LLC (a Delaware limited liability company) (BCEC) and subsidiaries (collectively "Bonanza Creek" or the "Company") was formed on May 17, 2006 for the purpose of consolidating certain oil and natural gas assets of Bonanza Creek Oil Company, LLC ("BCOC") and to sell senior subordinated unsecured notes in the amount of $27 million to Laminar Direct Capital VI, L.L.C. ("Laminar"). In connection with the transaction, BCOC contributed certain oil and natural gas assets and liabilities to BCEC in exchange for 13,250 Class A membership units in the Company. Since the contribution was among related parties, the assets and liabilities were recorded at their book values. Simultaneous with the contribution of assets and liabilities, Bonanza Creek sold $27 million in notes to Laminar (see Notes 7 and 9).

Bonanza Creek is engaged primarily in acquiring, developing, exploiting and producing oil and gas properties. As of December 23, 2010, the Company's assets and operations are concentrated primarily in southern Arkansas and in the DJ and North Park Basins in the Rocky Mountains.

On December 23, 2010 Bonanza Creek Energy Inc. (a Delaware C corporation) (BCEI) was formed in connection with the sale of $265 million of common stock which constituted an ownership interest of 72.68% to Project Black Bear LP, an entity advised by West Face Capital Inc. ("West Face Capital") and to certain clients of AIMCo. In connection with this transaction, BCEC contributed all of its ownership in Bonanza Creek Energy Operating Company, LLC (a wholly owned subsidiary) for a 21.55% ownership interest in BCEI's common stock. The remaining 5.77% of BCEI's common stock, along with $59 million in cash, was exchanged for all of the ownership of Holmes Eastern Company, LLC (HEC) a single member LLC that was majority owned by a member of BCOC and parties and members of BCEC's management. Upon completion of the sale of common stock and the acquisition of HEC, BCEC's ownership was approved by the Board of Directors to be liquidated by distribution of all of its BCEI common stock (21.55%) to BCOC in the amount of 5.5%, Laminar in the amount of 12.91%, and management in the amount of 3.14%. Subsequent to the sale to BCEI cash proceeds of approximately $182 million were used to retire the second lien debt, the senior subordinated notes, the related party note payable, and made a $29 million principal payment on its bank revolving credit facility which reduced the balance outstanding to approximately $55.4 million.

Subsequent to the transaction with BCEI, BCEC incurred the following expenses in connection with repayment of debt:

Write off of deferred financing costs	$	(2,869,080)
Subordinated note payoff penalty	$	(14,327,348)
Second lien loan term loan payoff penalty	$	(3,031,667)

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

Principles of Consolidation The consolidated financial statements include the accounts of BCEC and its wholly owned subsidiaries, Bonanza Creek Energy Operating Company and Bonanza Creek Energy Resources Company. All significant intercompany accounts and transactions have been eliminated.

Fair Value of Financial Instruments Bonanza Creek's financial instruments consist of cash, trade receivables, trade payables, accrued liabilities, long-term debt and derivative instruments. The carrying

Bonanza Creek Energy Company, LLC

Notes to the Consolidated Financial Statements as of December 23, 2010

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES: (CONTINUED)

value of cash and cash equivalents, trade receivables and trade payables are considered to be representative of their fair market value, due to the short maturity of these instruments. Long-term debt is based on variable rate interest and, accordingly, approximates fair value. The fair value of derivative contracts are estimated based on market conditions in effect at the end of each reporting period.

Use of Estimates The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of oil and gas reserves, assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting period. Actual results could differ from those estimates.

Cash and Cash Equivalents Bonanza Creek considers all highly liquid investments with original maturity dates of three months or less to be cash equivalents.

Accounts Receivable Trade accounts receivable are recorded at net realizable value. If the financial condition of the Company's customers were to deteriorate, resulting in an impairment of their ability to make payments, additional allowances may be required. Delinquent trade accounts receivable are charged against the allowance for doubtful accounts once uncollectibility has been determined.

The Company's crude oil and natural gas receivables are generally collected within two months. The Company accrues a reserve on a receivable when, based on the judgment of management, it is probable that a receivable will not be collected and the amount of any reserve may be reasonably estimated.

Inventory of Oilfield Equipment Inventory consists of material and supplies used in connection with the Company's drilling program. These inventories are stated at the lower of average cost or market.

Oil and Gas Producing Activities Bonanza Creek follows the successful efforts method of accounting for its oil and gas properties. Under this method of accounting, all property acquisition costs and costs of exploratory and development wells are capitalized when incurred, pending determination of whether the well has found proved reserves. If an exploratory well has not found proved reserves, the costs of drilling the well and other associated costs are charged to expense. During 2010, 2009 and 2008, the Company recorded charges to exploration expense in the amount of $0, $0, and $0, respectively, for exploratory wells that did not find proved reserves. The costs of development wells are capitalized whether productive or nonproductive. Interest cost is capitalized as a component of property cost for capital development projects exceeding $1,000,000 that require greater than six months to be readied for their intended use. For the period ended December 23, 2010, and for the years ended December 31, 2009, and 2008, the Company did not capitalize any interest expense. Costs incurred to maintain wells and related equipment and lease and well operating costs are charged to expense as incurred. Gains and losses arising from sales of properties are included in income. However, sales that do not significantly affect a field's unit-of-production depletion rate are accounted for as normal retirements with no gain or loss recognized. Geological and geophysical costs of exploratory prospects and the costs of carrying and retaining unproved properties are expensed as incurred.

Depletion, depreciation and amortization (DD&A) of capitalized costs of proved oil and gas properties are provided for on a field-by-field basis using the units of production method based upon proved reserves. The computation of DD&A takes into consideration the anticipated proceeds from equipment salvage and Bonanza's expected cost to abandon its well interests. DD&A expense for oil and

Bonanza Creek Energy Company, LLC

Notes to the Consolidated Financial Statements as of December 23, 2010

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES: (CONTINUED)

gas producing property and related equipment was $11,826,605, $11,792,914, and $23,710,388 for the period ended December 23, 2010, and for the years ended December 31, 2009 and 2008, respectively.

The Company assesses its proved oil and gas properties for impairment whenever events or circumstances indicate that the carrying value of the assets may not be recoverable. The impairment test compares undiscounted future net cash flows to the assets' net book value. If the net capitalized costs exceed future net cash flows, then the cost of the property is written down to "fair value." Fair value for oil and natural gas properties is generally determined based on discounted future net cash flows.

For the period ended December 23, 2010, for the years ended December 31, 2009, and 2008, the Company recorded impairment expenses of $0, $0.6 million, and $26.4 million, respectively, related to proved property impairment write-downs. These calculations involved significant unobservable inputs and, therefore, they are Level 3 fair value estimates.

