Bill Barrett Corporation

2014 Annual Report

TRANSITION TO OIL-FOCUSED PORTFOLIO IS COMPLETE

Fellow Shareholders

R. Scot Woodall
Chief Executive Officer
and President

In 2014, we executed on two transformational strategic objectives. First, we successfully completed our multi-year endeavor to transition our portfolio to concentrate on two core oil development assets in the Denver-Julesburg ("DJ") and Uinta Basins. The proceeds from selling our Piceance Basin and Powder River Basin properties allowed us to reduce debt and provide the capital to develop the DJ and Uinta Basin properties, where we believe we have at least 130 rig years of drilling inventory with strong economics. Furthermore, we increased our DJ Basin acreage position by nearly 8,000 net acres as part of a non-cash property exchange. Second, we transitioned our DJ Basin development to extended reach lateral ("XRL") pad drilling. Our 47,800 net acres land position in the Northeast Wattenberg features large contiguous acreage blocks. In addition, it has not been penetrated by the numerous legacy vertical wells found elsewhere in the Wattenberg. In combination, these factors make our acreage uniquely suited to drilling 9,000+ foot horizontal wells from multi-well pads. XRL drilling provides higher recoveries and superior economics with less surface disturbance. In 2014, we drilled and completed 24 XRL wells in the Niobrara "B" and "C" zones and are pleased with the initial results. Our technical team believes that more than 90% of our Northeast Wattenberg acreage can be drilled with XRLs. Execution of this strategy demonstrates that the Company is operationally and technically focused with financial discipline.

The year 2014 was not without its challenges, especially in the fourth quarter when oil prices plunged dramatically. However, our Company entered 2015 exceptionally well positioned for the current low commodity price environment. During 2014, we reduced net debt by $266 million and ended the year with $165 million in cash on hand and zero drawn on our revolving line of credit, providing ample liquidity. Substantially all of our 2015 oil production is hedged at $90+ WTI. Subsequent to year-end, we received a $43 million lease bonus refund from the federal government pursuant to a litigation settlement related to our Roan Plateau leasehold, further adding to our liquidity.

Our transitioned portfolio has resulted in a significant position in the DJ Basin, which is considered by most experts to be a top tier basin based on rates of return, even with lower oil prices. In 2015, we plan to reduce our capital spending by more than 50% and focus almost exclusively on XRL wells in the DJ Basin, which offer superior rates of return. The Company is highly focused on reducing all aspects of our cost structure: capital, general and administrative expenses, and lifting costs. We plan to deliver 10% production growth, pro forma for assets sold.

As we look longer term, we are excited about the growth prospects that our portfolio is poised to deliver. We will drive improved well performance by increasing our technical understanding of the reservoirs through core and other geophysical analysis. We will also strive for continuous improvement in our development program by optimizing well spacing and through the application of technology in our drilling and completion practices to maximize asset values. We believe that we can safely and economically develop our properties with the proper environmental safeguards for long-term shareholder value.

In summary, our transition process has enabled our Company to emerge stronger, more focused and financially healthy. We are well positioned to succeed in the current commodity price environment, and I look forward to reporting to you the value creation achieved in 2015.

Sincerely,

R. Scot Woodall
Chief Executive Officer and President
March 16, 2015

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

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2014

or

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

For the transition period from _________ to _________

Commission file number 001-32367

BILL BARRETT CORPORATION
(Exact name of registrant as specified in its charter)

Delaware	**80-0000545**
(State or other jurisdiction of incorporation or organization)	**(IRS Employer Identification No.)**
1099 18th Street, Suite 2300 Denver, Colorado	**80202**
(Address of principal executive offices)	**(Zip Code)**

(303) 293-9100

(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, $.001 par value	New York Stock Exchange
Series A Junior Participating Preferred Stock Purchase Rights	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 ☑ No

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 ☑ No

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 ☐ No

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 ☐ No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) 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. ☐

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). ☐ Yes ☑ No

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant as of June 30, 2014 based on the $26.78 closing price of the registrant's common stock on the New York Stock Exchange was $1,321,646,601.

* Calculated based on beneficial ownership of our common stock on January 27, 2015. Without assuming that any of the registrant's directors, executive officers, or 10 percent or greater beneficial owners is an affiliate, the shares of which they are beneficial owners have been deemed to be owned by affiliates solely for this calculation.

As of January 27, 2015, the registrant had 49,551,397 outstanding shares of $0.001 per share par value common stock.

DOCUMENTS INCORPORATED BY REFERENCE

The information required in Part III of this Annual Report on Form 10-K is incorporated by reference from the registrant's definitive proxy statement for the registrant's Annual Meeting of Stockholders to be held in May 2015 to be filed pursuant to Regulation 14A no later than 120 days after the end of the registrant's fiscal year ended December 31, 2014.

GLOSSARY OF OIL, NATURAL GAS AND NGL TERMS

The following are abbreviations and definitions of certain terms used in this document, which are commonly used in the oil and gas industry:

Bbl**.** Stock tank barrel, or 42 U.S. gallons liquid volume.

Bcf**.** Billion cubic feet of natural gas.

Boe**.** Barrel of oil equivalent, determined using the ratio of one Bbl of crude oil, condensate or natural gas liquids to six Mcf of natural gas.

Boe/d**.** Boe per day.

Btu or British thermal unit**.** The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Coalbed methane or CBM**.** Natural gas formed as a byproduct of the coal formation process, which is trapped in coal seams and can be produced into a pipeline.

Completion**.** Installation of permanent equipment for production of oil or gas, or, in the case of a dry well, to reporting to the appropriate authority that the well has been abandoned.

Condensate**.** A mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

Delineation. The process of drilling wells away from, or that is removed from, a known point of well control.

Developed acreage**.** The number of acres that are allocated or assignable to productive wells or wells capable of production.

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.

Down-dip**.** The occurrence of a formation at a lower elevation than a nearby area.

Drill-to-earn**.** The process of earning an interest in leasehold acreage by drilling a well pursuant to a farm-in, exploration, or other agreement.

Dry hole or Dry well**.** An exploratory, development, or extension well that proves to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

EHS. Environmental Health and Safety.

Environmental Assessment or EA**.** A study that can be required prior to drilling a federal well.

Environmental Impact Statement or EIS**.** A more detailed study of the potential direct, indirect and cumulative impacts of a federal project that is subject to public review and potential litigation.

EPA. The United States Environmental Protection Agency.

***E&P waste*.** Exploration and production waste, intrinsic to oil and gas drilling and production operations.

***Exploratory well*.** A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir.

***Field*.** An area consisting of either a single reservoir or multiple reservoirs, all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

***Gross acres or gross wells*.** The total acres or wells, as the case may be, in which a working interest is owned.

Henry Hub. The Erath, LA settlement point price as quoted in Platt's Gas Daily.

Horizontal drilling. A drill rig operation of drilling vertically to a defined depth and then mechanically steering the drill bit to drill horizontally within a designated zone typically defined as the prospective pay zone to be completed for oil and or gas.

Hydraulic fracturing. The injection of water, sand and additives under pressure, usually down casing that is cemented in the wellbore, into prospective rock formations at depth to stimulate natural gas and oil production.

***Identified drilling locations*.** Total gross locations specifically identified and scheduled by management as an estimation of our multi-year drilling activities on existing acreage. Our actual drilling activities may change depending on the availability of capital, regulatory approvals, seasonal restrictions, natural gas and oil prices, costs, drilling results and other factors.

***Infill drilling*.** The addition of wells in a field that decreases average well spacing. This practice both accelerates expected recovery and increases estimated ultimate recovery in heterogeneous reservoirs by improving the continuity between injectors and producers. As well spacing is decreased, the shifting well patterns alter the formation-fluid flow paths and increase sweep to areas where greater hydrocarbon saturations exist.

***MBbls*.** Thousand barrels of crude oil or other liquid hydrocarbons.

MBoe. Thousand barrels of oil equivalent, determined using the ratio of one Bbl of crude oil, condensate or natural gas liquids to six Mcf of natural gas.

***Mcf*.** Thousand cubic feet of natural gas.

***MMBbls*.** Million barrels of crude oil or other liquid hydrocarbons.

MMBoe. Million barrels of oil equivalent, determined using the ratio of one Bbl of crude oil, condensate or natural gas liquids to six Mcf of natural gas.

***MMBtu*.** Million British thermal units.

***MMcf*.** Million cubic feet of natural gas.

Net acres or net wells. The sum of the fractional working interest owned in gross acres or gross wells, as the case may be.

Net revenue interest**.** An owner's interest in the revenues of a well after deducting proceeds allocated to royalty and overriding interests.

NGLs. Natural gas liquids.

NWPL. Northwest Pipeline Corporation price as quoted in Platt's Inside FERC.

Play. A term used to describe an accumulation of oil and/or natural gas resources known to exist, or thought to exist based on geotechnical research, over a large area.

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.

Productive well**.** An exploratory, development, or extension well that is not a dry well.

Prospect**.** A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.

Proved developed producing reserves or PDP**.** Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Proved reserves. The quantities of oil, natural gas and natural gas liquids, 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.

Proved undeveloped reserves or PUD**.** 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.

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.

Resource Management Plan or RMP. A document that describes the U.S. Bureau of Land Management's intended uses of lands that are under its jurisdiction.

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.

