Bonanza Creek Energy, Inc.
Form 10-K
March 22, 2012

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

ý **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2011

OR

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

Commission file number:

Bonanza Creek Energy, Inc.

(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**61-1630631** (I.R.S. Employer Identification No.)
410 17th Street, Suite 1500 **Denver, Colorado** (Address of principal executive offices)	**80202** (Zip Code)

(720) 440-6100
(Registrant's telephone number, including area code)

Securities Registered Pursuant to Section 12(b) of the Act:

(Title of Class)	**(Name of Exchange)**
Common Stock, par value $0.001 per share	New York Stock Exchange

Securities Registered Pursuant to Section 12(g) of the Act: **None**

Indicate by check mark if the Registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes o No ý

Indicate by check mark if the Registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes o No ý

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ý No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ý No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of Registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. 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.

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

Indicate by check mark whether the Registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes o No ý

Aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter: The aggregate market value of the voting common equity held by non-affiliates of the registrant on December 15, 2011, based upon the closing price of $13.61 of the registrant's common stock as reported on the New York Stock Exchange, was approximately $157,705,453. Excludes approximately 27.6 million shares of the registrant's common stock held by current executive officers, directors, and stockholders that the registrant has concluded are affiliates of the registrant. The registrant has elected to use December 15, 2011 as the calculation date, which was the initial trading date of the registrant's common stock on the New York Stock Exchange, because on June 30, 2011 (the last business day of the registrant's second fiscal quarter), the registrant was a privately-held company.

Number of shares of registrant's common stock outstanding as of March 15, 2012: 39,477,584

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FOR THE YEAR ENDED DECEMBER 31, 2011

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Information Regarding Forward-Looking Statements

This Annual Report on Form 10-K contains various statements, including those that express belief, expectation or intention, as well as those that are not statements of historic fact, that are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities and Exchange Act of 1934, as amended. These forward-looking statements may include projections and estimates concerning our capital expenditures, our liquidity and capital resources, our estimated revenues and losses, the timing and success of specific projects, outcomes and effects of litigation, claims and disputes, our business strategy and other statements concerning our operations, economic performance and financial condition. When used in this Annual Report on Form 10-K, the words "could," "believe," "anticipate," "intend," "estimate," "expect," "may," "continue," "predict," "potential," "project" and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. We have based these forward-looking statements on certain assumptions and analyses we have made in light of our experience and our perception of historical trends, current conditions and expected future developments as well as other factors we believe are appropriate under the circumstances. The actual results or developments anticipated by these forward-looking statements are subject to a number of risks and uncertainties, many of which are beyond our control, and may not be realized or, even if substantially realized, may not have the expected consequences.

Forward-looking statements may include statements about:

- 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;

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- access to adequate gathering systems and pipeline take-away capacity to execute our drilling program;
- our ability to secure firm transportation for oil and natural gas we produce and to sell the oil and natural gas at market prices;
- costs associated with perfecting title for mineral rights in some of our properties;
- continued hostilities in the Middle East and other sustained military campaigns or acts of terrorism or sabotage; and
- other economic, competitive, governmental, legislative, regulatory, geopolitical and technological factors that may negatively impact our businesses, operations or pricing.

All forward-looking statements speak only as of the date of this Annual Report on Form 10-K. We disclaim any obligation to update or revise these statements unless required by law, and you should not place undue reliance on these forward-looking statements. Although we believe that our plans, intentions and expectations reflected in or suggested by the forward-looking statements we make in this Annual Report on Form 10-K are reasonable, we can give no assurance that these plans, intentions or expectations will be achieved. We disclose important factors that could cause our actual results to differ materially from our expectations under "Item 1A. Risk Factors" and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and elsewhere in this Annual Report on Form 10-K. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

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GLOSSARY OF OIL AND NATURAL GAS TERMS

The terms defined in this section are used throughout this Annual Report on Form 10-K:

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

"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

"Bbl" One stock tank barrel, of 42 U.S. gallons liquid volume, used herein in reference to crude oil, condensate or natural gas liquids.

"Bcf" One billion cubic feet of natural gas.

"Boe" Barrels of oil equivalent, with 6,000 cubic feet of natural gas being equivalent to one barrel of oil.

"British thermal unit" The heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

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

"Completion" The process of treating a drilled well followed by the installation of permanent equipment for the production of natural gas or oil, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

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

"Developed reserves" Reserves of any category that can be expected to be recovered through existing wells with existing equipment and operating methods or for which the cost of required equipment is relatively minor when compared to the cost of a new well. Also referred to as "developed oil and gas reserves."

"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.

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

"Dry hole" A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

"Economically producible" A resource that generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation.

"Environmental assessment" An 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 or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.

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

"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.

"MBbl" One thousand barrels of crude oil, condensate or natural gas liquids.

"MBoe" One thousand barrels of oil equivalent.

"Mcf" One thousand cubic feet of natural gas.

"MMBoe" One million barrels of oil equivalent.

"MMBtu" One million British thermal units.

"MMcf" One million cubic feet of natural gas.

"NYMEX" The New York Mercantile Exchange.

"Net acres" The percentage of total acres an owner has out of a particular number of acres, or a specified tract. An owner who has 50% interest in 100 acres owns 50 net acres.

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

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

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"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.

"Pooling" Pooling is a provision in an oil and gas lease that allows the operator to combine the leased property with properties owned by others. (Pooling is also known as unitization.) The separate tracts are joined to form a drilling unit. Ownership shares are issued according to the acreage contributed or by the production capabilities of each producing well for fields in later stages of development.

"Productive well" A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.

"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 reserves" Proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Also referred to as "proved developed producing reserves."

"Proved reserves" and "proved oil and gas reserves" Under SEC rules for fiscal years ending after December 31, 2009, proved reserves are defined as:

> Those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.
>
> The area of the reservoir considered as proved includes (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.
>
> In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons, LKH, as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.
>
> Where direct observation from well penetrations has defined a highest known oil, HKO, elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

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Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities.

Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Under SEC rules for fiscal years ending prior to December 31, 2009, proved reserves are defined as:

The estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions. Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (A) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any, and (B) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir. Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the proved classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based. Estimates of proved reserves do not include the following: (A) Oil that may become available from known reservoirs but is classified separately as indicated additional reserves; (B) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; (C) crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and (D) crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.

"Proved undeveloped reserves" Proved reserves 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.

"PUD" Proved undeveloped drilling locations.

"PV-10" When used with respect to oil and natural gas reserves, PV-10 means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development and abandonment costs, using prices and costs in effect at the determination date, before income taxes, and without giving effect to non-property-related expenses, discounted to a present value using an annual discount rate of 10% in accordance with the guidelines of the Commission.

"Reasonable certainty" A high degree of confidence.

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"Recompletion" The process of re-entering an existing wellbore that is either producing or not producing and completing new reservoirs in an attempt to establish or increase existing production.

"Reserves" Estimated remaining 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.

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

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

"Spacing" The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres, e.g., 40-acre spacing, and is often established by regulatory agencies. Also referred to as "well spacing."

"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 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 oil and gas reserves."

"Unit" The joining of all or substantially all interests in a reservoir or field, rather than a single tract, to provide for development and operation without regard to separate property interests. Also, the area covered by a unitization agreement.

"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 lessee of a property to explore for and to produce and own oil, gas, or other minerals. The working interest owners bear the exploration, development, and operating costs on either a cash, penalty, or carried basis.

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PART I

Item 1. *Business.*

Overview

Bonanza Creek Energy, Inc. ("BCEI" or, together with our consolidated subsidiaries, the "Company," "we," "us," or "our") 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 Wattenberg Field 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 99.5% and hold an average working interest of approximately 80.7% of our proved reserves, providing us with significant control over the rate of development of our long-lived, low-cost asset base.

As of December 31, 2011, we accumulated 81,174 net leasehold acres across our properties. We are currently focused on exploiting what we have identified as significant resource potential from the Niobrara and Codell formations in the Wattenberg Field located in Colorado, and the oily portion of the Cotton Valley formation in Southern Arkansas. We believe the location, size and concentration of our acreage in our core project areas create an opportunity for us to achieve cost, recovery and production efficiencies through the development of our project inventory. In 2011, we drilled and completed 106 gross operated wells and 6 non-operated gross wells and had 3 development wells and 3 exploration wells in progress. For those wells drilled and completed, we achieved 100% success in the finding of hydrocarbons, all of which are economic based on current prices as of December 31, 2011. This success has been achieved through the application of the latest drilling, fracturing and completion techniques.

Cawley, Gillespie & Associates, Inc., our independent reserve engineers, estimated our net proved reserves as of December 31, 2011, to be as follows:

Estimated Proved Reserves	Crude Oil (MBbls)	Natural Gas (MMcf)	Natural Gas Liquids (MBbls)	Total Proved (MBoe)
Developed				
Mid-Continent	5,042	14,783	1,237	8,743
Rocky Mountain	5,310	16,530		8,065
California	253			253
Undeveloped				
Mid-Continent	5,926	27,457	2,358	12,860
Rocky Mountain	7,661	34,212		13,363
California	429			429
Total Proved	24,621	92,982	3,595	43,713

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Our average net daily production rate during December 2011 was 6,076 Boe/d, which consisted of 70.4% oil and natural gas liquids.

	Estimated Proved Reserves at December 31, 2011[1]					Estimated Production for the Month Ended December 31, 2011			
	Total Proved (MBoe)	% of Total	% Proved Developed	% Oil and Liquids	PV-10 ($ in MM)[2]	Average Net Daily Production (Boe/d)	% of Total	Projected 2012 Capital Expenditures (millions)	Net Proved Undeveloped Drilling Locations as of December 31, 2011
Mid-Continent	21,603	49.4%	40.5%	67.4%	$ 410.9	3,609	59.4%	$ 79	116.1
Rocky Mountain	21,428	49.0	37.6	60.5	366.8	2,323	38.2	170	159.4
California	682	1.6	37.1	100.0	16.3	144	2.4	1	11.5
Total	43,713	100.0%	39.0%	64.5%	$ 794.0	6,076	100%	$ 250	287.0

(1) Proved reserves and related future net revenue and PV-10 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 $96.19 per Bbl of crude oil and an average price of $4.12 per MMBtu of natural gas. Adjustments were then made for location, grade, transportation, gravity, and Btu content, as appropriate for the underlying resource, which resulted in a decrease of $6.39 per Bbl of crude oil and an increase of $0.70 per MMBtu of natural gas respectively.

(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 " Reconciliation of PV-10 to Standardized Measure."

Our History

Bonanza Creek Energy, Inc. was incorporated on December 2, 2010 pursuant to the laws of the State of Delaware. On December 23, 2010, in connection with an investment from Project Black Bear LP ("Black Bear"), an entity advised by West Face Capital Inc. ("West Face Capital") and certain clients of Alberta Investment Management Corporation ("AIMCo"), we acquired Bonanza Creek Energy Company, LLC ("BCEC") and Holmes Eastern Company, LLC ("HEC"), which transactions we refer to as our "Corporate Restructuring." We completed the initial public offering of our common stock in December 2011 (our "IPO") pursuant to which 10,000,000 shares of our common stock were sold.

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 Wattenberg Field. Substantially all of these infill locations are characterized by multiple productive horizons.

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Exploit Additional Development Opportunities. We are evaluating additional resource potential opportunities that could result in future development projects on several of our assets. We are evaluating extended length laterals in the Niobrara and horizontal drilling in the Codell formations of the Wattenberg Field. In addition, we have evaluated and believe we may achieve attractive returns by exploiting the Lower Smackover (Brown Dense) trend in our southern Arkansas acreage. We have 5,672 net acres prospective for the Brown Dense.

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 gas processing facilities and 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 approximately 1,200 drilling locations of which 400 gross (287.0 net) are proved, providing us with multiple years of drilling inventory.