The Company records the fair value of a liability for an asset retirement obligation as an asset and a liability when there is a legal obligation associated with the retirement of a long-lived asset and the amount can be reasonably estimated. Refer also to Note 8 relating to asset retirement obligations, which includes additional information on the Company's asset retirement obligations.

Long-Lived Assets Long-lived assets to be held and used or disposed of other than by sale are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. When required, impairment losses on assets to be held and used or disposed of other than by sale are recognized based on the fair value of the asset. Long-lived assets to be disposed of by sale are reported at the lower of their carrying amount or fair value less cost to sell.

Other Property and Equipment Property and equipment are recorded at cost. Depreciation is calculated using the straight-line method over the estimated useful lives of the assets, which range from three to ten years.

Revenue Recognition The Company records revenues from the sales of crude oil and natural gas when delivery to the customer has occurred and title has transferred, net of royalties, discounts and allowances, as applicable. This occurs when oil or gas has been delivered to a pipeline or a tank lifting has occurred. The Company has interests with other producers in certain properties in which case the Company uses the entitlement method to account for gas imbalances. There were no gas imbalances in any period presented.

For gathering and processing services, the Company either receives fees or commodities from natural gas producers depending on the type of contract. Under the percentage-of-proceeds contract type, the Company is paid for its services by keeping a percentage of the natural gas liquids (NGL) produced and a percentage of the residue gas resulting from processing the natural gas. Commodities received are, in turn, sold and recognized as revenue in accordance with the criteria outline above.

Income Taxes Bonanza Creek is a limited liability company. Accordingly, no provision for income tax has been recorded as the income, deductions, expenses and credits of the Company are reported on the individual income tax returns of the Company's members.

For financial reporting purposes, the Company has included pro-forma income taxes and pro-forma net income (loss) as if it had been a tax reporting entity. No pro-forma taxes were presented primarily due to the permanent differences between financial reporting and tax reporting on this change to fair value of

Bonanza Creek Energy Company, LLC

Notes to the Consolidated Financial Statements as of December 23, 2010

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES: (CONTINUED)

the warrant put option. The change in the fair value of the warrant put option is a permanent difference between financial reporting and tax reporting in the amount of $34.3 million, $(80.6) million, and $71.0 million for the period ended December 23, 2010 and years ended December 31, 2009 and 2008, respectively. During these periods there was a net financial reporting loss after removal of the change in the fair value of the warrant put option. During these same periods, the taxable loss exceeds the adjusted financial reporting loss due to the deduction of intangible costs.

Concentrations of Credit Risk The Company maintains cash and cash equivalents at various financial institutions. At various times throughout the period ended December 23, 2010 and the year ended December 31, 2009, the Company's cash balances exceeded the Federal Deposit Insurance Corporation (FDIC) insured limit of $250,000.

During 2010, Lion Oil Trading & Transport and Plains Marketing accounted for 52% and 30%, respectively, of oil and natural gas sales. During 2009, Lion Oil Trading & Transport, Plains Marketing and Hathaway LLC accounted for 46%, 27% and 12%, respectively, of oil and gas sales. During 2008, Lion Oil Trading & Transport, Teppco Crude Oil, Independent Oil Producers and Plains Marketing accounted for 28%, 16%, 15% and 11%, respectively, of oil and gas sales.

Risks and Uncertainties Historically, oil and gas prices have experienced significant fluctuations and have been particularly volatile in recent years. Price fluctuations can result from variations in weather, levels of regional or national production and demand, availability of transportation capacity to other regions of the country, and various other factors. Increases or decreases in prices received could have a significant impact on future results.

Oil and Gas Derivative Activities The Company recognizes all derivative instruments on the balance sheet as either assets or liabilities at fair value. Changes in the derivative's fair value will be recognized in the statement of operations.

The Company is exposed to commodity price risk related to oil and gas prices. To mitigate this risk, the Company enters into oil and gas forward contracts as hedges. The Company maintained oil and gas contracts that economically hedged approximately 46%, 52% and 29%, respectively, of oil and gas sales during 2010, 2009 and 2008. The contracts, which are generally placed with major financial institutions or with counter parties which management believes to be of high credit quality, may take the form of futures contracts, swaps or options. The oil and gas reference prices of these contracts are based upon oil and natural gas futures, which have a high degree of historical correlation with actual prices received by the Company. The Company had realized gains on these oil contracts, reflected in other income, of $5,918,702, $13,450,810 and $1,912,725 for 2010, 2009 and 2008, respectively.

Prior Period Reclassifications Certain reclassifications have also been made to the prior year consolidated financial statements to conform to the current year presentation. Such reclassifications had no effect on net income (loss).

Adopted and Recently Issued Accounting Pronouncements The Company adopted the provisions of FASB ASC 740, *Accounting for Uncertainty in Income Taxes*, on January 1, 2009. The adoption of this statement did not have a material effect on the Company's financial position, results of operations or cash flows. The Company has not recorded any liabilities as of December 23, 2010 and December 31, 2009 related to the adoption of this statement. Subsequent to adoption, there have been no changes to the Company's assessment of uncertain tax positions. The Company recognizes interest and penalties related

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Bonanza Creek Energy Company, LLC

Notes to the Consolidated Financial Statements as of December 23, 2010

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES: (CONTINUED)

to uncertain tax positions in income tax expense. As of December 23, 2010 and December 31, 2009, the Company made no provision for interest or penalties related to uncertain tax positions. The Company files income tax returns in the U.S. federal jurisdiction and various states. There are currently no federal or state income tax examinations underway for these jurisdictions. Furthermore, the Company is no longer subject to U.S. federal income tax examinations by the Internal Revenue Service for tax years before 2006 and for state and local tax authorities for years before 2006. The Company's tax years of 2006 and forward are subject to examination by federal and state taxing authorities.

In December 2010, the FASB issued Accounting Standards Update No. 2010-29, *Business Combinations: Disclosure of Supplementary Pro Forma Information for Business Combinations* (ASU 2010-29), which provides amendments to FASB ASC Topic 805, *Business Combinations*. The objective of ASU 2010-29 is to clarify and expand the pro forma revenue and earnings disclosure requirements for business combinations. ASU 2010-29 is effective for fiscal years beginning after December 15, 2010. The adoption of this standard will not have an impact on the Company's consolidated financial statements other than additional disclosures.

In January 2010, the FASB issued Accounting Standards Update No. 2010-06, *Improving Disclosures about Fair Value Measurements* (ASU 2010-06), which provides amendments to FASB ASC Topic 820, *Fair Value Measurements and Disclosures.* The objective of ASU 2010-06 is to provide more robust disclosures about (i) the different classes of assets and liabilities measured at fair value, (ii) the valuation techniques and inputs used, (iii) the activity in Level 3 fair value measurements, and (iv) significant transfers between Levels 1, 2 and 3. ASU 2010-06 was effective for fiscal years and interim periods beginning after December 15, 2009, except for the activity in Level 3 measurement disclosures which was effective January 1, 2011. The Company adopted ASU 2010-06 effective January 1, 2010, which did not have an impact on its consolidated financial statements, other than additional disclosures.