SEC. U.S. Securities and Exchange Commission.

Shale gas. Considered to be an unconventional accumulation of natural gas where the gas is recovered from extremely low permeability shales, generally through the use of horizontal drilling and hydraulic fracturing.

***Standardized Measure*.** The present value of estimated future cash inflows from proved oil, natural gas and NGL reserves, less future development and production costs and future income tax expenses, using prices and costs as of the date of estimation without future escalation, without giving effect to hedging activities, non-property related expenses such as general and administrative expenses, debt service and depreciation, depletion and amortization and discounted using an annual discount rate of 10% to reflect timing of future cash flows.

***Undeveloped acreage*.** Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves.

***Working interest*.** The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production and requires the owner to pay a share of the costs of drilling and production operations.

WTI. West Texas Intermediate price as quoted on the New York Mercantile Exchange.

WTI Cushing. The West Texas Intermediate price at the Cushing, OK settlement point as quoted by Bloomberg, using crude oil price bulletins.

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K contains “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933, as amended, or the Securities Act, Section 21E of the Securities Exchange Act of 1934, as amended (the “Exchange Act”), and the Private Securities Litigation Reform Act of 1995. Forward-looking statements include statements about our future strategy, plans, estimates, beliefs, timing and expected performance.

All of these types of statements, other than statements of historical fact included in or incorporated into this Annual Report on Form 10-K, are forward-looking statements. These forward-looking statements may be found in “Items 1 and 2. Business and Properties”, “Item 1A. Risk Factors”, “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations” and other sections of this Annual Report on Form 10-K. In some cases, you can identify forward-looking statements by terminology such as “expect”, “seek”, “believe”, “upside”, “will”, “may”, “expect”, “anticipate”, “plan”, “will be dependent on”, “project”, “potential”, “intend”, “could”, “should”, “estimate”, “predict”, “pursue”, “target”, “objective”, or “continue”, the negative of such terms or other comparable terminology.

Forward-looking statements are dependent upon events, risks and uncertainties that may be outside our control. Our actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, the following risks and uncertainties:

- volatility of market prices received for oil, natural gas and NGLs;
- actual production;
- changes in the estimates of proved reserves;
- reductions in the borrowing base under our revolving bank credit facility (the “Amended Credit Facility”);
- legislative or regulatory changes that can affect our ability to permit wells and conduct operations, including ballot initiatives seeking moratoria or bans on drilling or hydraulic fracturing;
- availability of third party goods and services at reasonable rates;
- liabilities resulting from litigation concerning alleged damages related to environmental issues, pollution, contamination, personal injury, royalties, marketing, title to properties, validity of leases, regulatory penalties or other matters that may not be covered by an effective indemnity or insurance; and
- other uncertainties, including the factors discussed below and elsewhere in this Annual Report on Form 10-K, particularly in “Item 1A. Risk Factors” all of which are difficult to predict.

In light of these and other risks, uncertainties and assumptions, forward-looking events may not occur.

The forward-looking statements contained in this Annual Report on Form 10-K are largely based on our expectations, which reflect estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions and other factors. Although we believe such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. In addition, management's assumptions about future events may prove to be inaccurate. Management cautions all readers that the forward-looking statements contained in this Annual Report on Form 10-K are not guarantees of future performance, and we cannot assure any reader that such statements will be realized or that forward-looking events and circumstances will occur. Actual results may differ materially from those anticipated or implied in the forward-looking statements due to many factors including those listed above and in "Item 1A. Risk Factors" and elsewhere in this Annual Report on Form 10-K. All forward-looking statements speak only as of the date of this Annual Report on Form 10-K. Readers should not place undue reliance on these forward-looking statements, which reflect management's views only as of the date hereof. Other than as required under the securities laws, we do not intend to, and do not undertake any obligation to, publicly update or revise any forward-looking statements as a result of changes in internal estimates or expectations, new information, subsequent events or circumstances or otherwise. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

PART I

Items 1 and 2. Business and Properties.

BUSINESS

General

Bill Barrett Corporation together with our wholly-owned subsidiaries (“the Company”, “we”, “our” or “us”) is an independent energy company that develops, acquires and explores for oil and natural gas resources. All of our assets and operations are located in the Rocky Mountain region of the United States.

We develop oil and natural gas in the Rocky Mountain region of the United States. We seek to build stockholder value by delivering profitable growth in cash flow, reserves and production through the development of oil and natural gas assets. In order to deliver profitable growth, we allocate capital to our highest return assets, concentrate expenditures on exploiting our core assets, maintain capital discipline and optimize our operations while upholding high-level standards for health, safety and the environment. Substantially all of our revenues are generated through the sale of oil and natural gas production and NGL recovery at market prices.

We are committed to developing and producing oil and natural gas in a responsible and safe manner. Our employees work diligently with regulatory agencies, as well as environmental, wildlife and community organizations, to ensure that exploration and development activities meet stakeholders expectations and regulatory requirements.

We were formed in January 2002 and are incorporated in the State of Delaware. In December 2004, we completed an initial public offering of 14,950,000 shares of our common stock at a price to the public of $25.00 per share. Our common stock is traded on the New York Stock Exchange under the symbol “BBG”. The principal executive offices are located at 1099 18th Street, Suite 2300, Denver, Colorado 80202, and the telephone number at that address is (303) 293-9100.

We make available free of charge through our website our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to those reports as soon as reasonably practicable after such material is electronically filed with or furnished to the SEC via EDGAR and posted at http://www.sec.gov. Additionally, our Code of Business Conduct and Ethics, which includes our code of ethics for senior financial management, Corporate Governance Guidelines and the charters of our Audit Committee, Compensation Committee, Reserves and EHS Committee and Nominating and Corporate Governance Committee are posted on our website at http://www.billbarrettcorp.com and are available in print free of charge to any stockholder who requests them. Requests should be sent by mail to our corporate secretary at our principal office at 1099 18th Street, Suite 2300, Denver, Colorado 80202. We intend to disclose on our website any amendments or waivers to our Code of Business Conduct and Ethics that are required to be disclosed pursuant to Item 5.05 of Form 8-K. This Annual Report on Form 10-K and our website contain information provided by other sources that we believe are reliable. We cannot assure you that the information obtained from other sources is accurate or complete. No information on our website is incorporated by reference herein or deemed to be part of this Annual Report on Form 10-K.

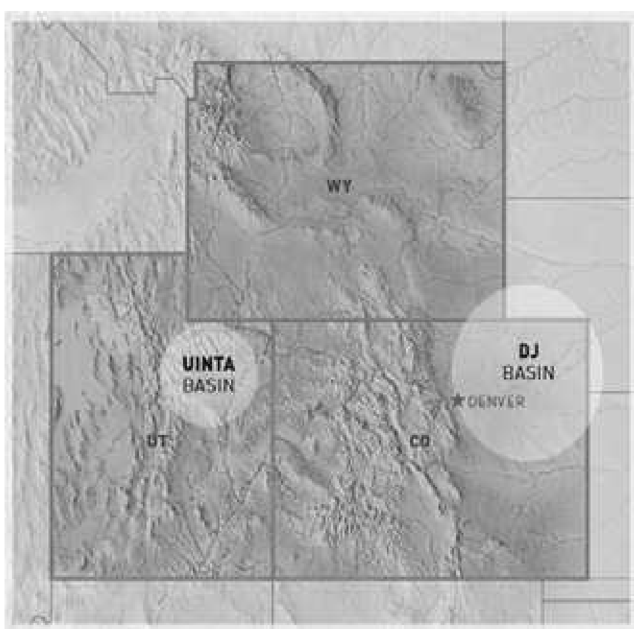
We operate in one industry segment, which is the exploration, development and production of oil and natural gas, and all operations are conducted in the United States. Consequently, we currently report a single reportable segment. See “Financial Statements” and the notes to our consolidated financial statements for financial information about this reportable segment.

The following table provides summary information by basin as of December 31, 2014:

Basin/Area	State	Estimated Net Proved Reserves (MMBoe) (1)	December 2014 Average Daily Net Production (Boe/d)	Net Producing Wells (2)	Net Undeveloped Acreage
Denver-Julesburg	CO/WY	73.1	9,152	250.2	56,924
Uinta Oil Program	UT	48.1	6,216	200.8	60,044(3)
Other	Various	1.1	218	10.6	364,048(4)
Total		122.3	15,586	461.6	481,016

(1) Our proved reserves were determined in accordance with SEC guidelines, using the average of the prices on the first day of each month in 2014 for natural gas (Henry Hub price) and oil (WTI Cushing price), which averaged $4.35 per MMBtu of natural gas and $94.99 per barrel of oil in 2014, respectively, without giving effect to hedging transactions. The average NGL price of $39.65 per barrel was based on a percentage of the SEC oil price per barrel using historical price data. Our reserves estimates are based on a reserve report prepared by us and audited by our independent third party petroleum engineers. See “—Oil and Gas Data—Proved Reserves”.
(2) Net wells are the sum of our fractional working interests owned in gross wells.
(3) Excludes an additional 66,820 net undeveloped acres that are subject to drill-to-earn agreements.
(4) Other includes 209,204 net undeveloped acres in the Paradox Basin.

Areas of Operation



Overview

As of December 31, 2014, we have two key areas of production: The Denver-Julesburg Basin ("DJ Basin") and the Uinta Oil Program in the Uinta Basin.