Niobrara Resource Potential. We have accumulated 62,688 net acres in Weld and Jackson Counties, Colorado, targeting the Niobrara and Codell formations. Our acreage is proximate to horizontal drilling operations which have been successfully completed by other operators and we successfully drilled and completed 4 horizontal wells in 2011 which averaged 30 day rates of 469 Boe/d. 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. 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 Wattenberg Field acreage position have been mitigated by the high volume of data provided through the drilling, completion and production of thousands of vertical wells in the Niobrara in close proximity to and within our acreage. We own proprietary 3-D seismic surveys on 17,400 acres of our properties in Weld County and 22 proprietary 2-D seismic lines in Jackson County. Adequate gathering systems are in place in the Wattenberg Field, 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 80.7% and operate approximately 99.5% of our estimated proved reserves, which allows us to employ the drilling and completion techniques we believe to be most effective, manage costs and control the timing and allocation of our capital expenditures.

Gas Processing Capability in Southern Arkansas. The processing of our natural gas at our McKamie facility improves our well development economics in southern Arkansas. In addition, in 2011 we expanded our infrastructure by adding an additional gas processing facility in our Dorcheat Macedonia field and plan to further expand this facility in 2012 to accommodate future drilling on our acreage in this region.

Management Team with Proven Operating and Acquisition Skills. Our senior management team has extensive expertise in the oil and gas industry. Our senior technical team has an average of more than 30 years of industry experience, including experience in multiple North American resource

plays as well as experience in other North American and international basins. We believe our management and technical team is one of our principal competitive strengths relative to our industry peers due to our team's proven track record in identification, acquisition and execution of resource conversion opportunities. In addition, this team possesses substantial expertise in horizontal drilling techniques and fracture stimulation experience.

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. Our liquidity as of December 31, 2011 was approximately $215.5 million, comprised of $213.4 million of availability under our credit facility and approximately $2.1 million of cash on hand.

Our Operations

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

Mid-Continent Region

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, 2011, our estimated proved reserves in this region were 21,602.3 MBoe, 67.4% of which were oil and natural gas liquids and 40.5% of which were proved developed. We currently operate 146 gross (127.5 net) producing wells and, as of December 31, 2011, have an identified drilling inventory of approximately 141 gross (116.1 net) PUD drilling locations on our acreage. During 2011, we drilled 42 gross (37.2 net) wells in the Dorcheat Macedonia and McKamie Patton fields and completed 39 gross (34.4 net) of them by December 31, 2011.

Dorcheat Macedonia. In the Dorcheat Macedonia field, we average an 85.3% working interest and 70.6% net revenue interest, and all of our acreage is held by production. We have approximately 111 gross (94.7 net) producing wells and our average net daily production during December 2011 was approximately 2,289 Boe/d from a proved reserves base of 14,625 MBoe, of which about 60.6% 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.

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. 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, 2011, we have identified approximately 139 gross (114.1 net) PUD drilling locations on our acreage in this area. Currently, we have budgeted for 2012 capital expenditures of $56.0 million for the development of our Dorcheat Macedonia acreage. Under this budget, we expect to drill and complete 38 gross (31.7 net) additional infill PUD locations in the field in 2012 with a complete cost per well of approximately $1.8 million, approximately $1.7 million of which will be for initial drilling and completion. During 2011, we drilled 40 gross (35.2 net) vertical Cotton Valley wells in Dorcheat Macedonia.

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. As of

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December 31, 2011, our estimated proved reserves in these fields were approximately 1,628.8 MBoe, and average net daily production during December 2011 was approximately 199 Boe/d. During 2011, we drilled 2 gross (2.0 net) vertical Cotton Valley wells in McKamie-Patton.

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

In order to accommodate increased gas volumes, we invested $19.0 million to build a 12.5 MMcf/d processing facility with associated 28,000 gallons per day of natural gas liquids capacity in our Dorcheat Macedonia field, which we completed in September 2011. The construction of this new facility is in conjunction with our continued development of the field. In November 2011, we executed an agreement for an additional expansion of this facility. We expect this facility to be online in January 2013 at an aggregate cost of approximately $20 million.

Combined, our Arkansas gas facilities had an average net output of 1,121 Boe/d based on the facility contracts for the month of December 2011. Our ownership of this facility and pipeline system provides us with the benefit of controlling processing and compression of our natural gas production and timing of connection to our newly completed wells. While we own the majority of the gas entering the facility, we also process some third-party natural gas through the system. Neither the revenue nor volumes of this third-party natural gas is included in our reserve reports.

Rocky Mountain Region

The two main areas in which we operate in the Rocky Mountain region are the Wattenberg Field in Weld County, Colorado and the North Park Basin in Jackson County, Colorado. We hold 83,617 gross (62,688 net) acres in these two areas that currently produce oil, natural gas and CO_2 from the Niobrara, Codell, J-Sand, D-Sand, Pierre B and Dakota formations. As of December 31, 2011, our estimated proved reserves in this region were 21,427.4 MBoe, of which 60.5% were oil and 37.6% were proved developed.

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

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.

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The Wattenberg Field is believed to occupy the most prospective area of the Niobrara. Within the Wattenberg Field, the Niobrara oil shale is 200 to 300 feet thick and comprises the Smoky Hill Shale and Fort Hayes Limestone. In addition to the Wattenberg Field, 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.

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

Commercial development activities began in the Wattenberg Field 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.

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

Our estimated proved reserves in the Wattenberg Field were 20,817 MBoe at December 31, 2011. As of December 31, 2011, we had a total of 193 gross (187.0 net) producing wells and our net average daily production during December 2011 was approximately 2,205 Boe/d. Our working interest for all producing wells averages 96.9% and our net revenue interest is approximately 79.2%.

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 $725,000 and we expect to incur an additional $230,000 per well for refracture stimulation, to be completed in the fifth year after initial completion. As of December 31, 2011, we have identified approximately 219 gross (134.3 net) PUD vertical drilling locations on our acreage in this area.

The Codell sandstone and Niobrara oil shale are blanket deposits in the Wattenberg Field. We continue to expand our proved acreage with our vertical program by drilling non-proved locations. Currently, we estimate our capital expenditures for 2012 will be $64.3 million, which includes drilling 92 gross (84.5 net) vertical wells of which 55 are proved and 37 are non-proved. During 2011, we drilled and completed 66 gross (63.8 net) wells, 14 proved and 52 non-proved.

We intend to employ a mixture of vertical and horizontal drilling techniques with multi-stage fracture completions across our entire acreage position in the Wattenberg Field. Our entire 42,218 gross (29,262 net) acre position in the Wattenberg Field is prospective for the Niobrara formation using horizontal drilling and multi-stage fracture completion technology. On the eastern portion of our acreage, we have 3-D seismic data covering 17,400 gross acres, in addition to having drilled 19 vertical wells and currently operating 31 vertical wells.

For the year ended December 31, 2011, we drilled and completed 4 gross (3.9 net) operated horizontal Niobrara wells which had average 30-day rates of 469 Boe/d. On average, these wells cost approximately $4.0 million each. For 2012, we plan to drill and complete 24 gross (19.7 net) wells in the Wattenberg Field at an estimated cost of approximately $82.4 million in the aggregate.

North Park Basin Jackson County, Colorado. We control 41,399 gross (33,426 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.

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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, 2011 were approximately 610.6 MBoe, of which 100% were oil. Our average net production during December 2011 was approximately 119 Boe/d. None of our CO_2 production is currently reflected in our reserve reports. Our development and testing of the North Park Basin began in 2011 with the drilling of 2 gross (2.0 net) vertical wells at a drilling and evaluation cost of approximately \$2.6 million for the first well and \$4.1 million for the second well as of December 31, 2011.

In 2012, we plan to drill and complete 3 gross (3.0 net) wells in the North Park Basin at a cost of approximately \$16.3 million in the aggregate. We also plan to acquire approximately 14,700 acres of 3-D seismic surveys in this area. All of our 41,399 gross (33,426 net) acres in the North Park Basin are prospective for the Niobrara oil shale. 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. As of December 31, 2011, our estimated proved reserves in California were 682 MBoe, of which 100.0% were oil and 37.0% were proved developed. As of December 31, 2011, we had a total of 47 gross (38.1 net) producing wells and our average net daily production was approximately 143 Boe/d. Our working interest for all producing wells averages 81.1% and our net revenue interest is approximately 68.8%. We have identified approximately 14 gross (11.5 net) PUD drilling opportunities in these fields. Currently, we estimate our capital expenditures for 2012 in this area will be \$1.0 million.

We believe the opportunity to see additional growth exists on the two thermal properties: Kern River and Midway Sunset. Proved reserves for these two areas are only 453 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. During 2011, the operator at Sargent drilled 3 gross (1.5 net) wells of which 2 gross (1.0 net) were fractured stimulated.

Estimated Proved Reserves

Unless otherwise specifically identified, the summary data with respect to our estimated proved reserves presented below has been prepared by our independent reserve engineering firm in accordance with rules and regulations of the Securities and Exchange Commission (the "SEC") applicable to companies involved in oil and natural gas producing activities. As discussed below, the SEC adopted

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new rules relating to disclosures of estimated reserves that were effective for fiscal years ending on or after December 31, 2009. Our proved reserve estimates do not include probable or possible reserves which may exist, categories which the new SEC rules now permit us to disclose in public reports. Our estimated proved reserves under the SEC rules in effect for the year ended December 31, 2009 were determined using constant prices and unescalated costs based on the prices received and costs incurred on a field-by-field basis as of the year end. For the years ended December 31, 2010 and 2011 and for future periods, our estimated proved reserves were and will be determined using the preceding twelve months' unweighted arithmetic average of the first-day-of-the-month prices, rather than year-end prices. For a definition of proved reserves under the SEC rules for both the fiscal years ending on or after December 31, 2010 and the fiscal year ending December 31, 2009, please see the "Glossary of oil and natural gas terms" included in the beginning of this report.

The table below summarizes our estimated proved reserves and related PV-10 at December 31, 2011 and 2010 for each of our project areas. All of the reserve estimates at December 31, 2011 and 2010 presented in the table below are based on reports prepared by Cawley Gillespie & Associates, Inc., our independent reserve engineers. In preparing its reports, Cawley Gillespie & Associates, Inc. evaluated properties representing all of our PV-10 at December 31, 2011 and 2010 under the new SEC rules. For more information regarding our independent reserve engineers, please see "   Independent Reserve Engineers" below. The information in the following table does not give any effect to or reflect our commodity derivatives.

	At December 31, 2011		**At December 31, 2010**	
Project Area	**Proved Reserves (MMBoe)**	**PV-10(1)**	**Proved Reserves (MMBoe)**	**PV-10(1)**
		(In millions)		**(In millions)**
Mid-Continent	21.6	$ 410.9	22.9	$ 313.4
Rocky Mountain	21.4	366.8	9.1	135.3
California	0.7	16.3	0.9	12.9
Total	43.7	$ 794.0	32.9	$ 461.6

(1) 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 "   Reconciliation of PV-10 to Standardized Measure."

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The following table sets forth more information regarding our estimated proved reserves at December 31, 2011, 2010 and 2009:

	At December 31,		
	2011	**2010**	**2009[1]**
Reserve Data[2]:			
Estimated proved reserves:			
Oil (MMBbls)	28.2	22.4	15.3
Natural gas (Bcf)	93.0	62.9	27.6
Total estimated proved reserves (MMBoe)[3]	43.7	32.9	19.9
Percent oil	65%	68%	77%
Estimated proved developed reserves:			
Oil (MMBbls)	11.8	8.2	4.7
Natural gas (Bcf)	31.3	20.1	7.0
Total estimated proved developed reserves (MMBoe)	17.0	11.6	5.9
Percent oil	69%	71%	80%
Estimated proved undeveloped reserves:			
Oil (MMBbls)	16.4	14.2	10.6
Natural gas (Bcf)	61.7	42.8	20.6
Total estimated proved undeveloped reserves (MMBoe)	26.7	21.3	14.0
PV-10 (in millions)[4]	$ 794.0	$ 461.6	$ 208.2
Standardized Measure (in millions)[5]	$ 666.2	$ 374.7	$ 185.7

(1)
The amounts presented as of December 31, 2009 represent those amounts from BCEC, a predecessor company, and are included for comparative purposes only.