In December 2008, the SEC issued *Modernization of Oil and Gas Reporting: Final Rule,* which published the final rules and interpretations updating its oil and gas reporting requirements. The final rule includes updates to definitions in the existing oil and gas rules to make them consistent with the petroleum resource management system, which is a widely accepted standard for the management of petroleum resources that was developed by several industry organizations. Key revisions include the ability to include nontraditional resources in reserves, the use of new technology for determining reserves, permitting disclosure of probable and possible reserves, and changes to the pricing used to determine reserves in that companies must use a 12-month average price. The average is calculated using the first-day-of-the-month price for each of the 12 months that make up the reporting period. The Company adopted the new rules effective December 31, 2009, and as a result, the Company (i) prepared its reserve estimates as of December 31, 2009 and 2010 based on the new reserve definitions, (ii) has estimated its December 31, 2009 and 2010 reserve quantities using the 12-month average price and (iii) included additional disclosures as required by the new rule. Oil and gas reserve quantities or their values are a significant component of the Company's depreciation, depletion and amortization, asset retirement obligation, and impairment analyses. Due to the number of estimates that rely upon reserve quantities and values, any significant changes to the Company's oil and gas reserves has a pervasive effect on the Company's consolidated financial statements, and it is therefore impracticable to estimate the effect that the adoption of the SEC's *Modernization of Oil and Gas Reporting: Final Rule* had on the Company's financial statements.

In January 2010, the FASB issued Accounting Standards Update No. 2010-03, *Oil and Gas Reserve Estimation and Disclosures* (ASU 2010-03), which provides amendments to FASB ASC Topic, *Extractive*

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Bonanza Creek Energy Company, LLC

Notes to the Consolidated Financial Statements as of December 23, 2010

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES: (CONTINUED)

Activities-Oil and Gas. The objective of ASU 2010-03 is to align the oil and gas reserve estimation and disclosure requirements of the FASB ASC with the requirements in the SEC's *Modernization of Oil and Gas Reporting: Final Rule*. The Company adopted ASU 2010-03 effective December 31, 2009, and as a result, the Company (i) has estimated its 2009 and 2010 reserve quantities using the 12-month average price, (ii) prepared its reserve estimates as of December 31, 2009 and 2010 based on the new and amended reserve definitions in ASU 2010-03 that conform to the SEC's revised reserve definitions, and (iii) reported proved undeveloped reserve quantities in Disclosure About Oil and Gas Producing Activities. Oil and gas reserve quantities or their values are a significant component of the Company's depreciation, depletion and amortization, asset retirement obligation, and proved property impairment analyses. Due to the number of estimates that rely upon reserve quantities and values, any significant changes to the Company's oil and gas reserves have a pervasive effect on the Company's consolidated financial statements, and it is therefore impracticable to estimate the effect that the adoption of ASU 2010-03 had on the Company's financial statements.

3. ACQUISITIONS AND DIVESTITURES:

In April 2008, the Company acquired all of the outstanding units in an existing LLC (MLA) for $121.2 million that owned interests in oil and gas properties and a natural gas plant located in Columbia, Lafayette and Union Counties, Arkansas. The purchase price included cash consideration of $43.6 million and the assumption of existing liabilities. The acquisition was funded by the sale of senior subordinated unsecured notes, a short term note payable, and the existing credit facility.

Supplemental Pro Forma Results (unaudited)

The following pro forma financial information represents the combined results for the Company and MLA for the year ended December 31, 2008 as if the acquisition had occurred on January 1, 2008. The pro forma financial information includes adjustments to reflect MLA as if its crude oil and natural gas properties had been accounted for under the successful efforts method of accounting. The pro forma financial information is not intended to represent or be indicative of the consolidated results of operations or financial condition of the Company that would have been reported had the acquisition been completed as of the dates presented, and should not be taken as representative of the future consolidated results of operations or financial condition of the Company.

	For the Year Ended December 31, 2008
Net revenues	$ 52,903,943
Operating income	$ (32,675,019)
Net income (loss)	$ 60,101,562

In March of 2010, the Company entered into a Purchase and Sale Agreement to sell its non-operating 50% ownership in the Jasmin property in California for approximately $7.5 million with an effective date of March 1, 2010 and closing date of March 31, 2010. The Company recorded a gain on the sale of oil and gas properties in the amount of $4 million related to this transaction. As indicated, the Jasmin property was not operated by the Company and is not a strategic oil and gas asset. The Jasmin property revenues

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Bonanza Creek Energy Company, LLC

Notes to the Consolidated Financial Statements as of December 23, 2010

3. ACQUISITIONS AND DIVESTITURES: (CONTINUED)

and direct expenses were not material to the Company's operations and the Company did not curtail any of its regional operations as a result of this sale.

4. ACCOUNTS RECEIVABLE:

Accounts receivable consists of the following:

	2010	2009
Oil and gas sales	$ 5,212,542	$ 4,872,329
Oil and gas derivative receivables		247,457
Accounts receivable from Holmes Eastern, LLC	3,665,703	
Other	368,627	114,096
Joint interest receivable	361,829	256,007
	9,608,701	5,489,889
Less: allowance for doubtful accounts	(60,000)	(333,048)
	$ 9,548,701	$ 5,156,841

5. OTHER ASSETS:

During 2010 the Company paid approximately $327,000 to novate existing hedge contracts in connection with entering into the line of credit agreement with BNP Paribas (see Note 5). As of December 23, 2010 and December 31, 2009 the Company had capitalized novation fees of approximately $2,168,000 and $1,841,000, respectively, and recorded accumulated amortization for these novation fees in the amounts of $965,000 and $562,000, respectively. These costs are being amortized on the straight-line method over the term of the derivative contracts. During 2010, the Company capitalized approximately $3,076,000 of deferred financing costs to enter into a new line of credit agreement with BNP Paribas (see Note 5). As of December 23, 2010 and December 31, 2009, the Company had capitalized deferred financing costs of approximately $10,082,000 and $7,007,000, respectively, and recorded accumulated amortization and impairment for these deferred financing costs in the amounts of $6,922,000 and $3,602,000, respectively. The costs are being amortized on the straight-line method over the term of the agreements.

In connection with the repayment of debt (see Note 1), the remaining capitalized offering costs were expensed subsequent to December 23, 2010.