The following table shows changes in the mix of oil, natural gas and NGLs for both production and reserves over the periods presented:

	Year Ended December 31,								
	2014			2013			2012		
	Oil	Natural Gas	NGLs	Oil	Natural Gas	NGLs	Oil	Natural Gas	NGLs (1)
Production	44%	40%	16%	24%	61%	15%	14%	86%	— %
Proved reserves	69%	21%	10%	43%	39%	18%	29%	71%	— %

(1) For periods prior to January 1, 2013, we presented our production and reserve data for oil and natural gas, which combined NGLs with the natural gas stream, and did not separately report NGLs. This change impacts the comparability of periods 2013 and after with prior periods.

Denver-Julesburg Basin

The Company's acreage positions in the DJ Basin are predominantly located in Colorado's eastern plains and parts of southeastern Wyoming.

Key Statistics

- Estimated proved reserves as of December 31, 2014—73.1 MMBoe.
- Producing wells—We had interests in 388 gross (250.2 net) producing wells as of December 31, 2014, and we serve as operator in 254 gross wells.
- 2014 net production—2,809 MBoe.
- Acreage—We held 56,924 net undeveloped acres as of December 31, 2014.
- Capital expenditures—Our capital expenditures for 2014 were $384.0 million for participation in the drilling of 99 gross (58.1 net) wells, acquisition of leasehold acres and construction of gathering facilities.
- As of December 31, 2014, we were drilling 2 gross wells (1.8 net), and we were waiting to complete 13 gross (10.5 net) wells within the DJ Basin.
- As of December 31, 2014, we had a 58% weighted average working interest in producing wells in the DJ Basin.

Our DJ Basin acreage was acquired predominantly through two acquisitions completed in August 2011 and July 2012. The DJ Basin is a high growth oil development area where operators are targeting the Niobrara and Codell formations and employing new technologies to optimize oil recoveries and economic returns. We believe that the DJ Basin offers us significant growth with potential acreage additions to our current leasehold position, potential for increased well density (down-spacing), testing additional formations, increased utilization of extended reach (long lateral) horizontal wells, well completion optimization and ongoing cost reduction.

The DJ Basin is a core area of operation where we drilled 64 operated wells and completed 67 operated wells in 2014 and had three rigs operating at the end of 2014. In 2014, we focused on drilling extended reach horizontal wells in the Niobrara B, Niobrara C and Codell formations in the Northeast

Wattenberg area of the DJ Basin, optimizing our completion technology and establishing a scalable development program. The combination of this development along with nearby competitor activity significantly de-risked our approximate net 40,000 acres in the area.

The 2015 drilling program will be reduced in response to low commodity prices. We will utilize one rig for multi-well pad drilling of approximately 23 gross/17.3 net operated wells, plus we anticipate participating in approximately 28 non-operated wells. The 2015 operated drilling program is predominantly extended reach wells (9,000 foot laterals) along with some standard length wells (4,000 foot laterals), down spaced to 40-acre well density. This program may be modified throughout 2015 as business conditions and operating results warrant.

Our oil production is sold at the lease and trucked to markets. Our gas production is gathered and processed by various third parties and we receive residue gas and NGL revenue under percentage of proceeds contracts.

Uinta Basin

The Uinta Basin is located in northeastern Utah.

Key Statistics

- Estimated proved reserves as of December 31, 2014—48.1 MMBoe.
- Producing wells—We had interests in 350 gross (200.8 net) producing wells as of December 31, 2014, and we serve as operator in 257 gross wells.
- 2014 net production—2,310 MBoe.
- Acreage—We held 60,044 net undeveloped acres as of December 31, 2014, along with 66,820 net undeveloped acres that are subject to drill-to-earn agreements.
- Capital expenditures—In 2014, our capital expenditures were $152.9 million for participation in the drilling of 65 gross (37.2 net) wells, acquisition of leasehold acres and construction of gathering and salt water disposal facilities.
- As of December 31, 2014, we were drilling 1 gross well (0.3 net) and were waiting to complete 1 gross (1.0 net) well within the Uinta Basin.
- As of December 31, 2014, we had a 53% weighted average working interest in producing wells in the Uinta Oil Program.

The Uinta Oil Program includes four areas of development located in the Uinta Basin that we refer to as Blacktail Ridge, Lake Canyon, East Bluebell and South Altamont. The Uinta Oil Program has a sizable acreage position with a long-term drilling inventory, offering us significant growth potential. The resource is a stacked oil play with multiple pay zones, and our drilling program targets multiple zones from the Lower Green River through the Wasatch with vertical wells. The Uinta Oil Program is a core area of operation where we drilled and completed 52 operated wells during 2014.

During 2013, the Company conducted two 80-acre in-fill pilot projects, one in each of the southern and northern portions of the Blacktail Ridge area. Results to date indicate minimal, if any, interference with appropriate well orientation and led to the 80-acre downspacing of the greater Blacktail Ridge/ Lake Canyon areas in 2014.

In 2015, the Company will concentrate on development in the East Bluebell area with the drilling of 9 development wells.

Our oil production is sold at the lease and trucked to markets. Our gas production is gathered and processed by various third parties and we receive residue gas and NGL revenue under percentage of proceeds contracts.

Powder River Basin

The Powder River Basin is located in northeastern Wyoming. Our Powder River Oil Program targets various Cretaceous oil bearing horizons including the Parkman, Sussex, Shannon, Niobrara, Turner and Frontier formations through horizontal wells. We completed a sale and exchange of the majority of our Powder River Basin assets (the "Powder River Oil Divestiture") in four separate transactions with effective dates of April 1, 2014 and closing dates during the three months ended September 30, 2014. The remaining Powder River Basin assets are classified as held for sale as of December 31, 2014. See Note 4 of the Notes to Consolidated Financial Statements for more information related to this divestiture and assets held for sale.

Oil and Gas Data

Historically, we have presented separate reserve data for oil and natural gas. This is known as "two streams" reporting and is the manner in which all the data prior to January 1, 2013 below is presented. Beginning January 1, 2013, we modified our gas processing agreements with various processors to take title to NGLs resulting from the processing of our natural gas. Therefore, we have reported reserve and production data separately for oil, natural gas and NGLs for periods after January 1, 2013 below. This is known as "three streams reporting".

Proved Reserves

The following table presents our estimated net proved oil, natural gas and NGL reserves and the present value of our estimated proved reserves at each of December 31, 2014, 2013 and 2012 based on reserve reports prepared by us and audited by outside independent third party petroleum engineers. While we are not required by the SEC or accounting regulations or pronouncements to have our estimates independently audited, we are required by our revolving credit agreement with our lenders to have an independent third party engineering firm perform an annual audit of our estimated reserves. All of our proved reserves included in our reserve reports are located in North America. Netherland, Sewell & Associates, Inc., or "NSAI", audited all our reserves estimates at December 31, 2014, 2013 and 2012. NSAI is retained by and reports to the Reserves and EHS Committee of our Board of Directors, which is comprised of independent directors. When compared on a well-by-well or lease-by-lease basis, some of our internal estimates of net proved reserves are greater and some are less than the estimates of our outside independent third party petroleum engineers. However, in the aggregate, the independent third party petroleum engineer's estimates of total net proved reserves are within 10% of our internal estimates. In addition to a third party audit, our reserves are reviewed by our Reserves and EHS Committee. The Reserves and EHS Committee reviews the final reserves estimates in conjunction with NSAI's audit letter and meets with the key representative of NSAI to discuss NSAI's review process and findings. Our estimates of net proved reserves have not been filed with or included in reports to any federal authority or agency, other than the SEC, since January 1, 2014.

Proved Reserves:(1)(2)	As of December 31, 2014	2013	2012
Proved Developed Reserves:			
Oil (MMBbls)	29.3	26.3	20.7
Natural gas (Bcf)	50.6	238.7	492.1
NGLs (MMBbls) (3)	3.8	17.2	—
Total proved developed reserves (MMBoe) (4)	41.5	83.2	102.7
Proved Undeveloped Reserves:			
Oil (MMBbls)	54.5	57.2	30.1
Natural gas (Bcf)	103.3	227.7	247.1
NGLs (MMBbls) (3)	9.0	18.6	—
Total proved undeveloped reserves (MMBoe) (4)	80.8	113.7	71.2
Total Proved Reserves (MMBoe) (4)	122.3	197.0	174.0

(1) Our proved reserves were determined in accordance with SEC guidelines, using the average of the prices on the first day of each month in 2014 for natural gas (Henry Hub price) and oil (WTI Cushing price), which averaged $4.35 per MMBtu of natural gas and $94.99 per barrel of oil in 2014, respectively, without giving effect to hedging transactions. The average NGL price of $39.65 per barrel was based on a percentage of the SEC oil price per barrel using historical price data. Our reserves estimates are based on a reserve report prepared by us and audited by our independent third party petroleum engineers. See "– Oil and Gas Data – Proved Reserves".
(2) The comparability of the proved reserves for the periods presented are impacted by the 2012 Divestiture in 2012, the West Tavaputs Divestiture in 2013 and the Piceance Divestiture and Powder River Oil Divestiture in 2014. See Note 4 of the Notes to Consolidated Financial Statements for more information related to these divestitures.
(3) For periods prior to January 1, 2013, we presented our production and reserve data for oil and natural gas, which combined NGLs with the natural gas stream, and did not separately report NGLs. This change impacts the comparability of periods 2013 and after with prior periods.
(4) Total does not add due to rounding.