(2)
Proved reserves and related future net revenues, PV-10 and Standardized Measure 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 $96.19 per Bbl of crude oil and an average price of $4.12 per MMBtu of natural gas, $79.43 per Bbl of crude oil and an average price of $4.38 per MMBtu of natural gas and $61.18 per Bbl of crude oil and an average price of $3.87 per MMBtu of natural gas for the years ended December 31, 2009, 2010 and 2011 respectively. Adjustments were made for location and the grade of the underlying resource.

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

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

(5)
Standardized Measure represents the present value of estimated future net cash flows from proved oil and natural gas reserves, less estimated future development, production, plugging and abandonment costs and income tax expenses (if applicable), discounted at 10% per annum to reflect timing of future cash flows. In connection with our Corporate Restructuring, we merged into a corporation that is treated as a taxable entity for federal income tax purposes. For further discussion of income taxes, see Note 9 to our audited consolidated financial statements.

Estimated proved reserves at December 31, 2011 were 43.7 MMBoe, a 33% increase from estimated proved reserves of 32.9 MMBoe at December 31, 2010. The increase is primarily due to

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extensions and discoveries associated with the Rocky Mountain region and is comprised of 168 new proved undeveloped locations and 54 unproved locations that were drilled in year 2011 and moved directly to proved reserves. Another component of the increase was our commodity price assumption for oil which increased $16.76/Bbl to $96.19/Bbl for the year ended December 31, 2011 from $79.43/Bbl for the year ended December 31, 2010.

Estimated proved reserves at December 31, 2010 were 32.9 MMBoe, a 65% increase from reserves of 19.9 MMBoe at December 31, 2009. The increase is primarily due to 9.3 MMBoe acquired from Holmes Eastern Company, LLC in connection with our Corporate Restructuring and accretive drilling and positive reserve revisions from our predecessor Bonanza Creek Energy, Company, LLC. Another component of the increase was our commodity price assumption for oil which increased $18.25/Bbl to $79.43/Bbl for the year ended December 31, 2010 from $61.18/Bbl for the year ended December 31, 2009.

Our PV-10 as of December 31, 2011 was 794.0 million, a 72% increase from PV-10 of $461.6 million at December 31, 2010. The increase in PV-10 during the period was primarily related to commodity price assumption for oil which increased $16.76/Bbl to $96.19/Bbl which increased PV-10 by approximately $123.1 million and positive extensions and discoveries in the Rocky Mountain region which increased PV-10 by approximately $204 million.

Our PV-10 as of December 31, 2010 was $461.6 million, a 122% increase from PV-10 of $208.2 million at December 31, 2009. The increase in PV-10 during the period was related to $115 million of PV-10 value acquired from Holmes Eastern Company, LLC in connection with our Corporate Restructuring, approximately $97.7 million of the increase was related to commodity price assumption for oil which increased $18.25/Bbl to $79.43/Bbl from $61.18/Bbl at December 31, 2009, and approximately $66 million of the increase was related to revisions to previous quantity estimates for our predecessor BCEC. These increases in PV-10 were offset by an $11 million decrease for sales of minerals in place and a decrease of $9 million for the net change in estimated future development cost.

The following table sets forth the estimated future net revenues, excluding derivative contracts, from proved reserves, the present value of those net revenues (PV-10) and the expected benchmark prices used in projecting net revenues at December 31, 2011, 2010 and 2009:

	At December 31,		
	2011	2010	2009
	(In millions)		
Future net revenues	$ 1,315.0	$ 787.5	$ 365.0
Present value of future net revenues:			
Before income tax (PV-10)	794.0	461.6	208.2
After income tax (Standardized Measure)[1]	666.2	374.7	185.7
Benchmark oil price($/Bbl)[2]	$ 96.19	$ 79.43	$ 61.18

(1) Standardized Measure represents the present value of estimated future net cash inflows from proved oil and natural gas reserves, less estimated future development, production, plugging and abandonment costs and income tax expenses (if applicable), discounted at 10% per annum to reflect timing of future cash flows. For further discussion of income taxes, see Note 9 to our audited consolidated financial statements.

(2) 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. Adjustments were made for location and the grade of the underlying resource.

Future net revenues represent projected revenues from the sale of proved reserves net of production and development costs (including operating expenses and production taxes). Such calculations at December 31, 2011 and 2010 are based on costs in effect at December 31 of each year

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and the 12-month unweighted arithmetic average of the first-day-of-the-month price for the period January through December of such year, without giving effect to derivative transactions, and are held constant throughout the life of the properties. Such calculations at December 31, 2009 are based on costs and prices in effect at December 31, 2009, without giving effect to derivative transactions, and are held constant throughout the life of the properties. There can be no assurance that the proved reserves will be produced within the periods indicated or that prices and costs will remain constant. There are numerous uncertainties inherent in estimating reserves and related information and different reservoir engineers often arrive at different estimates for the same properties.

Reconciliation of PV-10 to Standardized Measure

PV-10 is derived from the Standardized Measure of discounted future net cash flows, which is the most directly comparable GAAP financial measure. PV-10 is a computation of the Standardized Measure on a pre-tax basis. PV-10 is equal to the Standardized Measure at the applicable date, before deducting future income taxes, discounted at 10%. We believe that the presentation of PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to our estimated net proved reserves prior to taking into account future corporate income taxes, and it is a useful measure for evaluating the relative monetary significance of our oil and natural gas properties. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies. We use this measure when assessing the potential return on investment related to our oil and natural gas properties. PV-10, however, is not a substitute for the Standardized Measure. Our PV-10 measure and the Standardized Measure do not purport to present the fair value of our oil and natural gas reserves.

The following table provides a reconciliation of PV-10 to the Standardized Measure at December 31, 2011, 2010 and 2009:

	December 31,		
	2011	**2010**	**2009**(1)
	(In millions)		
PV-10	$ 794.0	$ 461.6	$ 208.2
Present value of future income taxes discounted at 10%(2)	(127.8)	(86.9)	(22.5)
Standardized Measure	$ 666.2	$ 374.7	$ 185.7

(1) The amounts presented as of December 31, 2009 represent those amounts for our predecessor BCEC.

(2) Both our predecessor BCEC and HEC were partnerships for federal income tax purposes and, therefore, were not subject to entity-level taxation. Historically, federal or state corporate income taxes have been passed through to the members of each of BCEC and HEC. 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, 2009 and 2010, assuming we had been subject to entity-level tax and further assuming an estimated combined 38.5% federal and state income tax rate.

Proved Undeveloped Reserves

At December 31, 2011, our proved undeveloped reserves were 26,652 MBoe, an increase of 5,317.4 Mboe over our December 31, 2010 proved undeveloped reserves of 21,334.6 MBoe. The reserve change and number of net wells is summarized in the table below for each of our regions. The largest changes were realized in the Rocky Mountain region resulting primarily from 168 new proved undeveloped locations of which 53 locations were related to our 2011 drilling program and 115 20 acre locations were moved from unproved to proved undeveloped. The growth in the Rocky Mountain region was

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offset by drilling approximately 53 proved undeveloped locations in the Dorcheat field in the Mid-Continent region which resulted in a corresponding increase to proved developed reserves. Our total capital expenditure associated with the conversion of proved undeveloped reserves to proved developed reserves in 2011 was $93.9 million.

	Proved Undeveloped Reserves					
	2011		2010		Difference	
Region/Area	MBoe	Net Wells	MBoe	Net Wells	MBoe	Net Wells
Mid Continent	12,859.4	116.1	16,890.2	151.3	(4,030.8)	(35.2)
Rocky Mountain	13,362.5	159.4	3,897.6	77.3	9,464.9	82.1
California	430.1	11.5	546.7	13.6	(116.6)	(2.1)
Total	26,652.0	287.0	21,334.5	242.2	5,317.5	44.8

Technology used to establish proved reserves

Under the new SEC rules, proved reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations. The term "reasonable certainty" implies a high degree of confidence that the quantities of oil and/or natural gas actually recovered will equal or exceed the estimate. Reasonable certainty can be established using techniques that have been 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, 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. For wells and locations targeting the Niobrara formation, the evaluation included an assessment of the beneficial impact of the use of multi-stage hydraulic fracture stimulation treatments on estimated recoverable reserves. In addition to assessing reservoir continuity, geologic data from well logs, core analyses and seismic data related to the formation were used to estimate original oil in place.

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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 of Engineering and Planning, Gary A. Grove, is the technical person primarily responsible for overseeing the preparation of our reserves estimates. Mr. Grove has over 29 years of industry experience with positions of increasing responsibility in engineering and evaluations and holds a Bachelor of Science degree in petroleum engineering.

Throughout each fiscal year, the reserve committee of our board of directors and our technical team meet with representatives of our independent reserve engineering firm to review properties and discuss methods and assumptions used in preparation of the proved reserves estimates. The reserve committee meets at least twice each year to discuss and evaluate the valuation and accumulation of data process.

Our technical team also works with our banking syndication members at least twice each year, for a valuation of our reserves by the banks in our lending group and their engineers in determining the borrowing base under our revolving credit facility.

Independent Reserve Engineers

The proved reserves estimate for the Company for the years ended December 31, 2010 and 2011 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.

Production, Revenues and Price History

Oil and natural gas are commodities. The price that we receive for the oil and natural gas we produce is largely a function of market supply and demand. Demand for oil and natural gas in the United States has increased dramatically over the last ten years. Natural gas prices have declined over the last three years as a result of a global economic downturn and increased supplies of natural gas.

Demand is impacted by general economic conditions, weather and other seasonal conditions, including hurricanes and tropical storms. Over or under supply of oil or natural gas can result in substantial price volatility. Historically, commodity prices have been volatile and we expect that volatility to continue in the future. A substantial or extended decline in oil or natural gas prices or poor drilling results could have a material adverse effect on our financial position, results of operations, cash flows, quantities of oil and natural gas reserves that may be economically produced and our ability to access capital markets.

The following table sets forth information regarding oil and natural gas production, revenues and realized prices and production costs for the periods indicated. For additional information on price

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calculations, please see information set forth in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

	2009	2010	2011
Oil:			
Production (MBbls)	507.4	484.9	953.0
Average sales price (per Bbl), including hedges	$ 67.40	$ 73.73	$ 86.69
Average sales price (per Bbl), excluding hedges	$ 54.40	$ 75.27	$ 90.56
Natural Gas:			
Production (MMcf)	939.0	1,351.5	2,776.4
Average sales price (per Mcf), including hedges	$ 5.05	$ 4.76	$ 5.09
Average sales price (per Mcf), excluding hedges	$ 3.91	$ 4.99	$ 4.84
Natural Gas Liquids:			
Production (MBbls)	69.1	129.8	183.8
Average sales price (per Bbl), including hedges	$ 41.77	$ 56.23	$ 67.23
Average sales price (per Bbl), excluding hedges	$ 41.77	$ 56.23	$ 67.23
Oil Equivalents:			
Production (MBoe)	733.0	840.0	1,599.5
Average daily production (Boe/d)	2,008	2,301	4,382
Average Production Costs (per Boe)[(1)]	$ 18.35	$ 18.19	$ 13.43

(1) Excludes ad valorem and severance taxes.

Principal Customers

Two of our customers, Lion Oil and Plains Marketing comprised 35% and 45%, respectively, of total revenue for the year ended December 31, 2011. Lion Oil and Plains Marketing, comprised 52% and 30%, respectively, of total revenue for the year ended December 31, 2010.

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 December 31, 2011.

	Oil		Natural Gas(1)		Total		Operated	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Mid-Continent	147	127.8			147	127.8	146	127.5
Rocky Mountain	255	245.7			255	245.7	250	244.0
California	47	38.1			47	38.1	34	31.6
Total	449	411.6			449	411.6	430	403.1

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

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Acreage

The following table sets forth certain information regarding the developed and undeveloped acreage in which we own a working interest as of December 31, 2011 for each of our project areas. Acreage related to royalty, overriding royalty and other similar interests is excluded from this summary.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Mid-Continent	14,980	13,474			14,980	13,474
Rocky Mountain	37,058	29,868	46,559	32,820	83,617	62,688
California	8,740	4,868	200	144	8,940	5,012
Total	60,778	48,210	46,759	32,964	107,537	81,174

Undeveloped acreage

The following table sets forth the number of gross and net undeveloped acres as of December 31, 2011 that will expire over the next three years by project area unless production is established within the spacing units covering the acreage prior to the expiration dates:

	Expiring 2012		Expiring 2013		Expiring 2014	
	Gross	Net	Gross	Net	Gross	Net
Mid-Continent						
Rocky Mountain	2,119	2,119	11,453	11,453	36	36
California	20	16	100	48		
Other						
Total	2,139	2,135	11,543	11,501	36	36

In 2011, federal and state leases covering 6,308 acres in our Rocky Mountain region expired, of which 5,604 acres were in North Park and 714 acres were in the Wattenberg field.