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Bonanza Creek Energy Company, LLC

Notes to the Consolidated Financial Statements as of December 23, 2010

6. ACCOUNTS PAYABLE AND ACCRUED EXPENSES:

Accounts payable and accrued expenses contain the following:

	2010	2009
Drilling and completion costs	$ 2,886,438	$ 980,670
Accounts payable trade	8,186,349	2,046,233
Accounts payable to Holmes Eastern Company, LLC	353,441	
Ad valorem taxes	812,075	867,116
General and administrative	1,105,285	474,040
Lease operating expense	565,936	428,700
Interest	42,174	100,600
Accrued oil and gas hedging	197,785	84,319
Accrued reclamation	400,000	400,000
Production taxes and other	65,497	52,741
	$ 14,614,980	$ 5,434,419

7. LONG-TERM DEBT:

Senior Secured Revolving Credit Facility On May 7, 2010, the Company entered into a Senior Secured Revolving Credit Agreement, (the "Revolver"), with a syndication of banks with BNP Paribas as the administrative agent and issuing lender, which provides for borrowings of up to $200 million. The Revolver provides for interest rates plus an applicable margin to be determined based on the London Interbank Offered Rate (LIBOR) or a bank base rate ("Base Rate"), at the Company's election. LIBOR borrowings bear interest at LIBOR plus 2.25% to 3.00% depending on the utilization level, and the Base Rate borrowings bear interest at the "Bank Prime Rate," as defined plus 1.25% to 2.00%.

This Revolver was used to retire a previously existing line of credit. All remaining deferred offering costs for the previously existing line of credit were expensed.

The Revolver has a $100 million borrowing base as of December 23, 2010 and is subject to semi-annual re-determinations in May and November of each year. The Revolver provides for commitment fees of 0.5% and restricts, among other items, the payment of dividends, certain additional indebtedness, sale of assets, loans, certain investments and mergers. The Revolver also contains certain financial covenants, which require the maintenance of a minimum current ratio and a minimum debt coverage ratio and minimum interest coverage ratio, as defined. The Company was in compliance with these covenants as of December 23, 2010. The interest on the note is approximately 3% as of December 23, 2010. The Revolver is collateralized by substantially all the Company's assets and matures on May 7, 2013. As of December 23, 2010 and December 31, 2009, the outstanding amount under the Revolver is $84.4 million and $99 million, respectively. During March of 2011, the BCEI entered into a new $300 million Senior Secured Revolving Credit Agreement with an initial borrowing base of $130 million with a syndicate of banks led by BNP Paribas. Refer to Note 12, "Subsequent Events."

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Bonanza Creek Energy Company, LLC

Notes to the Consolidated Financial Statements as of December 23, 2010

7. LONG-TERM DEBT: (CONTINUED)

Senior Subordinated Unsecured Notes On May 17, 2006, the Company entered into a Note Purchase Agreement (the "Note Agreement") with Laminar which provides for the sale of up to $50 million in senior subordinated unsecured Series A notes (the "Series A Notes"). The Series A Notes bear interest based on LIBOR plus 3% payable monthly if paid in cash or LIBOR plus 4% if paid in kind (PIK). In addition, there is a floor on the LIBOR of 4%, which results in a minimum real interest rate of 7% on cash and 8% on PIK interest. The Note Agreement also provides for the issuance of warrants (the "Warrants") in connection with the sale of the Series A Notes for up to 16,525 Class A membership units.

In 2006 and 2007, the Company sold Series A Notes for $50 million and Warrants to purchase 16,525 Class A membership units at $0.01 per unit. The Company allocated $9.2 million of the proceeds received on the issuance of the Series A Notes to the Warrants "put right" (see Note 7), which represented the fair value of the Warrants on the date of issuance, and recorded the offsetting amount as a debt discount. The debt discount is being amortized over the life of the Series A Notes. Subsequent to the sale of BCEI, the Series A Notes were paid in full and retired. See to Note 1.

On July 20, 2007, the Company entered into a Amended and Restated Note Purchase Agreement (the "A&R Note Agreement") with Laminar which provides for the sale of up to an additional $20 million in Series B senior subordinated unsecured notes (the "Series B Notes"). The A&R Note Agreement extended the maturity date of the Series A Notes by one year to May 17, 2012. The A&R Note Agreement also provides the Company with the option to PIK accrued interest on the Series A and B Notes. The Company has elected to PIK all accrued interest on the Series A and B Notes. This election to PIK all accrued interest results in the interest being added to the outstanding principal of the Series A and B Notes on a monthly basis and results in no cash requirements to service the Series A and B Notes. Subsequent to the sale to BCEI, the Series B Notes were paid in full and retired. Refer to Note 1.

The Series B Notes bear interest based on the LIBOR plus 4% payable monthly in arrears or payable monthly in kind. In 2008 and 2007, the Company sold Series B Notes for approximately $20 million and Warrants to purchase 6,625 Class A membership units at $0.01 per unit. The Company allocated approximately $8.2 million of the proceeds received on the issuance of the Subordinated Unsecured Series B Notes to the Warrants "put right" (see Note 7), which represented the fair value of the Warrants on the date of issuance, and recorded the offsetting amount as a debt discount. The debt discount is being amortized over the life of the Subordinated Unsecured Notes.

In April 2008, the Company entered into a second Amended and Restated Note Purchase Agreement ("Second A&R Note Agreement") with Laminar which provides for the sale of up to an additional $30 million in Series C senior subordinated unsecured notes ("Series C Notes"). The Second A&R Note Agreement provides the Company with the option to PIK accrued interest on the Series C Notes. The Company has elected to PIK all accrued interest on the Series C Notes. This election to PIK all accrued interest results in the interest being added to the outstanding principal of the Series C Notes on a monthly basis and results in no cash requirements to service the Series C Notes. Subsequent to the sale to BCEI, the Series C Notes were paid in full and retired. See Note 1.

The Series C Notes bear interest based on the LIBOR plus 4% payable monthly in arrears or payable monthly in kind. The Company subsequently sold Series C Notes for $30 million and Warrants to purchase 9,939 Class A membership units at $0.01 per unit. The Company allocated $22.1 million of the proceeds received on the issuance of the Subordinated Unsecured Series C Notes to the Warrants "put right" (see Note 7), which represented the fair value of the Warrants on the date of issuance, and recorded the

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Bonanza Creek Energy Company, LLC

Notes to the Consolidated Financial Statements as of December 23, 2010

7. LONG-TERM DEBT: (CONTINUED)

offsetting amount as a debt discount. The debt discount is being amortized over the life of the Subordinated Unsecured Notes.

Accretion expense was recognized on the Series A, B and C Notes during 2010 and 2009 of approximately $8.9 million and $8.0 million, respectively.

Subsequent to the sale to BCEI, the Company incurred penalties of $14,327,348 for the payoff of the subordinated debentures (see Note 1).