The data in the above table represent estimates only. Oil, natural gas and NGLs reserve engineering is an estimation of accumulations of oil, natural gas and NGLs that cannot be measured exactly. The accuracy of any reserves estimate is a function of the quality of available data and engineering and geological interpretation and judgment. Accordingly, reserves estimates may vary from the quantities of oil, natural gas and NGLs that are ultimately recovered. See "Item 1A. Risk Factors".

Proved developed oil, natural gas and NGLs reserves are proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped oil, natural gas and NGLs reserves are 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. Proved undeveloped reserves on undrilled acreage are limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having proved undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time. No proved undeveloped reserves can be attributed to any acreage for which an application of fluid injection or other improved recovery technique is contemplated unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

The following tables illustrate the history of our proved undeveloped reserves from December 31, 2012 through December 31, 2014:

Proved Undeveloped Reserves:	As of December 31, 2014	2013	2012
Beginning Balance (MMBoe)	113.7	71.2	111.6
Additions from drilling program	12.5	64.2	17.8
Acquisitions	7.4	—	—
Engineering/Price revisions	(6.0)	8.9	(15.2)
Converted to proved developed	(10.2)	(7.8)	(22.8)
Sold/Expired/Other	(36.6)	(22.8)	(20.2)
Total Proved Undeveloped Reserves (MMBoe)	80.8	113.7	71.2

	Year Ended December 31, 2014	2013	2012
Proved undeveloped locations converted to proved developed wells during year	65	49	179
Proved undeveloped drilling and completion capital invested (in millions)	$227.5	$118.8	$362.2
Proved undeveloped facilities capital invested (in millions)	$ 9.5	$ 6.8	$ 45.6
Percentage of proved undeveloped reserves converted to proved developed (1)	9.0%	11.0%	20.4%
Prior year's proved undeveloped reserves remaining undeveloped at current year end (MMBoe)	66.8	42.7	54.0

(1) Over the last three years our asset portfolio has significantly changed, resulting in a change in development focus. Due to low natural gas prices in 2012, drilling was halted in the Piceance Basin and the West Tavaputs area of the Uinta Basin, both of which were highly mature infill development programs and which together included the majority of our then remaining proved undeveloped drilling inventory, therefore, a relatively higher percentage of proved undeveloped locations were being converted to proved developed producing. Subsequently, the West Tavaputs assets were divested in 2013 and the Piceance assets were divested in 2014 with no further drilling activity. During 2013 and 2014, the development program was focused on the oil assets located in the DJ and Uinta Basins which are still relatively immature in their development as compared to the divested gas assets. Given our acreage positions in both the DJ and Uinta Basins, we concentrated developing unproven locations in order to assess the extent of the plays across our acreage. In 2015, we anticipate changing the mix of our drilling program to include drilling primarily infill proved undeveloped locations. We therefore expect the percentage of our proved undeveloped reserves converted to proved developed to increase significantly in 2015 relative to 2014 and 2013.

At December 31, 2014, our proved undeveloped reserves were 80.8 MMBoe. At December 31, 2013, our proved undeveloped reserves were 113.7 MMBoe. During 2014, 10.2 MMBoe, or 9.0% of our December 31, 2013 proved undeveloped reserves (65 wells), were converted into proved developed reserves and required $227.5 million of drilling and completion capital and $9.5 million of facilities capital. These wells produced 0.9 MMBoe in 2014. During 2014, we added 12.5 MMBoe of proved undeveloped reserves due to drilling programs in our core oil and gas development areas. During 2014, 36.6 MMBoe were removed from the proved undeveloped reserves category because they were not included in our near term development plans and were either traded, sold or removed. This volume includes 27.7 MMBoe of proved undeveloped reserves sold in the divestiture of our Piceance and Powder River Basin properties. Negative engineering and pricing revisions decreased proved undeveloped reserves by 6.0 MMBoe. In addition, we added 7.4 MMBoe of proved undeveloped reserves as a result of acquired property in the DJ Basin. The proved undeveloped reserves from December 31, 2013 that remained in the proved undeveloped reserves category at December 31, 2014 were 66.8 MMBoe.

At December 31, 2013, our proved undeveloped reserves were 113.7 MMBoe. At December 31, 2012, our proved undeveloped reserves were 71.2 MMBoe. During 2013, 7.8 MMBoe, or 11.0% of our December 31, 2012 proved undeveloped reserves (49 wells), were converted into proved developed reserves and required $118.8 million of drilling and completion capital and $6.8 million of facilities capital. These wells produced 0.7 MMBoe in 2013. During 2013, we added 64.2 MMBoe of proved undeveloped reserves due to drilling programs in our core oil and gas development areas. During 2013, 22.8 MMBoe were removed from the proved undeveloped reserves category because they were not included in our near term development plans and were either traded, sold or removed. This volume includes 10.5 MMBoe of proved undeveloped reserves sold in the divestiture of our West Tavaputs properties. Positive engineering and pricing revisions increased proved undeveloped reserves by 8.9 MMBoe. Significant pricing revisions occurred in many of our producing areas, particularly our Piceance Basin natural gas producing area, due to the pricing change from $2.56 per MMBtu CIG for the year ended December 31, 2012 to $3.67 per MMBtu Henry Hub for the year ended December 31, 2013 and from $91.21 per Bbl WTI for the year ended December 31, 2012 to $96.91 per Bbl WTI Cushing for the year ended December 31, 2013. Included in this amount were upward price and performance revisions of 6.6 MMBoe in the Piceance Basin, 3.1 MMBoe in the DJ Basin and 0.3 MMBoe in the Powder River Basin, offset by a 1.1 MMBoe downward engineering revision in the Uinta Oil Program due to lower than predicted performance in some of the wells drilled in the Blacktail Ridge and Lake Canyon areas in 2012. The proved undeveloped reserves from December 31, 2012 that remained in the proved undeveloped reserves category at December 31, 2013 were 42.7 MMBoe.

At December 31, 2012, we revised our total proved reserves downward by 21.2 MMBoe due to the combined effects of year end 2012 pricing and the 20-acre infill drilling performance at the West Tavaputs area.

We use our internal reserves estimates rather than the estimates of an independent third party engineering firm because we believe that our reservoir and operations engineers are more knowledgeable about the wells due to our continual analysis throughout the year as compared to the relatively short term analysis performed by third party engineers. We use our internal reserves estimates on all properties regardless of the positive or negative variance relative to the estimates of third party engineers. If a variance greater than 10% occurs at the field level, it may suggest that a difference in methodology or evaluation techniques exists between us and the third party engineers. We investigate any such differences and discuss the differences with the third party engineers to confirm that we used the proper methodologies and techniques in estimating reserves for the relevant field. These variances also are reviewed with our Reserves and EHS Committee. These differences are not resolved to a specified tolerance at the field or property level. In the aggregate, the third party petroleum engineer estimates of total net proved reserves are within 10% of our internal estimates.

The internal review process of our wells and the related reserves estimates, and the related internal controls we utilize, include but are not limited to the following:

- A comparison is made and documented of actual and historical data from our production system to the data in the reserve database. This is intended to ensure the accuracy of the production data, which supplies the basis for forecasting.
- A comparison is made and documented of land and lease record to interest data in the reserve database. This is intended to ensure that the costs and revenues will be properly determined in the reserves estimation.
- A comparison is made of the historical costs (capital and expenses) to the capital and lease operating costs in the reserve database. Documentation lists reasons for deviation from direct use of historical data. This is intended to ensure that all costs are properly included in the reserve database.
- A comparison is made of input data to data in the reserve database of all property acquisitions, disposals, retirements or transfers to verify that all are accounted for accurately.
- Natural gas and oil pricing based on the SEC pricing requirements are supplied by the third party independent engineering firm. Natural gas pricing for the first flow day of every month is collected from Platts Gas Daily Henry Hub price and oil pricing is collected from Bloomberg's WTI spot price. The average NGL price is based on a percentage of the WTI oil price per barrel.
- A final check is made of all economic data inputs in the reserve database by comparing them to documentation provided by our internal marketing, land, accounting, production and operations groups. This provides a second check designed to ensure accuracy of input data in the reserve database.
- Accurate classification of reserves is verified by comparing independent classification analyses by our internal reservoir engineers and the third party engineers. Discrepancies are discussed and differences are jointly resolved.
- Internal reserves estimates are reviewed by well and by area by the Vice President of Reservoir and Planning. A variance by well to the previous year-end reserve report is used in this process. This review is independent of the reserves estimation process.
- Reserves variances are discussed among the internal reservoir engineers and the Vice President of Reservoir and Planning. Our internal reserves estimates are reviewed by senior management and the Reserves and EHS Committee prior to publication.

Within our Company, the technical person primarily responsible for overseeing the preparation of the reserves estimates is William K Stenzel. Mr. Stenzel is our Vice President of Reservoir and Planning and became responsible for our reserves estimates starting in September 2014. Mr. Stenzel earned a Bachelor of Science degree in Civil Engineering from Colorado State University in 1977. Mr. Stenzel has over 37 years of experience in reserves and economic evaluations, as well as a broad experience in production, completions, reservoir analysis and planning and development.