Drilling Activity

Exploratory

The following table describes the exploratory wells we drilled during the years ended December 31, 2009, 2010 and 2011.

	Productive Wells		Dry Wells		Total	
Year	Gross	Net	Gross	Net	Gross	Net
2009						
2010	15	15.0			15	15.0
2011	58	55.6			58	55.6

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Development

The following table describes the development wells we drilled during the years ended December 31, 2009, 2010 and 2011.

	Productive Wells		Dry Wells		Total	
Year	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
2009(1)						
2010(1)	27	27.0			27	27.0
2011	59	53.1			59	53.1

(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, in which we had a minority working interest.

Present Activity

The following table describes drilling activities as of December 31, 2011.

	Development Wells		Exploratory Wells		Total	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Mid-Continent	3	2.8			3	2.8
Rocky Mountain			3	3	3	3
California					0.0	0.0
Total	3	2.8	3	3	6	5.8

Capital expenditure budget

In 2011, we incurred $165.5 million of capital expenditures. This was an increase from our predecessor operations due to funds generated from our Corporate Restructuring.

Our total anticipated 2012 capital expenditure budget is approximately $250 million, which consists of approximately:

- $220 million for drilling and completing operated wells;
- $20 million for the extension and expansion of our gas processing facilities in Arkansas; and
- $10 million for recompletions of wells in Arkansas, re-fracture stimulating wells in Colorado and additional facility projects throughout the Company.

While we have budgeted approximately $250 million for these purposes, the ultimate amount of capital we will expend may fluctuate materially based on market conditions and the success of our drilling results as the year progresses. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources."

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 February 29, 2012, we had the following economic hedges in place, which settle monthly:

Oil Contracts

Period	Type	Volume/Month (Bbls)	Index(1)	Floor	Ceiling	Fixed Price
March 1 - December 31, 2012	Collar	67,956	WTI	$ 90.00	$ 106.45	
March 1 - December 31, 2012	Swap	9,692	WTI			$ 63.03
January 1 - December 31, 2013	Collar	34,218	WTI	$ 92.10	$ 108.91	
January 1 - October 31, 2013	Swap	7,542	WTI			$ 61.50

Natural Gas Contracts

Period	Type	Volume/Month (MMBtu)	Index	Fixed Price
March 1 - December 31, 2012	Swap	16,808	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 NYMEX.

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.

Bonanza Creek Acquisition History

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

Mid-Continent. In April 2008, BCEC 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.

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Rocky Mountain. BCEC completed four Wattenberg Field 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 Wattenberg Field, including 39 operated and 3 non-operated wells primarily completed in the Codell/Niobrara formations. BCEC 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, BCEC 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.

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 transportation for 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.

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.

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.

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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 Interstate Commerce Act, or 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 and for the five year period beginning July 1, 2011, 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 2.65%. The FERC order approving the currently effective index rate challenged before the Court of Appeals for the District of Columbia Circuit in *Valero Marketing Supply Co. v. FERC*, Case No. 11-1266 (D.C. Cir.), but the petitioners voluntarily dismissed the case on December 7, 2011.

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.

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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. In 2008, FERC issued Order No. 712, which removed price ceilings for short-term releases of one year or less and exempted from bidding and certain other conditions releases to asset managers who meet specified conditions.

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 are 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, 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. On October 24, 2011, the Fifth Circuit issued its decision in *Texas Pipeline Association v. Federal Energy Regulatory Commission*, No. 10-60066 (5th Cir. filed Oct. 24, 2011), in which it vacated FERC Order Nos. 720 and 720-A on the basis that FERC did not have statutory authority under the NGA to require intrastate pipelines to disclose and disseminate capacity and scheduling information. It is not known whether FERC intends to seek review of the decision by the United States Supreme Court.

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 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. The scope of the "in connection with" standard is the subject of ongoing litigation.

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.

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. Further, it is not uncommon for neighboring landowners and other third parties to file other 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 classified 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 do 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 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.

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There have been recent initiatives to strengthen and expand pipeline safety regulations and to increase penalties for violations. In December 2011, both Houses of the U.S. Congress passed bipartisan legislation providing for more stringent oversight of pipelines and increased penalties for violations of safety rules. In addition, the Pipeline and Hazardous Materials Safety Administration has announced an intention to strengthen its rules.

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.

Since August 2010, the U.S. Environmental Protection Agency, or the EPA, has published several new regulations under the CAA to control emissions from stationary internal combustion engines. Over time, those rules may require us to undertake certain expenditures and activities, likely including paying higher prices for new engines; installing emissions control equipment, such as oxidation catalysts or non-selective catalytic reduction equipment, on a portion of our existing engines located at major sources of hazardous air pollutants and all our existing engines over a certain size regardless of location; following prescribed maintenance practices for engines; and implementing additional emissions testing and monitoring.

On July 28, 2011, the EPA proposed rules that would establish new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, the EPA's proposed rule package included New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds ("VOCs") and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The proposed rules also would establish specific new requirements regarding emissions from compressors, dehydrators, storage tanks and other production equipment. In addition, the rules would establish new leak detection requirements for natural gas processing plants. The EPA is accepting public comment on the proposed rules and must take final action on the rules by April 3, 2012. The final rules could require modifications to our operations or increase our capital and operating costs without being offset by increased product capture. At this point, we cannot predict the final regulatory requirements or the cost to comply with such requirements.

Climate change

The United States is a party to the United Nations Framework Convention on Climate Change, an international treaty focused on stabilizing GHG 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 GHG 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 GHG. Any future federal laws, treaties or implementing regulations that may be adopted to address GHG emissions could require us to incur increased operating costs and could adversely affect demand for the oil and natural gas we produce.

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In addition, the EPA has begun to regulate GHG emissions. In December 2009, the EPA published its finding that certain emissions of GHG 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 GHG under existing provisions of the federal Clean Air Act. Consequently, the EPA is requiring a reduction in emissions of GHG 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 GHG in their permits if they emit at least 75,000 tons of these emissions per year. In July 2012, the rule expands to include all new facilities that emit at least 100,000 tons of GHG per year.

In addition, in October 2009, the EPA issued a final rule requiring the reporting of GHG 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, 2010, the EPA published a final rule expanding the existing GHG monitoring and reporting rule to include certain large 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 GHG from, our equipment and operations could require us to incur costs to reduce emissions of GHG 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 GHG, primarily through the planned development of GHG emission inventories and/or GHG cap and trade programs. For example, California's cap and trade regulations took effect on January 1, 2012, with enforcement expected to begin in 2013, which will allow the State to refine the requirements in the interim. Although most of the state-level initiatives have to date focused on large sources of GHG emissions, such as coal-fired electric plants, it is possible that smaller sources of emissions could become subject to GHG emission limitations or allowance purchase requirements in the future. Any one of these climate change regulatory and legislative initiatives could have a material adverse effect on our business, financial condition 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 GHG 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 certain surface waters. Pursuant to the CWA and analogous state laws, permits must be obtained to discharge pollutants into state waters or waters of the U.S. 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 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 certain hydraulic fracturing from the definition of "underground injection." However, the U.S.

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Senate and House of Representatives have considered bills to repeal this exemption. If enacted, hydraulic fracturing operations could be required to meet permitting and financial assurance requirements, adhere to certain construction specifications, fulfill monitoring, reporting, and recordkeeping obligations, meet plugging and abandonment requirements, and provide public disclosure of chemicals used in the fracturing process. If the exemption for hydraulic fracturing is removed from the SDWA, or if other restrictions on fracturing are enacted at the federal, state or local level, there could be a significant impact on our financial condition and results of operations.

Federal agencies are also considering regulation of hydraulic fracturing. The EPA recently asserted regulatory authority over hydraulic fracturing involving diesel additives under the SDWA's Underground Injection Control Program and is developing guidance for how permitting authorities should handle such activities. In addition, on October 21, 2011, the EPA announced its intention to propose regulations by 2014 under the federal Clean Water Act to regulate wastewater discharges from hydraulic fracturing and other natural gas production. The 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 has also announced its intention to propose a new rule regulating hydraulic fracturing activities on federal lands, including requirements for disclosure, well bore integrity and handling of flowback water.

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. The State of Colorado recently adopted regulations regarding hydraulic fracturing which went into effect April 1, 2012. These regulations require disclosure of all chemicals used in hydraulic fracturing fluid, subject to certain methods to protect proprietary information. The regulations allow disclosure through the FracFocus web site, which is operated jointly by the Interstate Oil & Gas Compact Commission and the Ground Water Protection Council. The State of Colorado, in response to an EPA request, has also asked 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, 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 Wattenberg Field in 1999. At our Dorcheat Macedonia 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 60 fracture stimulations since acquiring our Dorcheat Macedonia properties in mid-2008. We expect that approximately 91% of our total acreage held as of December 31, 2011 will be subject to hydraulic fracturing in one or more reservoirs, which corresponds to approximately 62% of our total proved reserves. 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 $400,000) in our Mid-Continent region and 46% (or $440,000) 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 $186.9 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 material 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. 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.

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

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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 would create substantial uncertainty about our ability to meet future drilling plans and thus production and capital expenditure targets.

Employees

As of December 31, 2011, we employed 96 people, including 17 experienced and degreed engineers and geoscientists with an average industry experience of 27 years. Our future success will depend partially on our ability to attract, retain and motivate qualified personnel. We are not a party to any collective bargaining agreements and have not experienced any strikes or work stoppages. We consider our relations with our employees to be satisfactory. From time to time, we utilize the services of independent contractors to perform various field and other services.

Offices

As of December 31, 2011, we leased 14,716 square feet of office space in Denver, Colorado at 410 17th Street, where our principal offices are located. We also have leases for field offices in Houston, Texas, Bakersfield, California, Stamps, Arkansas and Kersey, Colorado totaling 13,682 square feet.

Available information

We are required to file annual, quarterly and current reports, proxy statements and other information with the SEC. You may read and copy any documents filed by us with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Our filings with the SEC are also available to the public from commercial document retrieval services and at the SEC's website at http://www.sec.gov.

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Our common stock is listed and traded on the New York Stock Exchange under the symbol "BCEI." Our reports, proxy statements and other information filed with the SEC can also be inspected and copied at the New York Stock Exchange, 20 Broad Street, New York, New York 10005.

We also make available on our website at http://www.bonanzacrk.com all of the documents that we file with the SEC, free of charge, as soon as reasonably practicable after we electronically file such material with the SEC. Information contained on our website, other than the documents listed below, is not incorporated by reference into this Annual Report on Form 10-K.

Item 1A. *Risk Factors.*

Our business involves a high degree of risk. If any of the following risks, or any risk described elsewhere in this Annual Report on Form 10-K, actually occurs, our business, financial condition or results of operations could suffer. The risks described below are not the only ones facing us. Additional risks not presently known to us or which we currently consider immaterial also may adversely affect us.

Risks related to the oil and natural gas industry and our business

A decline in oil and, to a lesser extent, 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, to a lesser extent, 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 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 conditions impacting the global supply and demand for oil and natural gas;
- the actions of OPEC;
- the price and quantity of imports of foreign oil and natural gas;
- political conditions in or affecting other oil-producing and natural gas-producing countries, including the current conflicts in the Middle East and conditions in South America and Russia;
- 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;

technological advances affecting energy consumption; and

the price and availability of alternative fuels.

Substantially all of our production is sold to purchasers under short-term (less than 12-month) 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. See " Our exploration, development and exploitation projects require substantial capital expenditures. We may be unable to obtain needed capital or

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financing on satisfactory terms, which could lead to expiration of our leases or a decline in our oil and natural gas reserves" below. Lower oil and natural gas prices may also reduce the amount of oil and natural gas that we can produce economically and may affect our proved reserves. See also " 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" below.