The Note Agreements restrict, among other items, the payment of dividends, additional indebtedness, general and administrative expenses, sale of assets, loans, certain investments and mergers. The Note Agreements also contain certain financial covenants commencing on September 30, 2009, which require the maintenance of a minimum current ratio, minimum debt coverage ratios and minimum asset coverage ratio, as defined. The Company is in compliance with these covenants as of December 23, 2010. The Notes are due May 17, 2012.

As of December 23, 2010, and as of December 31, 2009, the amounts outstanding are as follows:

	2010	2009
Senior subordinated unsecured note	$ 125,145,205	$ 115,631,060
Debt discount	(14,327,348)	(23,189,303)
Total	$ 110,817,857	$ 92,441,757

A reconciliation of the changes in the Company's debt discount is as follows:

	2010	2009	2008
Beginning debt discount	$ (23,189,303)	$ (31,152,334)	$ (8,188,937)
Additional discounts from issuance of warrants			(28,949,888)
Accretion of discount debt	8,861,955	7,963,031	5,986,491
Ending debt discount	$ (14,327,348)	$ (23,189,303)	$ (31,152,334)

On May 7, 2010, the Company entered into a Second Lien Term Loan Agreement (the "Term Loan") with a group of lenders which provides for borrowing up to $30 million. The Term Loan provides for interest rates to be determined based on LIBOR (subject to a 4% floor) plus 10%. The initial borrowings under the Term Loan were $30 million, the proceeds of which were used, in part, to repay the Revolver. The Term Loan contains certain financial covenants which require the maintenance of a minimum current ratio, certain interest and debt coverage ratios, and an asset coverage ratio. The Term Loan is collateralized by a second lien on substantially all of the Company's assets and matures on May 7, 2013. As of December 23, 2010, and as of December 31, 2009, the amount outstanding was as follows:

	2010	2009
Second lien term loan	$ 30,000,000	$
Total	$ 30,000,000	$

Bonanza Creek Energy Company, LLC

Notes to the Consolidated Financial Statements as of December 23, 2010

7. LONG-TERM DEBT: (CONTINUED)

Subsequent to the sale to BCEI, the Second Lien Term Loan was paid in full and retired with approximately $3,032,000 in penalties. See Note 1.

Unsecured Subordinated Promissory Note On March 25, 2008, the Company entered into an unsecured subordinated note ("Promissory Note") with a related party for $10 million due on February 18, 2009. During 2009, this note was extended until the discharge of the Senior Obligations (as defined) has occurred. The note is subordinated to the Senior Secured Credit Facility and the Senior Secured Subordinated Notes. The Promissory Note bears a cash interest rate of 12%. Beginning in June 2009, the interest was PIK at 13%. As of December 23, 2010, the balance of the note was $12,276,228. On December 23, 2010, the Unsecured Subordinated Promissory Note was paid in full and retired. Refer to Note 1.

8. COMMITMENTS AND CONTINGENT LIABILITIES:

Office Leases Bonanza Creek rents office facilities under various noncancelable operating lease agreements. Rental expense for these leases was $537,267 in 2010, $355,461 in 2009 and $371,656 in 2008. Bonanza Creek's noncancelable operating lease agreements result in total future minimum noncancelable lease payments are presented below. Bonanza Creek also has principal payment requirements for its Line of Credit, 2^{nd} Lien Term Loan, Subordinated Debt, and the unsecured Promissory Note (assuming PIC interest at 13%) as of December 23, 2010, are also presented below:

	Office Leases	Line of Credit	2^{nd} Lien Term Loan	Subordinated Debt	Unsecured Subordinated Promissory Note	Total
2011	$ 347,437	$	$	$	$	$ 347,437
2012	294,934			125,145,205		125,440,139
2013	298,873	84,400,000	30,000,000		16,524,606	131,223,479
2014	305,438					305,438
2015 and thereafter	462,591					462,591
	$ 1,709,273	$ 84,400,000	$ 30,000,000	$ 125,145,205	$ 16,524,606	$ 257,779,084

Environmental The Company is engaged in oil and gas exploration and production and may become subject to certain liabilities as they relate to environmental cleanup of well sites or other environmental restoration procedures as they relate to the drilling of oil and gas wells and the operations. In the Company's acquisition of existing or previously drilled well bores, the Company may not be aware of what environmental safeguards were taken at the time such wells were drilled or during such time the wells were operated. Should it be determined that a liability exists with respect to any environmental clean up or restoration, the liability to cure such a violation could fall upon the Company. Management believes its properties are operated in conformity with local, state and federal regulations. No claim has been made, nor is the Company aware of any uninsured liability which the Company may have, as it relates to any environmental cleanup, restoration or the violation of any rules or regulations.

Legal Proceeding The Company may, from time to time, be involved in various other legal actions arising in the normal course of business. In the opinion of management, the Company's liability, if any, in these pending actions would not have a material adverse effect on the financial positions of the Company.

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Bonanza Creek Energy Company, LLC

Notes to the Consolidated Financial Statements as of December 23, 2010

8. COMMITMENTS AND CONTINGENT LIABILITIES: (CONTINUED)

The Company's general and administrative expenses would include amounts incurred to resolve claims made against the Company.

9. MEMBERS' DEFICIT:

Member Units Class A and Class B As of December 23, 2010 and December 31, 2009, a total of 14,090 Class A and 4,844 Class B member units, both $1.00 par value, were issued and outstanding. In connection with the transaction described in Note 1, the remaining unissued Class B member units were converted into Class A common stock of BCEI. These shares were deposited into trusts for the benefit of employees. When the shares are released from the trust and the employees are notified of the award, compensation expense will be recorded on BCEI's statement of operations.

Preferred Return Class A Members receive a preferred return that accrues at a ten percent rate per annum. The preferred return accrues on a daily basis on the actual days elapsed on 365-day per year and shall compound on each December 31. Class B members do not receive a preferred return.

Distributions Holders of Class A Member Units receive the first 100% proceeds of the distribution equal to the sum of the aggregate capital contributions and the Class A preferred return. The remaining distribution proceeds are allocated to both Class A and Class B Member Units. Class A Members Units receive 80% and Class B receive 20% of the remaining distribution based on a pro rata distribution.

Voting Rights Class A Member Units carry one vote per unit, while Class B Member Units carry no voting rights.

Liquidation Rights After payment and discharge of all debt, liabilities and obligations, Class A and Class B Members will receive the remaining proceeds based on the distribution allocation.

Warrant In 2006, 2007 and 2008, the Company issued 33,089 warrants in connection with the sale of the Senior Subordinated Unsecured Notes (see Note 5). The Warrants are exercisable at any time at $0.01 per warrant to purchase a like number of Class A membership units, until their expiration date on May 17, 2026.