The reserves estimates shown herein have been independently audited by NSAI, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within NSAI, the technical persons primarily responsible for auditing the estimates set forth in the NSAI audit letter incorporated herein are Mr. Dan Smith and Mr. John Hattner. Mr. Smith has been practicing consulting petroleum engineering at NSAI since 1980. Mr. Smith is a Licensed Professional Engineer in the State of Texas (No. 49093) and has over 30 years of experience in petroleum engineering and in the estimation and evaluation of reserves. He graduated from Mississippi State University in 1973 with a Bachelor of Science Degree in Petroleum Engineering. Mr. Hattner has been practicing consulting petroleum geology at NSAI since 1991. Mr. Hattner is a Licensed Professional Geoscientist in the State of Texas, Geology (No. 559) and has over 30 years of experience in petroleum geosciences, with over 20 years of experience in the estimation and evaluation of reserves. He graduated from University of Miami, Florida, in 1976 with a Bachelor of Science Degree in Geology; from Florida State University in 1980 with a Master of Science Degree in Geological Oceanography; and from Saint Mary's College of California in 1989 with a Master of Business Administration. Both technical principals meet or exceed 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; both are proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

NSAI performed a well-by-well audit of all of our properties and of our estimates of proved reserves and then provided us with its audit report concerning our estimates. The audit completed by NSAI, at our request, is a collective application of a series of procedures performed by NSAI. These audit procedures may be the same or different from audit procedures performed by other independent third party engineering firms for other oil and gas companies. NSAI's audit report does not state the degree of its concurrence with the accuracy of our estimate of the proved reserves attributable to our interest in any specific basin, property or well.

The NSAI audit process of our wells and reserves estimates is intended to determine the percentage difference, in the aggregate, of our internal net proved reserves estimate and future net revenue (discounted 10%) and the reserves estimate and net revenue as determined by NSAI. The audit process includes the following:

- The NSAI engineer performs an independent decline curve analysis on proved producing wells based on production and pressure data.
- The NSAI engineer may verify the production data with the public data.
- The NSAI engineer uses his or her individual interpretation of the information and knowledge of the reservoir and area to make an independent analysis of proved producing reserves.
- The NSAI technical staff may prepare independent maps and volumetric analyses on our properties and offsetting properties. They review our geologic maps, log data, core data, pertinent pressure data, test information and pertinent technical analyses, as well as data from offsetting producers.
- For the reserves estimates of proved non-producing and proved undeveloped locations, the NSAI engineer will estimate the potential for depletion by analogy to other wells in the basin drilled on varying well spacing.
- The NSAI engineer will estimate the hydrocarbon recovery of the remaining gas-in-place based upon his/her knowledge and experience.
- The NSAI engineer does not verify our working and net revenue interests or product price deductions.
- The NSAI engineer does not verify our capital costs although he/she may ask for confirming information and compare to basin analogs.
- The NSAI engineer reviews 12 months of operating cost, revenue and pricing information that we provide.
- The NSAI engineer confirms the oil and gas prices used for the SEC reserves estimate.

- NSAI confirms that its reserves estimate is within a 10% variance of our internal net reserves estimate and estimated future net revenue (discounted 10%), in the aggregate, before an audit letter is issued.
- The audit by NSAI is not performed such that differences in reserves or revenue on a well level are resolved to any specific tolerance.

The reserves audit letter provided by NSAI states that “in our opinion the estimates of Bill Barrett’s proved reserves and future revenue shown herein are, in the aggregate, reasonable” following an independent estimation of reserve quantities with economic parameters and other factual data provided by us and accepted by NSAI. The audit letter also includes a statement of dates pertaining to the NSAI work performed, the methodology used, the assumptions made and a discussion of uncertainties that they believe are inherent in reserves estimates.

Future prices received for production and costs may vary, perhaps significantly, from the prices and costs assumed for purposes of these estimates. The Standardized Measure shown in the Financial Statements should not be construed as the current market value of the reserves. The 10% discount factor used to calculate present value, which is required by Financial Accounting Standards Board pronouncements (“FASB”), is not necessarily the most appropriate discount rate. The present value, no matter what discount rate is used, is materially affected by assumptions as to timing of future production, which may prove to be inaccurate.

From time to time, we engage NSAI to review and/or evaluate the reserves of properties that we are considering purchasing and to provide technical consulting on well testing. NSAI and its respective employees have no interest in those properties, and the compensation for these engagements is not contingent on NSAI’s estimates of reserves and future cash inflows for the subject properties. During 2014 and 2013, we paid NSAI approximately $400,000 and $550,000, respectively, for auditing our reserves estimates.

Production and Cost History

The following table sets forth information regarding net production of oil, natural gas and NGLs and certain cost information for each of the periods indicated:

	Year Ended December 31,		
	2014	2013	2012
Company Production Data:			
Oil (MBbls)	4,012	3,495	2,687
Natural gas (MMcf)	21,744	52,685	101,486
NGLs (MBbls)	1,476	2,199	—
Combined volumes (MBoe)	9,112	14,475	19,601
Daily combined volumes (Boe/d)	24,964	39,658	53,701
Piceance—Gibson Gulch Production Data (1)(2):			
Oil (MBbls)	177	331	619
Natural gas (MMcf)	14,808	25,470	48,072
NGLs (MBbls)	911	1,858	—
Combined volumes (MBoe)	3,556	6,434	8,631
Daily combined volumes (Boe/d)	9,742	17,627	23,647
DJ Basin—Production Data (1):			
Oil (MBbls)	1,682	757	397
Natural gas (MMcf)	4,224	2,016	1,264
NGLs (MBbls)	423	195	—
Combined volumes (MBoe)	2,809	1,288	608
Daily combined volumes (Boe/d)	7,696	3,529	1,666
Uinta—Oil Program Production Data (1):			
Oil (MBbls)	1,821	1,996	1,479
Natural gas (MMcf)	2,220	3,024	2,653
NGLs (MBbls)	119	142	—
Combined volumes (MBoe)	2,310	2,642	1,921
Daily combined volumes (Boe/d)	6,329	7,238	5,263
Uinta—West Tavaputs Production Data (1)(3):			
Oil (MBbls)	—	30	61
Natural gas (MMcf)	—	21,714	34,497
NGLs (MBbls)	—	—	—
Combined volumes (MBoe)	—	3,649	5,810
Daily combined volumes (Boe/d)	—	9,997	15,918
Average Costs ($ per Boe):			
Lease operating expense	$ 6.62	$ 4.85	$ 3.71
Gathering, transportation and processing expense	3.89	4.65	5.44
Total production costs excluding production taxes	$ 10.51	$ 9.50	$ 9.15
Production tax expense	3.44	1.88	1.30
Depreciation, depletion and amortization (4)	25.88	19.33	17.49
General and administrative (5)	4.61	3.39	2.66

(1) The DJ Basin and the Uinta Oil Program in the Uinta Basin were the only development areas that contained 15% or more of our total proved reserves as of December 31, 2014. The Gibson Gulch area in the Piceance Basin, the Uinta Oil Program in the Uinta Basin and the DJ Basin were the only development areas that contained 15% or more of our total proved reserves as of

December 31, 2013. The Gibson Gulch area in the Piceance Basin and West Tavaputs area in the Uinta Basin were the only development areas that contained 15% or more of our total proved reserves as of December 31, 2012.

(2) On September 30, 2014, the Company completed the sale of its Gibson Gulch natural gas program in the Piceance Basin (the “Piceance Divestiture”). As a result, the production and cost data related to the Piceance Basin as reported above includes values through the closing date of September 30, 2014. See Note 4 of the Notes to Consolidated Financial Statements for more information related to this divestiture.

(3) On December 10, 2013, the Company completed the sale of its West Tavaputs natural gas assets in the Uinta Basin (the “West Tavaputs Divestiture”). As a result, the production and cost data related to West Tavaputs as reported above includes values through the closing date of December 10, 2013. See Note 4 of the Notes to Consolidated Financial Statements for more information related to this divestiture.

(4) The depreciation, depletion and amortization (“DD&A”) per Boe as calculated based on the DD&A expense and Boe production data presented in the table for the year ended December 31, 2012 was $16.67. However, the DD&A rate per Boe for the year ended December 31, 2012 of $17.49, as presented in the table above, excludes fourth quarter production of 911 MBoe associated with our properties that were sold as of December 31, 2012.

(5) General and administrative expense presented herein excludes non-cash stock-based compensation of $11.4 million, $15.8 million and $16.4 million for the years ended December 31, 2014, 2013 and 2012, respectively. If included, these non-cash stock based compensation expenses would have increased general and administrative expense by $1.25, $1.09 and $0.84 per Boe for the years ended December 31, 2014, 2013 and 2012, respectively. General and administrative expense excluding non-cash stock-based compensation is a non-GAAP measure. Non-cash stock-based compensation is combined with general and administrative expense for a total of $53.4 million, $64.9 million and $68.7 million for the years ended December 31, 2014, 2013 and 2012, respectively, in the Consolidated Statements of Operations. Management believes the separate presentation of the non-cash component of general and administrative expense is useful because the cash portion provides a better understanding of our required cash for general and administrative expense. We also believe that this disclosure allows for a more accurate comparison to our peers, which may have higher or lower non-cash stock-based compensation expense.