Further, oil prices and natural gas prices do not necessarily fluctuate in direct relationship to each other. Because approximately 64.5% of our estimated proved reserves as of December 31, 2011 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, 2011, the daily NYMEX WTI oil spot price ranged from a high of $110.29 per Bbl to a low of $85.52 per Bbl, and the NYMEX natural gas Henry Hub spot price ranged from $3.24 to $4.51 per MMBtu.

Additionally, as of December 31, 2011, we had commodity price hedging agreements on approximately 42% of our estimated Boe production. To the extent we are unhedged or our hedge parties default in their obligations, we have significant exposure to adverse changes in the prices of oil and natural gas that could materially and adversely affect our results of operations.

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

Our future financial condition and results of operations will depend on the success of our exploitation, exploration, development and production activities. Our oil and natural gas exploration and production activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil or natural gas production. Our decisions to purchase, explore, develop or otherwise exploit drilling locations or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. For a discussion of the uncertainty involved in these processes, see " 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" below. Our cost of drilling, completing and operating wells is often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical. Further, many factors may curtail, delay or cancel our scheduled drilling projects, including the following:

- shortages of or delays in obtaining equipment and qualified personnel;
- facility or equipment malfunctions;
- unexpected operational events;
- pressure or irregularities in geological formations;
- adverse weather conditions, such as blizzards and ice storms;
- reductions in oil and natural gas prices;
- delays imposed by or resulting from compliance with regulatory requirements;
- proximity to and capacity of transportation facilities;
- title problems; and

limitations in the market for oil and natural gas.

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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.

The process of estimating oil and natural gas reserves is complex. 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 Annual Report on Form 10-K. See "Item 1. Business Estimated Proved Reserves" for information about our estimated oil and natural gas reserves and the PV-10 and Standardized Measure as of December 31, 2011, 2010 and 2009.

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 extent, 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. Although the reserve information contained herein is reviewed by independent reserve engineers, estimates of oil and natural gas reserves are inherently imprecise.

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 Annual Report on Form 10-K. 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. Due to the limited production history of our undeveloped acreage, the estimates of future production associated with such properties may be subject to greater variance to actual production than would be the case with properties having a longer production history.

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.

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. In accordance with new SEC requirements for the years ended December 31, 2011, 2010 and 2009 we based the estimated discounted future net revenues from our proved reserves on the 12-month unweighted arithmetic average of the first-day-of-the-month price for 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:

- actual prices we receive for oil and natural gas;
- actual cost of development and production expenditures;

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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 Annual Report on Form 10-K. If oil prices decline by $10.00/Bbl, then our PV-10 as of December 31, 2011 would decrease by approximately $129 million.

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

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

The results of our drilling in new or emerging formations, such as horizontal drilling in the Niobrara oil shale, are more uncertain initially than drilling results in areas or using technologies 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.

The unavailability or high cost of additional drilling rigs, equipment, supplies, personnel and oilfield services could adversely affect our ability to execute our exploration and development plans within our budget and on a timely basis.

Shortages or the high cost of drilling rigs, equipment, supplies, personnel or oilfield services could delay or adversely affect our development and exploration operations or cause us to incur significant expenditures that are not provided for in our capital budget, which could have a material adverse effect on our business, financial condition or results of operations.

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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 expiration of our leases or a decline in our oil and natural gas reserves.

Our exploration and development activities are capital intensive. We make and expect to continue to make substantial capital expenditures in our business for the development, exploitation, production and acquisition of oil and natural gas reserves. Our cash flows used in investing activities were $158.9 million and $36.6 million (including $1.8 million and $1.1 million for the acquisition of oil and gas properties) related to capital and exploration expenditures for the years ended December 31, 2011 and 2010, respectively. Our capital expenditure budget for 2012 is approximately $250 million, with approximately $220 million allocated for drilling and completion operations. 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.

A significant improvement in oil and gas prices could result in an increase in our capital expenditures. We intend to finance our future capital expenditures primarily through cash flows provided by operating activities and borrowings under our revolving credit facility. Our financing needs may require us to alter or increase our capitalization substantially through the issuance of additional equity securities, debt securities or the sale of non-strategic assets. The issuance of additional debt or equity may require that a portion of our cash flows provided by operating activities be used for the payment of principal and interest on our debt, thereby reducing our ability to use cash flows to fund working capital, capital expenditures and acquisitions. The issuance of additional equity securities could have a dilutive effect on the value of our common stock. In addition, upon the issuance of certain debt securities (other than on a borrowing base redetermination date), our borrowing base under our revolving credit facility would be reduced.

Our cash flows provided by operating activities and access to capital are subject to a number of variables, including:

- our proved reserves;
- the level of oil and natural gas we are able to produce from existing wells;
- the prices at which our oil and natural gas are sold;
- the costs of developing and producing our oil and natural gas production;
- our ability to acquire, locate and produce new reserves;
- the ability and willingness of our banks to lend; and
- our ability to access the equity and debt capital markets.

If the borrowing base under our revolving credit facility or our revenues decrease as a result of lower 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 on terms favorable to us, or at all. If cash generated by operations or cash available under our revolving 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 drilling locations, which in turn could lead to a possible expiration of our leases and a decline in our oil and natural gas reserves, and could adversely affect our business, financial condition and results of operations.

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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 revolving 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 revolving credit facility and our results of operations for the periods in which such charges are taken.

Our business depends on oil and natural gas gathering and transportation facilities, most of which are owned by third parties.

The marketability of our oil and natural gas production depends in part on the availability, proximity and capacity of gathering and pipeline systems owned by third parties. The disruption of third-party facilities due to maintenance, weather or other interruptions of service could also negatively impact our ability to market and deliver our products. We have no control over when or if such facilities are restored.

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

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

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

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

The development of our proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our undeveloped reserves may not be ultimately developed or produced.

Approximately 61% of our total proved reserves were classified as proved undeveloped as of December 31, 2011. Development of these reserves may take longer and require higher levels of capital expenditures than we currently anticipate. Delays in the development of our reserves or increases in costs to drill and develop such reserves will reduce the PV-10 value of our estimated proved undeveloped reserves and future net revenues estimated for such reserves and may result in some projects becoming uneconomic. In addition, delays in the development of reserves could cause us to have to reclassify our proved reserves as unproved reserves.

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Unless we replace our oil and natural gas reserves, our reserves and production will decline, which would adversely affect our business, financial condition and results of operations.

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.

According to estimates included in our December 31, 2011 proved reserve report, if on January 1, 2012 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 31.6% 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.

Market conditions or operational impediments may hinder our access to oil and natural gas markets or delay our production.

Market conditions or the unavailability of satisfactory oil and natural gas transportation arrangements may hinder our access to oil and natural gas markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends, in substantial part, on the availability and capacity of gathering systems, pipelines and processing facilities owned and operated by third-parties. Our failure to obtain such services on acceptable terms could materially harm our business. We may be required to shut in wells due to lack of a market or inadequacy or unavailability of crude oil or natural gas pipelines or gathering system capacity. If our production becomes shut-in for any of these or other reasons, we would be unable to realize revenue from those wells until other arrangements were made to deliver the products to market.

We may incur substantial losses and be subject to substantial liability claims as a result of our oil and natural gas operations. Additionally, we may not be insured for, or our insurance may be inadequate to protect us against, these risks.

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition or results of operations. Our oil and natural gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil and natural gas, including the possibility of:

- environmental hazards, such as spills, uncontrollable flows of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater and shoreline contamination;

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

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

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- abnormally pressured formations resulting in well blowouts, fires or explosions;
- mechanical difficulties, such as stuck oilfield drilling and service tools and casing collapse;
- cratering (catastrophic failure);
- personal injuries and death; and
- natural disasters.

Any of these risks could adversely affect our ability to conduct operations or result in substantial losses to us as a result of:

- injury or loss of life;
- damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage;
- regulatory investigations and penalties;
- suspension of our operations; and
- repair and remediation costs.

At one of our Arkansas properties, we produce a small amount of gas from seven 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. We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. 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.

Because 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.

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

We describe some of our drilling locations and our plans to explore those drilling locations in this Annual Report on Form 10-K. Our drilling locations are in various stages of evaluation, ranging from a location which is ready to drill to a location that will require substantial additional interpretation. There is no way to predict in advance of drilling and testing whether any particular location will yield oil or natural gas in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in sufficient quantities to be economically viable. Even if sufficient amounts of oil or natural gas exist, we may damage the potentially productive hydrocarbon bearing formation or experience mechanical difficulties while drilling or completing the well, resulting in a reduction in production from the well or abandonment of the well. If we drill additional wells that we identify as dry holes in our current and future drilling locations, our drilling success rate may decline and materially harm our business. We cannot assure you that the analogies we draw from available data from other wells, more fully explored locations or producing fields will be applicable to our drilling locations. Further, initial production rates reported by us or other operators may not be indicative of future or long-term production rates. In sum, the cost of drilling, completing and operating any well is often uncertain, and new wells may not be productive.

Our potential drilling location inventories are scheduled to be developed over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling. In addition, we may not be able to raise the substantial amount of capital that would be necessary to drill a substantial portion of our potential drilling locations.

Our management has identified and scheduled drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. As of December 31, 2011, only 400 gross (287 net) of our approximately 1,200 identified potential future gross drilling locations were attributed to proved undeveloped reserves. These potential drilling locations, including those without proved undeveloped reserves, represent a significant part of our growth strategy. Our ability to drill and develop these locations is subject to a number of uncertainties, including the availability of capital, seasonal conditions, regulatory approvals, oil and natural gas prices, costs and drilling results. Because of these uncertainties, we do not know if the numerous potential drilling locations we have identified will ever be drilled or if we will be able to produce oil or natural gas from these or any other potential drilling locations. Pursuant to existing SEC rules and guidance, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking. These rules and guidance may limit our potential to book additional proved undeveloped reserves as we pursue our drilling program.

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, 2011, all of our acreage in Arkansas was held by production and not subject to lease expiration. As of December 31, 2011, 32,820 net acres of our properties in the Rocky

Mountain region, specifically 8,000 acres in the Wattenberg Field and 24,820 acres in the North Park Basin, were not held by production. For these properties, if production in paying quantities is not established on units containing these leases during the next three years, then 2,119 net acres will expire in 2012, 11,453 net acres will expire in 2013 and 36 net acres will expire in 2014. 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.

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.

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

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

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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, the federal government is studying any environmental risk with respect to hydraulic fracturing and evaluating whether to restrict its use. Legislation has been introduced in the United States Congress that would amend the federal Safe Drinking Water Act ("SDWA") to eliminate an existing exemption for certain 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, such 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 hydraulic fracturing. Scrutiny of hydraulic fracturing activities continues in other ways, with the EPA having commenced a multi-year study of the potential environmental impacts of hydraulic fracturing, the initial results of which are anticipated to be available by late 2012. In addition, on October 21, 2011, the EPA announced its intention to propose regulations by 2014 under the federal Clean Water Act to regulate wastewater discharges from hydraulic fracturing and other natural gas production. The U.S. Department of the Interior has also announced its intention to propose a new rule regulating hydraulic fracturing activities on federal lands, including requirements for disclosure, well bore integrity and handling of flowback water, which, if adopted, would affect our operations on federal lands. In addition to these federal initiatives, several state and local governments have moved to require disclosure of fracturing fluid components or otherwise to regulate their use more closely, including states in which we operate (Colorado, California and Arkansas). In certain areas of the country, new drilling permits for hydraulic fracturing have been

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put on hold pending development of additional standards. The adoption of any future federal, state or local laws or implementing regulations imposing permitting or reporting obligations on, or otherwise limiting, the hydraulic fracturing process could make it more difficult and more expensive to complete oil and natural gas wells in low-permeability formations and increase our costs of compliance and doing business, as well as delay or prevent the development of unconventional gas resources from shale formations which are not commercial without the use of hydraulic fracturing.

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

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

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

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

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

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

Competition in the oil and natural gas industry is intense, making it more difficult for us to acquire properties, market oil and natural gas and secure trained personnel.