The Warrants also included a "put right" whereby beginning on May 17, 2014, the unit holder, Laminar has a one-time right and option to put the Warrants back to the Company at fair market value less the exercise price. At December 31, 2009 and 2008, the estimated fair value was calculated to be $81 million and $1 million, respectively. The warrants were exercised on December 23, 2010 in connection with the transaction described in Note 1 and value at the time of exercise was approximately $47.1 million. These amounts were recorded as a warrant liability (see Note 9). A reconciliation of the changes in this liability is:

	2010	2009	2008
Balance as of beginning of period	$ 81,468,258	$ 828,392	$ 42,850,745
Additional warrants issued			28,949,888
Total unrealized (gains) loss included in earnings	(34,344,894)	80,639,866	(70,972,241)
Transfers in and out of Level 3			
Balance as of end of period	$ 47,123,364	$ 81,468,258	$ 828,392

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Bonanza Creek Energy Company, LLC

Notes to the Consolidated Financial Statements as of December 23, 2010

10. ASSET RETIREMENT OBLIGATIONS:

A reconciliation of the changes in the Company's liability is as follows:

	2010	2009	2008
Beginning asset retirement obligation	$ 1,857,486	$ 1,781,806	$ 297,229
Liabilities acquired from property acquisitions			702,599
Obligation on properties sold	(41,519)		
Liabilities incurred from new drilling	307,220		44,752
Revisions	2,746,405	(16,574)	619,951
Liabilities settled	(44,758)	(41,664)	(12,495)
Accretion expense	141,532	133,918	129,770
Ending asset retirement obligation	$ 4,966,366	$ 1,857,486	$ 1,781,806

In 2010, the Company revised its estimated cost for plugging and abandoning wells and recorded a $2.7 million increase to asset retirement obligations. The upward revision is related to revised engineering estimates for the cost to plug, abandon, and reclaim well locations in California.

11. FAIR VALUE MEASUREMENTS:

The Company follows FASB ASC 820, *Fair Value Measurements and Disclosures*, which defines fair value, establishes a framework for using fair value to measure assets and liabilities, and expands disclosures about fair value measurements. The statement establishes a hierarchy for inputs used in measuring fair value that maximizes the use of observable inputs and minimizes the use of unobservable inputs by requiring that the most observable inputs be used when available. Observable inputs are inputs that market participants would use in pricing the asset or liability developed based on market data obtained from sources independent of the Company. Unobservable inputs are inputs that reflect the Company's assumptions of what market participants would use in pricing the asset or liability developed based on the best information available in the circumstances. The hierarchy is broken down into three levels based on the reliability of the inputs as follows:

Level 1: Quoted prices are available in active markets for identical assets or liabilities;

Level 2: Quoted prices in active markets for similar assets and liabilities that are observable for the asset or liability; or

Level 3: Unobservable pricing inputs that are generally less observable from objective sources, such as discounted cash flow models or valuations.

ASC 820 requires financial assets and liabilities to be classified based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

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Bonanza Creek Energy Company, LLC

Notes to the Consolidated Financial Statements as of December 23, 2010

11. FAIR VALUE MEASUREMENTS: (CONTINUED)

The following table presents the Company's financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 23, 2010 by level within the fair value hierarchy:

	Fair Value Measurements Using		
	Level 1	Level 2	Level 3
Commodity derivative assets	$	$ 1,149,976	$ 2,531,656
Commodity derivative liabilities	$	$ 8,885,247	$
Warrant liabilities	$	$	$ 47,123,364

The following table presents the Company's financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2009 by level within the fair value hierarchy:

	Fair Value Measurements Using		
	Level 1	Level 2	Level 3
Commodity derivative assets	$	$ 558,297	$ 6,786,280
Commodity derivative liabilities	$	$ 9,754,968	$
Warrant liabilities	$	$	$ 81,468,258

The Company's commodity swaps are valued based on the counterparty's mark-to-market statements, which are validated by observable transactions for the same or similar commodity options using the NYMEX futures index, and are designated as Level 2 within the valuation hierarchy. The Company's collars, which are designated as Level 3 within the valuation hierarchy, are also valued based on the counterparty's mark-to-market statements, but are not validated by observable transactions with respect to volatility. The counterparty in all of the commodity derivative financial instruments is the lender on the Company's senior secured revolving credit facility (Note 7).

The rollforward for the Company's warrants which were designated as Level 3 within the valuation hierarchy as of December 23, 2010 and December 31, 2009 is presented in Note 9. The rollforward of the Level 3 commodity collar is presented below:

Balance as of January 1	$ 6,786,280
Realized gains and losses	(4,254,624)
New derivatives	
Balance as of December 23	$ 2,531,656

The Company recognizes an estimated liability for future costs associated with the abandonment of its oil and gas properties. The Company's asset retirement obligation is initially measured using primarily Level 3 inputs. The significant unobservable inputs include the cost of abandoning oil and gas wells, the economic lives of its properties, the inflation rate, and the credit adjusted risk-free rate. The Company bases its estimate of the liability on its historical experience and current estimated costs.

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Bonanza Creek Energy Company, LLC

Notes to the Consolidated Financial Statements as of December 23, 2010

12. DERIVATIVE COMMODITY CONTRACTS:

As of December 23, 2010, the Company's derivative commodity contracts with BNP Paribas are as follows:

Contract Term	Notional Volume	Floor	Ceiling	Fixed Price
January 1 - December 31, 2011	15,392 Bbl./Month	$ 90.00	$ 123.00	
January 1 - December 31, 2012	13,956 Bbl./Month	$ 90.00	$ 123.00	
January 1 - April 30, 2013	12,654 Bbl./Month	$ 90.00	$ 123.00	
January 1 - December 31, 2011	8,917 Bbl./Month			$ 64.45
January 1 - December 31, 2012	8,206 Bbl./Month			$ 62.95
January 1 - October 31, 2013	7,542 Bbl./Month			$ 61.50
January 1 - December 31, 2011	18,298 MMBTU/Month			$ 7.10
January 1 - December 31, 2012	16,860 MMBTU/Month			$ 6.75
January 1 - October 31, 2013	15,481 MMBTU/Month			$ 6.40

The table below contains a summary of all the Company's derivative positions reported on the consolidated balance sheet as of December 23, 2010:

Derivatives	Balance Sheet Location	Fair Value
Asset		
Commodity derivatives	Current derivative assets	$ 1,465,545
Commodity derivatives	Long-term derivative assets	2,216,087
Liability		
Commodity derivatives	Current derivative liability	(3,598,869)
Commodity derivatives	Long-term derivative liability	(5,286,378)
Total		$ (5,203,615)

Realized gains and losses on commodity derivatives and the unrealized gains or losses are recorded in other income (expense).