Productive Wells

The following table sets forth information at December 31, 2014 relating to the productive wells in which we owned a working interest as of that date. Productive wells consist of producing wells and wells capable of production, including natural gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities. Gross wells are the total number of producing wells in which we have an interest, and net wells are the sum of our fractional working interests owned in gross wells.

	Oil		Gas	
Basin	**Gross Wells**	**Net Wells**	**Gross Wells**	**Net Wells**
DJ	244.0	151.2	144.0	99.0
Uinta Oil Program	345.0	199.9	5.0	0.9
Other	27.0	9.0	3.0	1.6
Total	616.0	360.1	152.0	101.5

Developed and Undeveloped Acreage

The following table sets forth information as of December 31, 2014 relating to our leasehold acreage.

Basin/Area	Developed Acreage (1) Gross	Developed Acreage (1) Net	Undeveloped Acreage (2) Gross	Undeveloped Acreage (2) Net
DJ	53,093	39,731	98,552	56,924
Uinta Oil Program	66,893	45,019	132,324	60,044 (3)
Other	17,279	14,148	487,267	364,048
Total	137,265	98,898	718,143	481,016 (3)

(1) Developed acres are acres spaced or assigned to productive wells.
(2) Undeveloped acres are acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or natural gas, regardless of whether such acreage contains proved reserves.
(3) Does not include an additional 152,571 gross and 66,820 net undeveloped acres that are subject to drill-to-earn agreements.

Substantially all of the leases comprising the undeveloped acreage set forth in the table above will expire at the end of their respective primary terms unless production from the leasehold acreage has been established prior to such date, in which event the lease will remain in effect until the cessation of production. We generally have been able to obtain extensions of the primary terms of our federal leases for periods in which we have been unable to obtain drilling permits due to environmental stipulations, pending environmental analysis or related legal challenge. The following table sets forth, as of December 31, 2014, the expiration periods of the gross and net acres that are subject to leases summarized in the above table of undeveloped acreage.

Years Ending:	Undeveloped Acres Expiring Gross	Undeveloped Acres Expiring Net
December 31, 2015	184,415	120,155 (1)
December 31, 2016	128,028	85,589
December 31, 2017	76,385	50,162
December 31, 2018	76,522	65,466
December 31, 2019 and later	252,793	159,644 (2)
Total	718,143	481,016

(1) Includes 115,377 gross and 78,410 net acres that will expire in the Paradox Basin.
(2) Includes 198,799 gross and 114,987 net undeveloped acres held by production from other leasehold acreage or held by federal units.

Drilling Results

The following table sets forth information with respect to wells completed during the periods indicated. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation between the number of productive wells drilled and quantities or value of reserves found. Productive wells are wells that are found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.

	Year Ended December 31,					
	2014		2013		2012	
	Gross	Net	Gross	Net	Gross	Net
Development						
Productive	94.0	72.7	164.0	85.8	324.0	218.7
Dry	—	—	—	—	—	—
Exploratory						
Productive	—	—	—	—	3.0	1.5
Dry	—	—	—	—	3.0	2.7
Total						
Productive	94.0	72.7	164.0	85.8	327.0	220.2
Dry	—	—	—	—	3.0	2.7

Operations

General

In general, we serve as operator of wells in which we have a greater than 50% working interest. In addition, we seek to be operator of wells in which we have lesser interests. As operator, we obtain regulatory authorizations, design and manage the development of a well and supervise operation and maintenance activities on a day-to-day basis. We do not own drilling rigs or the majority of the other oil field service equipment used for drilling or maintaining wells on the properties we operate. Independent contractors engaged by us provide the majority of the equipment and personnel associated with these activities. We do construct, operate and maintain gas gathering facilities associated with our operations. We employ drilling, production and reservoir engineers and geologists and other specialists who work to improve production rates, increase reserves and lower the cost of operating our oil and natural gas properties.

Marketing and Customers

We market the majority of the oil production from our operated properties. Our natural gas and related NGLs are generally marketed by third parties under percentage of proceeds (“POP”) contracts. We sell our production to a variety of purchasers under contracts with daily, monthly, seasonal, annual or multi-year terms, all at market prices. Purchasers include pipelines, processors, refineries, marketing companies and end users. We normally sell production to a relatively small number of customers, as is customary in the development and production business. However, based on where we operate and the availability of other purchasers and markets, we believe that the loss of any of our major purchasers would not have a material adverse effect on our financial condition or results of operations as there are competitive markets available.

During 2014, four customers accounted for 52% of our oil and gas production revenues. During 2013, five customers accounted for 49% of our oil and gas production revenues. During 2012, four customers accounted for 50% of our oil and gas production revenues.

We enter into hedging transactions with unaffiliated third parties for portions of our production to achieve more predictable cash flows and to reduce our exposure to fluctuations in commodities prices. For a more detailed discussion, see “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations – Overview” and “Item 7A. Quantitative and Qualitative Disclosures About Market Risk”.

Our oil production is collected in tanks on location and sold to third parties that collect the oil in trucks and transport it to pipelines, rail terminals and refiners. We sell our oil production to a variety of purchasers under monthly, annual or multi-year terms. Our oil contracts are priced off of either New York Mercantile Exchange (“NYMEX”) or area oil posting with quality, location or transportation differentials.

The following table sets forth information about material long-term firm natural gas pipeline transportation contracts, which entail a demand charge for reservation of capacity. These contracts were initiated to provide a guaranteed outlet for company marketed production from the West Tavaputs area of the Uinta Basin and the Gibson Gulch area of the Piceance Basin. These transportation contracts were not included in the sales of these assets in December 2013 and September 2014, respectively. Accordingly, the Company will continue to incur monthly demand charges of approximately $1.5 million for the remaining term of six years even though it no longer utilizes these contracts.

Type of Arrangement	Pipeline System / Location	Deliverable Market	Gross Deliveries (MMBtu/d)	Term
Firm Transport	Questar Overthrust [1]	Rocky Mountains	50,000	08/11 – 07/21
Firm Transport	Ruby Pipeline	West Coast	50,000	08/11 – 07/21

(1) This contract was entered into in conjunction with the Ruby Pipeline contract; it has an end date of 10 years from the in-service date of the Ruby Pipeline.

Hedging Activities

We have an active commodity hedging program, the purpose of which is to mitigate the risks of volatile prices of oil, natural gas, and NGLs. Typically, we intend to hedge approximately 50% to 70% of our anticipated oil, natural gas and NGLs production on a forward 12-month to 18-month basis using a combination of swaps, cashless collars and other financial derivative instruments with counterparties that we believe are creditworthy. We currently have hedged approximately 90% of our expected 2015 production at price levels that provide a degree of economic certainty to our capital investments. To date eight of our 17 lenders (or affiliates of lenders) under our credit facility are also hedging counterparties. We are not required to post collateral for these hedges other than the security for our credit facility. For additional information on our hedging activities, see “Item 7A. Quantitative and Qualitative Disclosures About Market Risk”.

Competition

The oil and gas industry is intensely competitive, and we compete with a large number of other companies, some of which have greater resources. Many of these companies not only explore for and produce oil, natural gas and NGLs, but also carry on midstream and refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for productive oil, natural gas and NGLs properties and exploratory prospects or define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, these companies have a greater ability to continue exploration activities during periods of low oil, natural gas and NGLs market prices. Our larger or integrated competitors may be better able than we are to absorb the burden of existing, and any changes to, federal, state, local and Native American tribal laws and regulations, and this could adversely affect our competitive position. Our ability to acquire additional properties and to discover reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, because we have fewer financial and human resources than many companies in our industry, we may be at a disadvantage in bidding for exploratory prospects and producing oil, natural gas and NGLs properties.

Title to Properties

As is customary in the oil and gas industry, we initially conduct only a cursory review of the title to our properties on which we do not have proved developed reserves. Prior to the commencement of drilling operations on those properties, we conduct a thorough title examination and perform curative work for significant defects. To the extent title opinions or other investigations reflect title defects on those properties, we are typically responsible for curing such defects at our expense. We generally will not commence drilling operations on a property until we have cured any material title defects on such property. We have obtained title opinions on substantially all of our producing properties and believe that we utilize methods consistent with practices customary in the oil and gas industry and that our practices are adequately designed to enable us to acquire satisfactory title to our producing properties. Prior to completing an acquisition of producing oil and gas leases, we perform title reviews on the most significant leases and, depending on the materiality of the properties, we may obtain a title opinion or review previously obtained title opinions. Our oil, natural gas and NGL producing properties are subject to customary royalty and other interests, liens for current taxes, liens under our credit facility and other burdens that we believe do not materially interfere with the use of our properties or affect the carrying value of the properties.

Seasonal Nature of Business

Generally, but not always, the demand for natural gas decreases during the spring and fall months and increases during the summer and winter months. Seasonal anomalies such as mild winters or cool summers sometime lessen this fluctuation. In addition, certain natural gas users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during lower demand periods. This can also lessen seasonal demand fluctuations. Seasonal weather conditions and lease stipulations can limit our drilling and producing activities and other oil and natural gas operations in certain areas of the Rockies. These seasonal anomalies can pose challenges for meeting our well drilling objectives and can increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages and increase costs or delay our operations.