Our ability to acquire additional drilling locations and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment for acquiring properties, marketing oil and natural gas and securing equipment and trained personnel. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours. Those companies may be able to pay more for productive oil and natural gas properties and exploratory drilling locations or to identify, evaluate, bid for and purchase a greater number of properties and locations than our financial or personnel resources permit. Furthermore, these companies may also be better able to withstand the financial pressures of unsuccessful drilling attempts, sustained periods of volatility in financial markets and generally adverse global and industry-wide economic conditions, and may be better able to absorb the burdens resulting from changes in relevant laws and regulations, which would adversely affect our competitive position. In addition, companies may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. The cost to attract and retain qualified personnel has increased over the past few years due to competition and may increase substantially in the future. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital, which could have a material adverse effect on our business.

The loss of senior management or technical personnel could adversely affect our operations.

To a large extent, we depend on the services of our senior management and technical personnel. The loss of the services of our senior management or technical personnel, including Michael R. Starzer, our President and Chief Executive Officer or any of the Executive Vice Presidents of the Company, could have a material adverse effect on our operations. We do not maintain, nor do we plan to obtain, any insurance against the loss of any of these individuals.

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We recorded substantial compensation expense in the fourth quarter of 2011 and we are likely to 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 vested upon consummation of our IPO, we incurred compensation expense in the fourth quarter of 2011 in the amount of $4.4 million. In addition, our compensation expenses may increase in the future as compared to our historical expenses because of the costs associated with our 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 restricted stock awards and stock options generally over the vesting period of awards made to recipients.

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 for a portion of our oil and natural gas production, including collars and fixed-price swaps. We have not designated any of our derivative instruments as hedges for accounting purposes and record all derivative instruments on our balance sheet at fair value. Changes in the fair value of our derivative instruments are recognized in earnings. Accordingly, our earnings may fluctuate significantly as a result of changes in the fair value of our derivative instruments.

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

- production is less than the volume covered by the derivative instruments;
- the counterparty to the derivative instrument defaults on its contract 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 and may expose us to cash margin requirements.

Current or proposed financial legislation and rulemaking 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 Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act"), which was signed into law on July 21, 2010, establishes, among other provisions, federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. The Commodities Futures Trading Commission (the "CFTC") is required to implement rules relating to these activities by July 16, 2012. On October 18, 2011, the CFTC approved regulations to set position limits for certain futures and option contracts in the major energy markets, which regulations are presently being challenged in federal court by the Securities Industry Financial Markets Association and the International Swaps and Derivatives Association. The Dodd-Frank Act may also require us to comply with margin requirements and with certain clearing and trade execution requirements in our derivative activities, although 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 separate entities, which may not be as creditworthy as the current counterparties.

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The Dodd-Frank Act 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 our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the Dodd-Frank Act 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 Dodd-Frank Act was intended, in part, to reduce the volatility of oil and gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and gas. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on our consolidated financial position, results of operations and cash flows.

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, increases in interest rates or a reduction in credit rating. 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. Recent and 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.

We may not be able to generate enough cash flow to meet our debt obligations.

We expect our earnings and cash flow to vary significantly from year to year due to the nature of our industry. As a result, the amount of debt that we can manage in some periods may not be appropriate for us in other periods. Additionally, our future cash flow may be insufficient to meet our debt obligations and other commitments. Any insufficiency could negatively impact our business. A range of economic, competitive, business and industry factors will affect our future financial performance, and, as a result, our ability to generate cash flow from operations and to pay our debt obligations. Many of these factors, such as oil and natural gas prices, economic and financial conditions in our industry and the global economy and initiatives of our competitors, are beyond our control. If we do not generate enough cash flow from operations to satisfy our debt obligations, we may have to undertake alternative financing plans, such as:

- selling assets;
- reducing or delaying capital investments;
- seeking to raise additional capital; or
- refinancing or restructuring our debt.

If for any reason we are unable to meet our debt service and repayment obligations, we would be in default under the terms of the agreements governing our debt, which would allow our creditors at that time to declare all outstanding indebtedness to be due and payable, which would in turn trigger cross-acceleration or cross-default rights between the relevant agreements. In addition, our lenders could compel us to apply all of our available cash to repay our borrowings. If amounts outstanding under our revolving credit facility were to be accelerated, we cannot be certain that our assets would be sufficient to repay in full the money owed to the lenders or to our other debt holders. Please see

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"Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and capital resources."

Our revolving credit facility contains operating and financial restrictions that may restrict our business and financing activities.

Our revolving credit facility contains a number of restrictive covenants that will impose significant operating and financial restrictions on us, including restrictions on our ability to, among other things:

- sell assets;
- pay distributions on, redeem or repurchase our common stock
- make investments;
- incur or guarantee additional indebtedness or issue preferred stock;
- create or incur certain liens;
- make certain acquisitions and investments;
- consolidate, merge or transfer all or substantially all of our assets;
- engage in transactions with affiliates;
- create unrestricted subsidiaries;
- engage in certain business activities.

As a result of these covenants, we will be limited in the manner in which we conduct our business, and we may be unable to engage in favorable business activities or finance future operations or capital needs.

Our level of indebtedness may increase and reduce our financial flexibility.

As of December 31, 2011, we had $6.6 million of indebtedness outstanding under our revolving credit facility, and $213.4 million available for future secured borrowings under our revolving credit facility. We intend to fund our capital expenditures through our cash flow from operations and borrowings under our credit facility.

Our level of indebtedness could affect our operations in several ways, including the following:

- a significant portion of our cash flows could be used to service our indebtedness;
- a high level of debt would increase our vulnerability to general adverse economic and industry conditions;

the covenants contained in the agreements governing our outstanding indebtedness will limit our ability to borrow additional funds, dispose of assets, pay dividends and make certain investments;

a high level of debt may place us at a competitive disadvantage compared to our competitors that are less leveraged and therefore, may be able to take advantage of opportunities that our indebtedness would prevent us from pursuing;

our debt covenants may also affect our flexibility in planning for, and reacting to, changes in the economy and in our industry;

a high level of debt may make it more likely that a reduction in our borrowing base following a periodic redetermination could require us to repay a portion of our then-outstanding bank borrowings; and

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.

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A high level of indebtedness increases the risk that we may default on our debt obligations. Our ability to meet our debt obligations and to reduce our level of indebtedness depends on our future performance. General economic conditions, oil and natural gas prices and financial, business and other factors affect our operations and our future performance. Many of these factors are beyond our control. We may not be able to generate sufficient cash flows to pay the interest on our debt and future working capital, borrowings or equity financing may not be available to pay or refinance such debt. Factors that will affect our ability to raise cash through an offering of our capital stock or a refinancing of our debt include financial market conditions, the value of our assets and our performance at the time we need capital.

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 at least semi-annually, and the lenders holding $66^2/_3$% of the aggregate commitments or we may request one additional redetermination in each six-month period. 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 requiring us to negotiate renewals, arrange new financing or sell significant assets, all of which could have a material adverse effect on our business and financial results.

The inability of one or more of our customers to meet their obligations to us may adversely affect our financial results.

Our principal exposures to credit risk are through receivables resulting from the sale of our oil and natural gas production ($17.9 million in receivables at December 31, 2011), which we market to energy marketing companies, refineries and affiliates.

We are subject to credit risk due to the concentration of our oil and natural gas receivables with several significant customers. This concentration of customers may impact our overall credit risk since these entities may be similarly affected by changes in economic and other conditions. For the year ended December 31, 2011, sales to Lion Oil Trading & Transport and Plains Marketing accounted for approximately 35% and 45%, respectively, of our total sales. For the year ended December 31, 2010, sales to Lion Oil Trading & Transport and Plains Marketing accounted for approximately 52% and 30%, respectively, of our total sales. We do not require our customers to post collateral. 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.

Failure to archive and maintain effective internal control over financial reporting in accordance with rules of the SEC could harm our business and operating results and/or result in a loss of investor confidence in our financial reports, which could in turn have a material adverse effect on our business and stock price.

Under current SEC rules, we will be required to issue a report assessing the effectiveness of our internal controls over financial reporting as of December 31, 2012, and on an annual basis thereafter, pursuant to Section 404 of the Sarbanes-Oxley Act. This assessment will require us to document, assess and test our internal controls over financial reporting more comprehensively than we do currently. In addition, our outside auditors will be required to audit and report on our internal controls. We are currently on task to be compliant with Section 404 at the Entity Level Control Level and will

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commence our work at the Activity Control Level during the second quarter 2012 to ensure compliance by the SEC rules deadline of December 31, 2012.

To complete our assessment, we will be required to enhance the documentation of our policies, procedures and internal controls over financial reporting, assess the effectiveness of the design of those controls and test whether those controls are operating as designed. This process, which we are currently conducting, involves considerable time and expense. During the course of our assessment, we may identify material weaknesses that we will attempt to remediate in time to meet the deadline imposed by SEC rules for certification of our internal controls. Our ability to report results in a timely, complete and accurate manner will provide all parties with the Company's financial position and the disclosure of material events. The efforts we have undertaken, or will undertake, to address any issues, that may arise or be discovered in the future will be designed to ensure our compliance. We have taken actions to adopt more extensive accounting controls and financial review procedures and hired additional accounting and information technology staff. Prior to 2012, we had outsourced these functions to third party vendors.

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 have begun to incur significant additional costs and expenses and our compliance with these requirements requires a substantial amount of management's time.

As a public company with listed equity securities, we need to comply with 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 NYSE, with which we were not required to comply as a private company for most of 2011. Complying with these statutes, regulations and requirements occupies a significant amount of time of our board of directors and management and will continue to significantly increase our costs and expenses.

In addition, being a public company subject to these rules and regulations has increased 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.

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

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

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Risks Relating to our Common Stock

We do not intend to pay, and we are currently prohibited from paying, dividends on our common stock and, consequently, our shareholders' only opportunity to achieve a return on their 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 revolving credit facility. Consequently, our shareholders' only opportunity to achieve a return on their investment in us will be if the market price of our common stock appreciates, which may not occur, and the shareholder sells their shares at a profit. There is no guarantee that the price of our common stock will ever exceed the price that the shareholder paid.

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 our current stockholders' 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. Black Bear, a fund advised by West Face Capital, and certain clients of AIMCo own 21,166,134 shares, or approximately 53.6% of our total outstanding shares. Each of West Face Capital and certain clients of AIMCo is a party to a registration rights agreement with us. Pursuant to this agreement, subject to the terms of the lock-up agreement between such parties and the underwriters of our IPO, we have agreed to effect the registration of shares held by Black Bear, a fund advised by West Face Capital, and certain clients of AIMCo if they so request or if we conduct other offerings of our common stock. In addition, in connection with our IPO, we filed 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 long term incentive plan. Shares registered under this registration statement on Form S-8 and issued to our employees in the future will be available for sale in the open market after any vesting or other restrictions lapse.

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.

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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.

Our certificate of incorporation and bylaws contain, and Delaware law contains, provisions that could enable our management to resist a takeover attempt. Among other things, our certificate of incorporation and bylaws:

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

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

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

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

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

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

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

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

These provisions could:

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

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

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

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

West Face Capital and AIMCo together may be deemed to beneficially own, control or have substantial influence over approximately 53.6% of our outstanding common stock. 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 an 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 substantially influence the outcome of stockholder votes. Even if the investment management agreement between West Face Capital 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. The investment management agreement with AIMCo may be terminated upon 90 days prior written notice or immediately in certain circumstances.

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

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

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

The significant ownership interest of Black Bear, a fund advised by West Face Capital, and certain clients of AIMCo could also adversely affect investors' perceptions of our corporate governance. Further, because of the voting control exercised by West Face Capital, we are considered a "controlled company" for purposes of the NYSE listing requirements. Although we do not currently intend to rely upon the exemptions to the NYSE's independence standards available for controlled companies, we may choose to do so in the future to the extent we remain a controlled company.

Item 1B. *Unresolved Staff Comments.*

None.

Item 2. *Properties.*

The information required by Item 2. is contained in Item 1. Business and incorporated herein by reference.

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Item 3. ***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 filing, there are no material pending or overtly threatened legal actions against us that we are aware of.