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Bonanza Creek Energy Company, LLC

Notes to the Consolidated Financial Statements as of December 23, 2010

13. DISCLOSURES ABOUT OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED):

BCEC's oil and natural gas activities are entirely within the United States. Costs incurred in oil and natural gas producing activities are as follows:

	2010	2009	2008
Unproved property acquisition	$ 751,387	$ 67,491	$ 1,439,070
Proved property acquisition	273,275	582,815	39,406,861
Development(a)	27,385,767	6,765,085	31,348,342
Exploration(b)	8,691,755	482,159	7,520,313
Total	$ 37,102,184	$ 7,897,550	$ 79,714,586

(a) Development costs include workover costs of $2,213,333, $504,230, and $459,314 charged to lease operating expense during 2010, 2009, and 2008, respectively.

(b) Exploration costs include $266,332, $131,059, and $25,278 charged to exploration expense during 2010, 2009, and 2008, respectively.

During 2010, 2009 and 2008, additions to oil and gas properties of approximately $307,220, $0, and $747,351 were recorded for the estimated costs of future abandonment related to new wells drilled or acquired.

Exploratory wells in progress as of each year end were not significant to the Company's financial statements.

In December 2008, the SEC published the final rules and interpretations updating its oil and gas reporting requirements. The Company adopted the rules effective December 31, 2009, and the rule changes, including those related to pricing and technology, are included in the company's reserve estimates.

In January 2010, the FASB aligned ASC Topic 932 with the aforementioned SEC requirements. Please refer to the section entitled "Adopted and Recently Issued Accounting Pronouncements" under Note 2 Summary of Significant Accounting Policies for additional discussion regarding both adoptions.

The estimate of proved reserves and related valuations for the years ended December 31, 2010 and 2009 were based upon reports prepared by Cawley, Gillespie & Associates, Inc. Petroleum Consultants. The estimate of proved reserves and related valuations for the year ended December 31, 2008 was prepared by MHA Petroleum Consultants, Inc. independent petroleum engineers. The estimates of proved reserves are inherently imprecise and are continually subject to revision based on production history, results of additional exploration and development, price changes and other factors.

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Bonanza Creek Energy Company, LLC

Notes to the Consolidated Financial Statements as of December 23, 2010

13. DISCLOSURES ABOUT OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED): (CONTINUED)

All of BCEC's oil and natural gas reserves are attributable to properties within the United States. A summary of BCEC's changes in quantities of proved oil and natural gas reserves for the years ended December 31, 2008, 2009 and 2010 are as follows:

	Oil (MBbl)	Natural Gas (MMcf)
Balance January 1, 2008	7,019	6,903
Extensions and discoveries	478	712
Purchases of minerals in place	4,258	12,220
Production	(476)	(682)
Revisions to previous estimates(a)	1,177	753
Balance December 31, 2008	12,456	19,906
Extensions and discoveries	3,694	9,470
Production	(564)	(939)
Revisions to previous estimates	(316)	(827)
Balance December 31, 2009	15,270	27,610
Extensions and discoveries	2,250	5,023
Sales of minerals in place	(568)	
Production	(595)	(1,309)
Revisions to previous estimates(b)	319	9,900
Balance December 31, 2010	16,676	41,224
Proved developed reserves:		
December 31, 2008	4,905	7,164
December 31, 2009	4,710	7,021
December 31, 2010	6,465	13,703
Proved undeveloped reserves:		
December 31, 2008	7,551	12,742
December 31, 2009	10,560	20,589
December 31, 2010	10,211	27,521

(a) In 2008, net revisions to previous estimates of 1,303 MBoe resulted primarily from well results and extensive engineering and geological reviews of the Mid-Continent properties that led to a change in planned development well spacing from 20 acres to 10 acres.

(b) In 2010, net revisions to previous estimates of 1,969 MBoe were due primarily to positive price changes and changes to the rate forecasts for wells in the Mid-Continent region based on results from improved stimulation techniques in smaller, tighter, higher gas oil ratio sands that led to increased gas reserves and slightly higher NGL reserves.

The standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves and the changes in standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves were prepared in accordance with the provisions of ASC Topic 932. Future cash

Bonanza Creek Energy Company, LLC

Notes to the Consolidated Financial Statements as of December 23, 2010

13. DISCLOSURES ABOUT OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED): (CONTINUED)

inflows were computed by applying prices to estimated future production. Future production and development costs are computed by estimating the expenditures to be incurred in developing and producing the proved oil and natural gas reserves at year-end, based on costs and assuming continuation of existing economic conditions.

Future income tax expenses are calculated by applying appropriate year-end tax rates to future pretax net cash flows relating to proved oil and natural gas reserves. Future income tax expenses give effect to permanent differences, tax credits and loss carryforwards relating to the proved oil and natural gas reserves. Future net cash flows are discounted at a rate of 10% annually to derive the standardized measure of discounted future net cash flows. This calculation procedure does not necessarily result in an estimate of the fair market value or the present value of BCEC's oil and natural gas properties.

The standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves are as follows (in thousands):

	2010	2009	2008
Future cash flows	$ 1,366,948	$ 932,676	$ 612,530
Future production costs	(434,498)	(346,119)	(234,453)
Future development costs	(222,007)	(177,297)	(163,103)
Future income tax expense	(126,005)	(44,293)	(1,961)
Future net cash flows	584,438	364,967	213,013
10% annual discount for estimated timing of cash flows	(299,329)	(179,263)	(129,092)
Standardized measure of discounted future net cash flows	$ 285,109	$ 185,704	$ 83,921

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

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Bonanza Creek Energy Company, LLC

Notes to the Consolidated Financial Statements as of December 23, 2010

13. DISCLOSURES ABOUT OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED): (CONTINUED)

The changes in the standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves are as follows (in thousands):

	2010	2009	2008
Beginning of year	$ 185,704	$ 83,921	$ 171,217
Sale of oil and gas produced, net of production costs	(31,916)	(18,844)	(25,633)
Net changes in prices and production costs	97,725	44,531	(110,024)
Extensions, discoveries and improved recoveries	45,498	79,186	5,634
Development costs incurred	21,615	6,261	30,889
Changes in estimated development cost	(30,350)	2,974	(101,988)
Purchases of mineral in place			59,440
Sales of mineral in place	(10,972)		
Revisions of previous quantity estimates	38,058	(6,816)	12,299
Net change in income taxes	(38,932)	(21,765)	42,466
Accretion of discount	20,368	8,469	21,445
Changes in production rates and other	(11,689)	7,787	(21,824)
End of year	$ 285,109	$ 185,704	$ 83,921

Average wellhead prices in effect at December 31, 2008, inclusive of adjustments for quality and location were used in determining future net revenues related to the standardized measure calculation. The average wellhead prices inclusive of adjustments for quality and location used in determining future net revenues related to the standardized measure calculation as of December 31, 2009 and 2010 were calculated using the first-day-of-the-month price for each of the 12 months that made up the reporting period.