Environmental Matters and Regulation

General. Our operations are subject to comprehensive federal, state and local laws and regulations governing the discharge of materials into the environment, management of E&P waste, or otherwise relating to environmental protection. Our operations are generally subject to the same environmental laws and regulations as other companies in the oil and gas exploration and production industry. These laws and regulations:

- require the acquisition of various permits before drilling commences;
- require the installation of effective emission control equipment;

- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with drilling and production activities;
- limit or prohibit drilling activities on lands lying within environmentally sensitive areas, wilderness, wetlands and other protected areas, including areas proximate to residential areas and certain high-occupancy buildings;
- require measures to prevent pollution from current operations, such as E&P waste management, transportation and disposal requirements;
- require measures to prevent pollution from former operations, such as pit closure and plugging of abandoned wells;
- impose substantial penalties for any non-compliance with federal, state and local laws and regulations;
- impose substantial liabilities for any pollution resulting from our operations;
- with respect to operations affecting federal lands or leases, require time consuming environmental analysis with uncertain outcomes;
- expose us to litigation by environmental and other special interest groups; and
- impose certain compliance and regulatory reporting requirements.

These laws, rules and regulations may also restrict the rate of oil, natural gas and NGLs production below the rate that would otherwise be possible, for example, by limiting the flaring of associated natural gas from an oil well while awaiting a pipeline connection. The regulatory burden on the oil and gas industry increases the cost and timing of doing business and consequently affects profitability. Additionally, Congress and federal and state agencies frequently revise the environmental laws and regulations, and any changes that result in delay or more stringent and costly permitting, waste handling, disposal and clean-up requirements for the oil and gas industry could have a significant impact on our operating costs.

We believe that we are, and have historically been, in substantial compliance with all applicable environmental laws and regulations. We have made and will continue to make expenditures in our efforts to comply with all environmental regulations and requirements. We consider these a normal, recurring cost of our ongoing operations and not extraordinary. We believe that our compliance with existing requirements has been accounted for and will not have a material adverse impact on our financial condition and results of operations. However, we cannot predict the passage of or quantify the potential impact of any more stringent future laws and regulations. For the year ended December 31, 2014, we did not incur any material capital expenditures for remediation of well sites or production facilities or to retrofit emission control equipment at any of our facilities.

The environmental laws and regulations that could have a material impact on the oil and natural gas exploration and production industry and our business are as follows:

National Environmental Policy Act. Oil, natural gas and NGLs exploration and production activities on federal lands are subject to the National Environmental Policy Act, or NEPA. NEPA requires federal agencies, including the Departments of the Interior and Agriculture, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will have an environmental assessment prepared that assesses the potential direct, indirect and cumulative impacts of a proposed project and project alternatives. If impacts are considered significant, the agency will prepare a more detailed Environmental Impact Statement. These environmental analyses are made available for public review and comment. All of our current exploration and production activities, as well as proposed exploration and development plans, on federal lands require governmental permits that trigger the requirements of NEPA. Certain federal permits on non-federal lands may also trigger NEPA requirements. This process has the potential to delay the development of oil and natural gas projects. Authorizations under NEPA also are subject to protest, appeal or litigation, which can delay or halt projects.

Waste Handling. The Resource Conservation and Recovery Act, or RCRA, and comparable state statutes affect oil and gas exploration and production activities by imposing regulations on the generation, transportation, treatment, storage, disposal and cleanup of “hazardous wastes” and on the disposal of non-hazardous wastes. Under the oversight of the Environmental Protection Agency, or EPA, the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Federal and state regulatory agencies can impose administrative penalties, civil and criminal judicial actions, as well as other enforcement mechanisms for non-compliance with RCRA or corresponding state programs. RCRA also imposes cleanup liability related to the mismanagement of regulated wastes. Drilling fluids, produced waters and most of the other wastes associated with the exploration, development and production of crude oil, natural gas, or geothermal energy are currently exempt from regulation under the hazardous waste provisions of RCRA, but there is no guarantee that the EPA or the individual states will not adopt more stringent requirements for the handling of non-hazardous wastes or categorize some non-hazardous wastes as hazardous for future regulation. Indeed, legislation has been proposed from time to time in Congress to reverse the exemption. In addition, certain environmental groups have petitioned the EPA to reverse the exemption.

We believe that we are in substantial compliance with the requirements of RCRA and related state and local laws and regulations, and that we have held, and continue to hold, all necessary and up-to-date approvals, permits, registrations and other authorizations to the extent that our operations require them under such laws and regulations. Although we believe that the current costs of managing our wastes as they are presently classified are reflected in our budget, any legislative or regulatory reclassification of oil and natural gas exploration and production wastes could increase our costs to manage and dispose of such wastes.

Comprehensive Environmental Response, Compensation and Liability Act. The Comprehensive Environmental Response, Compensation and Liability Act, or CERCLA, also known as the “Superfund” law, imposes strict, joint and several liability, without regard to fault or legality of conduct, on classes of persons who are considered to be potentially responsible for a release or threatened release of a “hazardous substance” (generally excluding petroleum) into the environment. These persons may include current and past owners or operators of a disposal site, or site where the release or threatened release of a “hazardous substance” occurred, and companies that disposed of or arranged for the disposal of the hazardous substance at such sites. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims under CERCLA and/or state common law for cleanup costs, personal injury and property damage allegedly caused by the hazardous substances released into the environment. In the course of our operations, we use materials that, if released, could be subject to CERCLA. Therefore, governmental agencies or third parties may seek to hold us responsible under CERCLA for all or part of the costs to clean up sites at which such “hazardous substances” have been released.

Water Discharges. The Federal Water Pollution Control Act, also known as the Clean Water Act, and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants, including produced water, stormwater drainage and other oil and gas wastes, into waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or the state. These laws also prohibit the discharge of dredge and fill material in regulated waters, including jurisdictional wetlands, unless authorized by a permit issued by the U.S. Army Corps of Engineers ("Corps"). Federal and state regulatory agencies can impose administrative penalties, civil and criminal penalties, and take judicial action for non-compliance with discharge permits or other requirements of the federal Clean Water Act and analogous state laws and regulations. The EPA and the Corps have commenced a federal rulemaking to revise the jurisdictional definition of "waters of the United States" with a final rule expected in Spring 2015. This rulemaking may expand the definition of "waters of the United States" to include certain waters, including wetland and tributaries not currently regulated. This definition would subject those waters to permitting under the Clean Water Act, including permits under Section 404 of the Clean Water Act for wetlands development. Obtaining permits has the potential to delay the development of oil and natural gas projects. These same regulatory programs may also limit the total volume of water that can be discharged, hence limiting the rate of development.

Air Emissions. The Federal Clean Air Act, and associated state laws and regulations, regulate emissions of various air pollutants through the issuance of permits, emission reporting, and the imposition of emission control requirements. Most of our facilities are now required to obtain permits before work can begin, and existing facilities are often required to incur capital costs in order to maintain compliance with those permits, laws and regulations. In 2012, the EPA issued new New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP) specific to the oil and gas industry, including air standards for natural gas wells that are hydraulically fractured, and has issued several amendments to the NSPS rules in 2013 and 2014, respectively. In addition, the EPA has deemed carbon dioxide ("CO2") and other greenhouse gases, including methane, to be a danger to public health, which is leading to regulation of greenhouse gases in a manner similar to other pollutants. For example, the EPA announced it will be proposing new regulations focused on methane emissions from the oil and gas industry in Summer 2015, with a final rule expected in 2016. The EPA already requires reporting of greenhouse gases, such as CO2 and methane, from operations. In February 2014, Colorado strengthened its oil and gas air regulations, including the adoption of the first set of fugitive methane emission control regulations in the United States. In January 2015, the EPA proposed similar national requirements, with a Summer 2105 target date. In addition, the EPA is proposing to lower the national ambient air quality standard for ozone pollution, which may require the oil and gas industry to further reduce emissions of volatile organic compounds and nitrogen oxides. These state and federal regulations may increase the costs of compliance for some facilities we own or operate, and federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the Federal Clean Air Act and associated state laws and regulations.

Hydraulic Fracturing. Our completion operations are subject to regulation, which may increase in the short or long-term. The well completion technique known as hydraulic fracturing is used to stimulate production of natural gas and oil and has come under increased scrutiny by the environmental community, as well as local, state and federal jurisdictions. Hydraulic fracturing involves the injection of water, sand and chemical additives under pressure into prospective rock formations at depth to stimulate oil and natural gas production. We use this completion technique on all of our wells to obtain commercial production.