In June 2011, Frank H. Bennett, a co-manager of Bonanza Creek Oil Company ("BCOC"), BCEC's predecessor, and former chairman of BCEC, made a demand against Michael R. Starzer, our President and Chief Executive Officer, focusing on Mr. Starzer's handling of the operation, accounting and finances of BCOC and BCEC primarily during the 2005-2006 period. Mr. Bennett's demands do not allege any wrongdoing by or claims against Bonanza Creek Energy, Inc. This matter was sent to arbitration in July 2011. There can be no assurance as to the ultimate outcome of the arbitration proceedings.

In July 2011, our board of directors formed a Special Litigation Committee comprised of three non-executive directors to conduct an investigation of the allegations. The Special Litigation Committee retained outside independent advisors and conducted an in-depth investigation. The Special Litigation Committee concluded that neither it nor its legal or financial advisors had found any evidence to support any of Mr. Bennett's allegations. Our board of directors concluded that the allegations against Mr. Starzer are unsubstantiated and lack merit. However, there can be no assurance as to the ultimate outcome of the arbitration proceedings. The parties are currently conducting discovery. The arbitration hearing is scheduled to commence in July 2012.

Item 4. ***Mine Safety Disclosures.***

Not applicable.

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PART II

Item 5. *Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.*

Market for Registrant's Common Equity. Our common stock is listed on the New York Stock Exchange ("NYSE") under the symbol "BCEI".

The following table sets forth the range of high and low sales prices of our common stock as reported by the NYSE:

	High	Low
4th Quarter 2011 (from December 15, 2011)[1]	$ 15.50	$ 12.39
1st Quarter 2012 (through March 15, 2012)	$ 20.15	$ 13.09

(1) Represents the period from December 15, 2011, the date on which our common stock began trading on the NYSE, through December 31, 2011.

Holders. As of March 15, 2012, there were approximately 82 registered holders of our common stock.

Dividends. We have not paid any cash dividends since our inception. Covenants contained in our revolving credit facility restricts the payment of cash dividends on our common stock. We currently intend to retain all future earnings for the development and growth of our business, and we do not anticipate declaring or paying any cash dividends to holders of our common stock in the foreseeable future.

On March 15, 2012, the last sale price of our common stock, as reported on the NYSE, was $19.14 per share.

Repurchase of Equity Securities. Neither we nor any "affiliated purchaser" repurchased any of our equity securities in the quarter ended December 31, 2011.

Use of Proceeds. On December 14, 2011, our registration statement on Form S-1 (File No. 333-174765) was declared effective for our IPO pursuant to which we sold 10 million shares of our common stock at a public offering price of $17.00 per share for an aggregate offering price of $170 million. Morgan Stanley & Co. LLC and Credit Suisse Securities (USA) LLC served as joint book-running managers for the offering, and Raymond James & Associates, Inc., RBC Capital Markets, LLC, BMO Capital Markets Corp., Howard Weil Incorporated, KeyBanc Capital Markets Inc., Stifel, Nicolaus & Company, Incorporated, BNP Paribas Securities Corp. and SG Americas Securities, LLC served as co-managers.

As a result of our IPO, we received net proceeds of $155.9 million, after deducting underwriting discounts and commissions and other offering expenses. None of the expenses associated with our IPO were paid to directors, officers or persons owning ten percent or more of our common stock or to their associates, or to our affiliates. As of December 31, 2011, we had used approximately $155 million of those proceeds for the repayment of indebtedness. There has been no material change in the planned use of proceeds from our initial public offering as described in our final prospectus filed with the SEC pursuant to Rule 424(b) on December 19, 2011.

Stock Performance Graph. This performance graph shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), or otherwise subject to liabilities under that section and shall not be deemed to be incorporated by reference into any filing of Bonanza Creek Energy, Inc. under the Securities Act of 1933, as amended, or the Exchange Act, except as shall be expressly set forth by specific reference in such filing.

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The following graph compares, for the 16 day period ended December 31, 2011, the cumulative total stockholder return for Bonanza Creek Energy, Inc.'s common stock, the Standard and Poor's 500 Stock Index (the "S&P 500 Index") and the Standard and Poor's 500 Oil & Gas Exploration & Production Index ("S&P O&G E&P Index"). The measurement points in the graph below are December 15, 2011 (the first trading day of our common stock on the New York Stock Exchange) and the last trading day of the fiscal year ended December 31, 2011. The graph assumes that $100 was invested on December 15, 2011 in the common stock of Bonanza Creek Energy, Inc., the S&P 500 Index and the S&P O&G E&P Index and assumes reinvestment of any dividends. The stock price performance on the following graph is not necessarily indicative of future stock price performance.

Item 6. *Selected 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 statements of operations data for the years ended December 31, 2007 and 2008 are derived from audited consolidated financial statements of BCEC not included in this Annual Report on Form 10-K. The consolidated audited financial statements of BCEC for the periods not included in this annual report on Form 10-K were previously filed in BCEI's Form S-1 (File No. 333-174765). The consolidated statement of operations data for the years ended December 31, 2009 and the period ended December 23, 2010 are derived from the audited consolidated financial statements of BCEC included elsewhere in this Annual Report on Form 10-K. The consolidated statement of operations data for the eight day period ended December 31, 2010 and year ended December 31, 2011 are derived from the audited consolidated financial statements of BCEI included elsewhere in this Annual Report on Form 10-K. The consolidated balance sheets data as of December 31, 2007, 2008 and 2009 are derived from the audited consolidated financial statements of BCEC, which are not included in this Annual Report on From 10-K. The consolidated audited financial statements of BCEC for the periods not included in this annual report on Form 10-K were previously filed in BCEI's Form S-1 (File No. 333-174765). The consolidated balance sheet data as of December 31, 2010 and 2011 is derived from our audited consolidated financial statements of BCEI included elsewhere in this Annual Report on Form 10-K. In management's opinion, the financial statements 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 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

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financial statements and the notes to those financial statements included elsewhere in this Annual Report on Form 10-K.

	Bonanza Creek Energy Company, LLC (Predecessor)				Bonanza Creek Energy, Inc.		
	2007	2008	2009	Period Ended December 23, 2010[1]	Period from Inception (December 23, 2010) to December 31, 2010	Year Ended December 31, 2011	Bonanza Creek Energy, Inc. Pro Forma 2010[2] (unaudited)
	(in thousands, except per share data)						
Statement of Operations Data:							
Revenues:							
Oil sales	$ 11,427	$ 39,967	$ 27,601	$ 34,431	$ 1,325	$ 86,301	$ 45,413
Natural gas sales	1,736	5,165	3,671	6,226	207	13,449	10,253
Natural gas liquids and CO_2 sales	821	2,782	3,169	7,672	213	12,713	8,365
Total revenues	13,984	47,914	34,441	48,329	1,745	112,463	64,031
Operating expenses:							
Lease operating	4,037	20,434	13,449	14,792	483	21,488	17,285
Severance and ad valorem taxes	577	1,847	2,148	1,621	70	6,088	2,524
Depreciation, depletion and amortization	4,237	25,463	14,108	14,225	506	31,508	20,917
General and administrative	4,752	7,477	7,610	8,375	323	13,164	9,338
Employee stock compensation[3]						4,449	
Exploration	65	25	131	361		884	380
Impairment of oil and gas properties[4]		26,437	579			4,067	
Cancelled private placement[5]				2,378			2,378
Total operating expenses	13,668	81,683	38,025	41,752	1,382	81,648	52,822
Income (loss) from operations	316	(33,769)	(3,584)	6,577	363	30,815	11,209
Other income (expense):							
Interest expense	(5,748)	(12,870)	(16,582)	(18,001)	(58)	(4,017)	(1,263)
Amortization of debt discount	(1,684)	(5,987)	(7,963)	(8,862)			
Write off of deferred financing costs				(1,663)			(1,663)
Gain on sale of oil and gas properties		8	303	4,055			4,055
Unrealized gain (loss) in fair value of warrant put option[6]	(32,302)	70,972	(80,640)	34,345			
Unrealized gain (loss) in fair value of commodity derivatives	(925)	48,716	(34,589)	(7,605)	(514)	225	(8,119)
Realized gain (loss) on settled commodity derivatives	26	1,913	13,451	5,919	(47)	(3,024)	5,872
Other income (loss)	(43)	(229)	(179)	19		(110)	(47)
Total other income (expense)	(40,676)	102,523	(126,199)	8,207	(619)	(6,926)	(1,165)
Income (loss) before income taxes	(40,360)	68,754	(129,783)	14,784	(256)	23,889	10,044
Income tax benefit (expense)[7]					94	(11,198)	(3,696)
Net income (loss)	$ (40,360)	$ 68,754	$ (129,783)	$ 14,784	$ (162)	$ 12,691	$ 6,348
Net income (loss) per common share[8]							
Basic					$	$ 0.43	$ 0.22
Diluted					$	$ 0.43	$ 0.22
Weighted average shares outstanding							
Basic					29,123	29,576	29,123

Diluted	29,123	29,576	29,123

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

(2) The pro forma information above gives effect to our Corporate Restructuring as if it had occurred on January 1, 2010. See " Unaudited Pro Forma Financial Data."

(3) In connection with our IPO, the Company distributed 243,945 fully vested shares of common stock previously held in trust to our employees and recorded a $4.1 million stock compensation charge. In addition, the Company distributed the remaining 3,400 shares of our former Class B common stock to our employees. In connection with our IPO, all issued and outstanding shares of our former Class B Common Stock converted into 437,787 shares of restricted common stock, vesting over a three year period and we recorded a $0.1 million stock compensation charge. We expect to recognize employee stock compensation expense relating to these grants during the years ended December 31, 2012, 2013, and 2014 of approximately $2.5 million, $2.5 million, and $2.3 million, respectively, assuming no forfeitures.

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(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 natural gas prices. The impairment for 2011 was related to steam flooding results in our legacy California assets that were lower than expected and the impairment of one non-core field in Southern Arkansas was related to the loss of a lease.

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

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

(7) Our predecessor, BCEC, was a partnership for federal income tax purposes and, therefore, was not subject to entity-level taxation. Our pro forma results reflect our taxation as a subchapter "C" 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 December 31,	
	2007	2008	2009	2010	2011
	(in thousands)				
Balance Sheet Data:					
Cash and cash equivalents	$	$ 4,088	$ 2,522	$	$ 2,090
Property and equipment, net	89,646	195,280	188,367	496,582	628,125
Total assets	97,044	241,625	211,552	516,104	664,349
Long term debt, including current portion:					
Credit facility	27,274	107,000	99,000	55,400	6,600
Senior subordinated notes, net of discount	51,561	75,499	92,442		
Second lien term loan(1)					
Subordinated unsecured note		10,000	10,799		
Warrant put options(2)	42,851	828	81,468		
Total members'/stockholders' equity (deficit)	(33,566)	35,988	(93,795)	356,380	527,982

	Bonanza Creek Energy Company, LLC (Predecessor)				Bonanza Creek Energy, Inc.	
	Year Ended December 31,			Period Ended December 23, 2010(3)	Period from Inception (December 23, 2010) to December 31, 2010	Year Ended December 31, 2011
	2007	2008	2009			
	(in thousands)					
Other Financial Data:						
Net cash provided by (used in) operating activities	$ (561)	$ 11,128	$ 11,134	$ 22,759	$ (1,633)	$ 57,603
Net cash provided by (used in) investing activities	(43,265)	(79,581)	(7,185)	(32,127)	(817)	(158,902)
Net cash provided by (used in) financing activities	38,787	72,541	(5,515)	9,297		103,389

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

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

(3)

We completed our Corporate Restructuring on December 23, 2010.

Unaudited Pro Forma Financial Information

We completed our Corporate Restructuring on December 23, 2010. 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 Annual Report on Form 10-K. The unaudited pro forma statement of operations for the year ended December 31, 2010 was prepared as if our Corporate Restructuring had occurred at January 1, 2010.

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

The following unaudited pro forma financial statements do not purport to represent what our actual results of operations would have been if this acquisition had occurred on January 1, 2010. The unaudited pro forma financial statements should be read in conjunction with our historical financial statements and related notes for the periods presented included elsewhere in this Annual Report on Form 10-K.