	2010	2009	2008
Oil (per Bbl)	$ 74.77	$ 57.79	$ 41.91
Gas (per Mcf)	$ 4.72	$ 3.42	$ 4.99

14. SUBSEQUENT EVENTS:

During February 2011, BCEI received approximately $1 million as payment in full of the note receivable from Patriot Resources, LLC, the operator of the Sargent field in California. During March of 2011, BCEI entered into a new $300 million Senior Secured Revolving Credit Agreement with an initial borrowing base of $130 million with a syndicate of banks led by BNP Paribas. On March 24, 2011, BCEI entered into a new oil derivative commodity contract with Societe General with a floor price of $80.00 per Bbl with a ceiling price of $140.00 per Bbl covering 800 Bbl per day from April 1, 2011 through December 31, 2011.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Managers
Holmes Eastern Company, LLC

We have audited the balance sheets of Holmes Eastern Company, LLC as of December 23, 2010 and December 31, 2009 and the related statements of income and retained earnings, and cash flows for the period January 1, 2010 to December 23, 2010 and the period from inception (May 1, 2009) to December 31, 2009. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Holmes Eastern Company, LLC as of December 23, 2010 and December 31, 2010, are its results of operations and its cash flows for the period January 1, 2010 to December 23, 2010 and for the period from inception (May 1, 2009) to December 31, 2009 in conformity with U.S. generally accepted accounting principles.

/s/ Hein & Associates LLP

Denver, Colorado
July 21, 2011

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HOLMES EASTERN COMPANY, LLC

BALANCE SHEETS

	December 23, 2010	December 31, 2009
ASSETS		
CURRENT ASSETS:		
Cash and equivalents	$	$ 1,734,300
Receivables:		
Oil and gas sales	2,497,985	1,768,135
Joint interest receivable and other	2,563,291	1,132,786
Prepaid expenses and other	31,885	119,473
Inventory		99,572
Total current assets	5,093,161	4,854,266
OIL AND GAS PROPERTIES at cost, using the successful efforts method:		
Proved properties	36,285,240	23,955,105
Wells in progress	1,786,917	1,832,005
Less: accumulated depletion, depreciation and amortization	(4,039,965)	(1,095,201)
	34,032,192	24,691,909
PROPERTY AND EQUIPMENT, net of accumulated depletion and depreciation of $7,541 and $3,000, respectively	17,574	22,115
OTHER ASSETS, net	367,164	4,715
TOTAL ASSETS	$ 39,510,091	$ 29,573,005
LIABILITIES AND MEMBERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable and accrued liabilities	$ 2,221,763	$ 3,921,145
Payable to Bonanza Creek Energy Company, LLC	3,665,703	15,961
Oil and gas revenue distributions payable	1,337,544	616,092
Notes payable related party		6,500,000
Total current liabilities	7,225,010	11,053,198
LONG-TERM LIABILITIES:		
Bank debt	7,200,000	
Ad valorem taxes	262,027	579,361
Asset retirement obligation	639,452	700,350
TOTAL LIABILITIES	15,326,489	12,332,909

COMMITMENTS AND CONTINGENCIES (Notes 1, 4 and 5)		
MEMBERS' EQUITY:		
Member units (15,661 units issued and outstanding)	15,661,000	15,661,000
Retained earnings	8,522,602	1,579,096
Total members' equity	24,183,602	17,240,096
TOTAL LIABILITIES AND MEMBERS' EQUITY	$ 39,510,091	$ 29,573,005

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HOLMES EASTERN COMPANY, LLC

STATEMENTS OF OPERATIONS AND RETAINED EARNINGS

	For the Period from January 1, 2010 to December 23, 2010	For the Period from Inception (May 1, 2009) to December 31, 2009
NET REVENUES:		
Oil and gas sales	$ 13,957,560	$ 4,961,126
OPERATING EXPENSES:		
Lease operating	2,010,187	1,174,621
Severance and ad valorem taxes	834,282	288,970
Exploration and lease rentals	19,234	4,597
Depreciation, depletion and amortization	3,005,888	1,133,321
General and administrative	639,598	351,891
Total operating expenses	6,509,189	2,953,400
INCOME FROM OPERATIONS	7,448,371	2,007,726
INTEREST EXPENSE	(439,171)	(428,630)
OTHER INCOME (LOSS)	(65,694)	
TOTAL OTHER INCOME AND (EXPENSE)	(504,865)	(428,630)
NET INCOME	6,943,506	1,579,096
RETAINED EARNINGS, beginning	1,579,096	
RETAINED EARNINGS, ending	$ 8,522,602	$ 1,579,096

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HOLMES EASTERN COMPANY, LLC

STATEMENTS OF CASH FLOWS

	For the Period January 1, 2010 to December 23, 2010	For the Period from Inception (May 1, 2009) to December 31, 2009
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 6,943,506	$ 1,579,096
Adjustments to reconcile net income to net cash from operating activities:		
Depreciation, depletion and amortization	3,005,888	1,133,321
Amortization of deferred financing costs	117,386	
Other		(13,174)
Changes in operating assets and liabilities:		
Increase in accounts receivable	(2,160,355)	(2,352,696)
(Increase) in prepaid expense and other	87,588	
Increase (decrease) in current liabilities	(589,358)	2,435,967
Net cash provided by operating activities	7,404,655	2,782,514
CASH FLOWS FROM INVESTING ACTIVITIES:		
Acquired assets, net of assumed liabilities		(20,948,073)
Exploration and development of oil and gas properties	(13,024,823)	(2,256,426)
Net cash used in investing activities	(13,024,823)	(23,204,499)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Equity issuance		15,661,000
Increase in bank revolving credit	11,600,000	
Payment on bank revolving credit	(4,400,000)	
Increase in note payable related party		6,500,000
Payment on note payable	(6,500,000)	
Deferred financing costs	(479,835)	(4,715)
Increase in payable to Bonanza Creek Energy Company, LLC	3,665,703	
Net cash provided by financing activities	3,885,868	22,156,285
NET CHANGE IN CASH AND EQUIVALENTS	(1,734,300)	1,734,300
CASH AND EQUIVALENTS, beginning of period	1,734,300	
CASH AND EQUIVALENTS, end of period	$	$ 1,734,300
SUPPLEMENTAL CASH FLOW DISCLOSURE:		
Changes in working capital related to drilling expenditures and property acquisition	$ (728,308)	$ 1,622,365

Cash paid for interest	$	228,759	$	
Asset retirement obligation	$	111,039	$	665,230