	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	Bonanza Creek Energy, Inc. Year Ended December 31, 2010
				(unaudited)	(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

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

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

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

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

Pro Forma Reserve Quantity and Standardized Measure Information

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

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

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Changes in estimated reserve quantities:

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

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

Standardized Measure from estimated production of proved oil and gas reserves as of December 23, 2010 (in thousands):

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

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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 from proved oil and gas reserves (in thousands):

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

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

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

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Item 7. ***Management's Discussion and Analysis of Financial Condition and Results of Operations***

Year Ended December 31, 2011 Compared to Period Ended December 23, 2010

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

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 Annual Report on Form 10-K. Comparative results of operations for the period indicated are discussed below.

Year Ended December 31, 2011 Compared to Period Ended December 23, 2010

Revenues

	Period Ended December 23, 2010	Year Ended December 31, 2011	Change	Percent Change
	(In thousands, except percentages)			
Revenues:				
Crude oil sales	$ 34,431	$ 86,301	$ 51,870	151%
Natural gas sales	6,226	13,449	7,223	116%
Natural gas liquids sales	7,088	12,357	5,269	74%
CO_2 sales	583	356	(227)	(39)%
Product revenues	$ 48,328	$ 112,463	$ 64,135	133%

	Period Ended December 23, 2010	Year Ended December 31, 2011	Change	Percent Change
Sales volumes:				
Crude oil (MBbls)	469.0	953.0	484.0	103%
Natural gas (MMcf)	1,308.5	2,776.4	1,467.9	112%
Natural gas liquids (MBbls)	126.5	183.8	57.3	45%
Crude oil equivalent (MBoe)[1]	813.6	1,599.5	785.9	97%

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

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	Period Ended December 23, 2010	Year Ended December 31, 2011	Change	Percent Change
Average Sales Prices (before hedging)[1]:				
Crude oil (per Bbl)	$ 73.41	$ 90.56	$ 17.15	23%
Natural gas (per Mcf)	4.76	4.84	0.08	1.7%
Natural gas liquids (per Bbl)	56.04	67.23	11.19	20%
Crude oil equivalent (per Boe)[2]	58.69	70.09	11.40	19%

	Period Ended December 23, 2010	Year Ended December 2011	Change	Percent Change
Average Sales Prices (after hedging)[1]:				
Crude oil (per Bbl)	$ 75.07	$ 86.69	$ 11.62	15%
Natural gas (per Mcf)	5.01	5.09	0.08	1.6%
Natural gas liquids (per Bbl)	56.04	67.23	11.19	20%
Crude oil equivalent (per Boe)[2]	60.05	68.20	8.15	14%

(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 133% to $112.5 million for the year ended December 31, 2011 compared to $48.3 million for the period ended December 23, 2010. Oil production increased 103% and natural gas production increased 112% during the year ended December 31, 2011 as compared to the period ended December 23, 2010. The most significant components of the increased production was related to an increased drilling program and the acquisition of HEC, which occurred on December 23, 2010. Our product revenues and production for the period ended December 23, 2010 excluded HEC revenues and production of $14.0 million and 268.2 Mboe, respectively. The increase in net revenues was also the result of a 23% increase in oil prices with a 1.7% increase in natural gas prices, respectively, for an overall increase of 19% per Boe. Also contributing to the increased revenue was a 97% increase in production attributable to our drilling program. During 2011, we drilled and completed approximately 100 wells as compared to 42 wells during 2010.

Operating Expenses

	Period Ended December 23, 2010	Year Ended December 31, 2011	Change	Percent Change
	(In thousands, except percentages)			
Expenses:				
Lease operating	$ 14,792	$ 21,488	$ 6,696	45%
Severance and ad valorem taxes	1,620	6,088	4,468	276%
General and administrative	8,375	17,613	9,238	110%
Depreciation, depletion and amortization	14,225	31,508	17,283	121%
Exploration	361	884	523	145%
Impairment of oil and gas properties		4,067	4,067	100%
Cancelled private placement	2,378		(2,378)	(100)%
Operating expenses	$ 41,751	$ 81,648	$ 39,897	96%

	Period Ended December 23, 2010	Year Ended December 31, 2011	Change	Percent Change
Selected Costs ($ per Boe):				
Lease operating	$ 18.18	$ 13.43	$ (4.75)	(26)%
Severance and ad valorem taxes	1.99	3.81	1.82	91%
General and administrative	10.30	11.01	0.71	7%
Depreciation, depletion and amortization	17.49	19.70	2.21	14%
Exploration	0.44	0.55	0.11	25%
Impairment of oil and gas properties		2.54	2.54	100%
Cancelled private placement	2.92		(2.92)	(100)%
Operating expenses	$ 51.32	$ 51.04	$ (0.28)	(0.5)%

Lease operating expenses. Our lease operating expenses increased $6.7 million, or 45%, to $21.5 million for the year ended December 31, 2011 from $14.8 million for the period ended December 23, 2010 and decreased on an equivalent basis from $18.18 per Boe to $13.43 per Boe. The increase in lease operating expense was related to increased production volumes due to the acquisition of HEC on December 23, 2010 and increased production attributable to our drilling program. The period ended December 23, 2010 does not include HEC lease operating expenses, which were $2.0 million. During the year ended December 31, 2011, gauging and pumping, compressor rentals, well servicing and testing, and gas plant maintenance and repairs were $1.8 million, $1.0 million, $1.0 million and $0.8 million higher, respectively, than the period ended December 23, 2010. The decrease in lease operating expenses on an equivalent basis was primarily related to the lower operating costs of the wells acquired from HEC. On an equivalent basis, the lease operating expense for the wells acquired from HEC was $7.50 per Boe during the period ended December 23, 2010 as compared to the lease operating expense for BCEC's wells which was $18.18 per Boe during the period ended December 23, 2010.

Severance and ad valorem taxes. Our severance and ad valorem taxes increased $4.5 million, or 276%, to $6.1 million for the year ended December 31, 2011 from $1.6 million for the period ended December 23, 2010 and increased on a Boe basis from $1.99 to $3.81. The increase was primarily related to a 97% increase in production volumes and a 19% increase in realized prices per Boe during the year ended December 31, 2011 as compared to the period ended December 23, 2010, and an increase in ad valorem tax of $2.4 million due to higher assessment values. The period ended December 23, 2010 does not include HEC severance and ad valorem tax, which were $0.8 million. The increase in severance and ad valorem taxes on a Boe basis for the year ended December 31, 2011 as compared to the period ended December 23, 2010 was primarily related to higher ad valorem taxes of $2.4 million and true-ups of estimated severance taxes based on Colorado severance tax returns for 2009 and 2010 that were filed during April of the subsequent year. The revision of estimated severance taxes based on the final Colorado severance tax returns resulted in a decrease in severance tax expense in 2010 and an increase in severance tax expense in 2011.

General and administrative. Our general and administrative expense increased $9.2 million, or 110%, to $17.6 million for the year ended December 31, 2011 from $8.4 million for the period ended December 23, 2010. The period ended December 23, 2010 does not include HEC's general and administrative expenses, which were $0.6 million. During the year ended December 31, 2011 wages and benefits and legal and professional services fees were $2.1 million and $2.0 million, respectively, higher than the previous period. The increase in wages and benefits is related to increased head count and $1.1 million of the increase in legal and professional services fees were related to investigations and transactions not consummated. In connection with our IPO, the Company distributed 243,945 fully vested shares of common stock previously held in trust to our employees and recorded a $4.1 million stock compensation charge. In addition, the Company distributed the remaining 3,400 shares of our former Class B common stock to our employees. In connection with our IPO, all issued and outstanding shares of our former Class B Common Stock converted into 437,787 shares of restricted common stock, vesting over a three year period and we recorded a $0.1 million stock compensation charge. We expect to recognize employee stock compensation expense relating to these grants during the years ended December 31, 2012, 2013, and 2014 of approximately $2.5 million, $2.5 million, and $2.3 million, respectively, assuming no forfeitures.

Depreciation, depletion and amortization. Our depreciation, depletion and amortization expense increased $17.3 million, or 121%, to $31.5 million for the year ended December 31, 2011 from $14.2 million for the period ended December 23, 2010. This increase was the result of a 97% increase in production and the step up in basis that was recorded in oil and gas properties as a result of our Corporate Restructuring. In connection with our Corporate Restructuring, all of our oil and gas fields were adjusted to fair value based on each field's discounted future net cash flows, which resulted in basis increases to the Mid-Continent and Rocky Mountain fields with corresponding decreases to the California fields. Our depreciation, depletion and amortization expense per Boe increased by $2.21, or 14%, to $19.70 for the year ended December 23, 2011 as compared to $17.49 for the period ended December 23, 2010.

Exploration. Our exploration expense increased $0.5 million, or 145%, to $0.9 million for the year ended December 31, 2011 from $0.4 million in the period ended December 23, 2010. The increase in exploration expense was primarily related to the acquisition of 7,700 acres of 3-D seismic data on the eastern edge of the Wattenberg field in Weld County, Colorado to help evaluate our Niobrara oil shale acreage.

Impairment of Proved Properties. The Company recorded $3.5 million of proved property impairments on the Company's legacy California assets and $0.6 million of proved property impairment in one non-core field in Southern Arkansas for the year ended December 31, 2011. The impairments of the Company's legacy assets in California were related to steam flooding results that were lower than expected and the impairment of the non-core field in Southern Arkansas was related to the loss of a lease. There were no impairments of proved properties for the period ended December 23, 2010.

Other Income and Expense

Interest expense. Our interest expense decreased $14.0 million, or 78%, to $4.0 million for the year ended December 31, 2011 from $18.0 million for the period ended December 23, 2010. The decrease resulted from the application of $182 million of cash proceeds from our Corporate Restructuring to repay the second lien term loan, the senior subordinated notes and a related party note payable, and to repay $29 million of principal under our credit facility on December 23, 2010. Average debt outstanding for the year ended December 31, 2011 was $95.3 million as compared to $215.3 million for the period ended December 23, 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 year ended December 31, 2011 from $4.1 million in the period ended December 23, 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 $8.9 million from a gain of $5.9 million for the period ended December 23, 2010 to a loss of $3.0 million for the year ended December 31, 2011. Because we assumed a derivative in a liability position in 2008, our realized gain was higher by $4.8 million upon the settlement of this portion of the assumed derivative in the period ended December 23, 2010. The decrease from a realized cash hedge gain to a loss period over period was primarily related to commodity prices that

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were 19% higher during the year ended December 31, 2011 as compared to the period ended December 23, 2010.

Income Tax Expense. Our predecessor, BCEC, was not subject to federal and state income taxes. As a result of our Corporate Restructuring, we were organized as a Delaware corporation subject to federal and state income taxes. During the year ended December 31, 2011, the estimated effective tax rate was revised to reflect significant capital expenditures in Arkansas and the effective tax rate increased from 36.87% to 37.98%. The increase in the effective tax rate was applied to the January 1, 2011 deferred income tax liability resulting in an increase to the net deferred tax liability and deferred income tax expense of $2.1 million with an additional $9.1 million incurred for federal and state income taxes for the year ended December 31, 2011 for a total deferred income tax expense in our consolidated statement of operations of $11.2 million. We are allowed to deduct various items for tax reporting purposes that are capitalized for purposes of financial statement presentation. All income taxes for the year ended December 31, 2011 were deferred.

Change in fair value of warrant put option. The fair value of the warrant put option decreased $34.3 million, or 100%, to $0 for the year ended December 31, 2011 from a gain of $34.3 million for the period ended December 23, 2010. The decrease resulted from the exercise of the warrants on December 23, 2010 in connection with our Corporate Restructuring.

Amortization of debt discount. Our expense for amortization of debt discount decreased $8.9 million, or 100%, to $0 for the year ended December 31, 2011 from $8.9 million for the period ended December 23, 2010. The decrease resulted from the retirement of BCEC's senior subordinated notes on December 23, 2010 in connection with our Corporate Restructuring.

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

Revenues

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

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

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

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	Year Ended December 31, 2009	Period Ended December 23, 2010	Change	Percent Change
Average Sales Prices (before hedging)[1]:				