Under the direction of Congress, the EPA has undertaken a study of the effect, if any, of hydraulic fracturing on drinking water and groundwater. The EPA has also announced its plan to propose pre-treatment standards under the Clean Water Act for wastewater discharges from shale hydraulic fracturing operations. Congress may consider legislation to amend the Federal Safe Drinking Water Act or the Toxic Substances Control Act to require the disclosure of chemicals used by the oil and gas industry in the hydraulic fracturing process. Certain states, including Colorado, Utah and Wyoming, have already issued such disclosure rules. Several environmental groups have also petitioned the EPA to extend release reporting requirements under the Emergency Planning Community Right-to-Know

Act to the oil and gas extraction industry. In addition, the Department of the Interior has proposed expanded or new regulations concerning the use of hydraulic fracturing on lands under its jurisdiction, which includes some of the lands on which we conduct or plan to conduct operations. In Colorado, certain local jurisdictions have imposed moratoria or bans on hydraulic fracturing, several of which have been invalidated in court, but are now on appeal. In 2014, a citizen initiative that would have empowered local governments to ban hydraulic fracturing was certified for the November ballot. Another initiative would have imposed a statewide 2,000 foot drilling setback to homes or other occupied buildings. These initiatives were withdrawn from the ballot under an arrangement between Colorado Governor Hickenlooper and Congressman Polis, a financial supporter of these initiatives, that entailed the appointment of a Task Force to consider legislative and regulatory measures to address the concerns underlying the initiative effort. The recommendations of this Task Force may impact our operations, but are unlikely to deter future attempts to advance measures restricting drilling or hydraulic fracturing in the next election cycle. Opponents of hydraulic fracturing received encouragement when New York banned the practice for the foreseeable future. Should measures restricting or banning the practice of hydraulic fracturing succeed in Colorado, the impact on the Company and the industry in general would be severe, and could force us to seek other basins in which to operate. The Company participates in industry organizations that have mobilized to combat such measures.

Climate Change. In June 2014, the U.S. Supreme Court upheld a portion of the EPA's greenhouse gas regulatory program for certain major sources in the *Utility Air Regulatory Group v. EPA* case. The EPA has proposed significant new rules to curb carbon emissions from power plants and other industrial activities, known as the Clean Power Plan. These rules are expected to be finalized in Summer 2015. In addition, certain environmental groups are agitating for scaling back, or eliminating, fossil fuel extraction and use, including efforts to convince policy-makers that the majority of known oil and gas reserves must never leave the ground. These groups are mobilizing around a movement for global divestment from fossil fuel companies, which, if effective, could affect the market for our securities. Potential future laws or regulations addressing greenhouse gas emissions could impact our business by limiting emissions of methane, restricting the flaring or venting of natural gas, or by reducing demand for oil or natural gas.

Homeland Security. Legislation continues to be introduced in Congress, and development of regulations continues in the Department of Homeland Security and other agencies, concerning the security of industrial facilities, including oil and natural gas facilities. Our operations may be subject to such laws and regulations. Presently, it is not possible to accurately estimate the costs we could incur to comply with any such facility security laws or regulations, but such expenditures could be substantial.

Other Regulation of the Oil and Gas Industry

Our operations are subject to other types of regulation at federal, state, local and Native American tribal levels. These types of regulation include requiring permits for the drilling of wells, bonds securing plugging, abandonment and reclamation obligations, and reports concerning our operations. Most states, and some counties, municipalities and Native American tribes also regulate one or more of the following:

- the location of wells and surface facilities;
- the method of drilling and casing wells;
- the rates of production or "allowables";
- the surface use and restoration of properties upon which wells are drilled;

- wildlife management and protection;
- the protection of archeological and paleontological resources;
- the plugging and abandoning of wells; and
- notice to, and consultation with, surface owners and other third parties.

State laws regulate the size and shape of drilling and spacing units or proration units governing well density and location, as well as the pooling of oil and natural gas properties. Some states provide statutory mechanisms for compulsory pooling or integration of tracts to facilitate exploration, while other states rely on voluntary pooling of lands and leases. In some instances, compulsory pooling or unitization may be implemented by third parties and subject our interest to third party operations. While not currently an issue in Colorado or Utah, other states establish maximum rates of production from oil and natural gas wells and impose requirements regarding ratable takes by purchasers of production. Such laws and regulations, if adopted in Colorado or Utah, might limit the amount of natural gas and oil we can produce from our wells or limit the number of wells or the locations at which we can drill. Moreover, our production is generally subject to multiple layers of severance and/or ad valorem taxation by states, counties and tribes.

Natural Gas Sales and Transportation. Historically, federal legislation and regulatory controls have affected the price of the natural gas we produce and the manner in which we market our production. The Federal Energy Regulatory Commission, or FERC, has jurisdiction over the transportation and sale or resale of natural gas in interstate commerce by natural gas companies under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. Since 1978, various federal laws have been enacted that have resulted in the complete removal of all price and non-price controls for “first sales” of domestic natural gas, which include all of our sales of our own production.

FERC also regulates interstate natural gas transportation rates and service conditions, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas. Commencing in 1985, FERC promulgated a series of orders, regulations and rule makings that significantly fostered competition in the business of transporting and marketing gas. Today, interstate pipeline companies are required to provide nondiscriminatory transportation services to producers, marketers and other shippers, regardless of whether such shippers are affiliated with an interstate pipeline company. FERC’s initiatives have led to the development of a competitive, unregulated, open access market for gas purchases and sales that permits all purchasers of gas to buy gas directly from third-party sellers other than pipelines. However, the natural gas industry historically has been very heavily regulated; therefore, we cannot guarantee that the less stringent regulatory approach pursued by FERC and Congress over the past few decades will continue indefinitely into the future, nor can we determine what effect, if any, future regulatory changes may have on our natural gas-related activities.

Operations on Native American Reservations. A portion of our leases in the Uinta Basin are, and some of our future leases in this and other areas may be, regulated by Native American tribes. In addition to regulation by various federal, state and local agencies and authorities, an entirely separate and distinct set of laws and regulations applies to lessees, operators and other parties within the boundaries of Native American reservations. Various federal agencies within the U.S. Department of the Interior, particularly the Office of Natural Resources Revenue, the Bureau of Indian Affairs, the Bureau of Land Management, or BLM, and the EPA, together with each Native American tribe, promulgate and enforce regulations pertaining to oil and gas operations on Native American reservations. These regulations include lease provisions, royalty matters, drilling and production requirements, environmental standards, tribal employment and tribal contractor preferences and numerous other matters.

Native American tribes are subject to various federal statutes and oversight by the Bureau of Indian Affairs and Bureau of Land Management. However, each Native American tribe is a sovereign nation and has the right to enact and enforce certain other laws and regulations entirely independent from federal, state and local statutes and regulations, as long as they do not supersede or conflict with such federal statutes. These tribal laws and regulations include various fees, taxes, requirements to employ Native American tribal members and numerous other conditions that apply to lessees, operators and contractors conducting operations within the boundaries of a Native American reservation. Further, lessees and operators within a Native American reservation are subject to the Native American tribal court system, unless there is a specific waiver of sovereign immunity by the Native American tribe allowing resolution of disputes between the Native American tribe and those lessees or operators to occur in federal or state court.

Therefore, we are subject to various laws and regulations pertaining to Native American tribal surface ownership, Native American oil and gas leases, fees, taxes and other burdens, obligations and issues unique to oil and gas ownership and operations within Native American reservations. One or more of these requirements, or delays in obtaining necessary approvals or permits pursuant to these regulations, may increase our costs of doing business on Native American tribal lands and have an impact on the economic viability of any well or project on those lands.

Employees

As of January 27, 2015, we had 202 employees of whom 140 work in our Denver office and 62 work in our field offices. We also contract for the services of independent consultants involved in land, regulatory, accounting, financial and other disciplines as needed. None of our employees are represented by labor unions or covered by any collective bargaining agreement. We believe that our relations with our employees are good.

Offices

As of December 31, 2014, we leased approximately 81,833 square feet of office space in Denver, Colorado at 1099 18th Street, where our principal offices are located. The lease for our Denver office expires in March 2019. We also own field offices in Roosevelt, Utah and Greeley, Colorado. We believe that our facilities are adequate for our current operations and that we can obtain additional leased space if needed.

Website and Code of Business Conduct and Ethics

We make available free of charge through our website our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to those reports as soon as reasonably practicable after such material is electronically filed with or furnished to the SEC via EDGAR and posted at http://www.sec.gov. Additionally, our Code of Business Conduct and Ethics, which includes our code of ethics for senior financial management, Corporate Governance Guidelines and the charters of our Audit Committee, Compensation Committee, Reserves and EHS Committee and Nominating and Corporate Governance Committee are posted on our website at http://www.billbarrettcorp.com and are available in print free of charge to any stockholder who requests them. Requests should be sent by mail to our corporate secretary at our principal office at 1099 18th Street, Suite 2300, Denver, Colorado 80202. We intend to disclose on our website any amendments or waivers to our Code of Business Conduct and Ethics that are required to be disclosed pursuant to Item 5.05 of Form 8-K. This Annual Report on Form 10-K and our website contain information provided by other sources that we believe are reliable. We cannot assure you that the information obtained from other sources is accurate or complete. No information on our website is incorporated by reference herein or deemed to be part of this Annual Report on Form 10-K.

Annual CEO Certification

As required by New York Stock Exchange rules, on May 19, 2014, we submitted an annual certification signed by our Chief Executive Officer certifying that he was not aware of any violation by us of New York Stock Exchange corporate governance listing standards as of the date of the certification.

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 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 that we currently consider immaterial also may adversely affect our Company.

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

Our drilling efforts and our well operations may not be profitable or achieve our targeted returns.

We have acquired significant amounts of proved and unproved property in order to attempt to further our exploration and development efforts. Drilling and production activities are subject to many risks, including the risk that no commercially productive reservoirs will be discovered. We acquire proved and unproved properties and lease undeveloped acreage that we believe will enhance our growth potential and increase our earnings over time. From time to time, we may seek industry partners to help mitigate our risk on certain exploration prospects. We cannot guarantee that all prospects will be economically viable or that we will not abandon our initial investments. Additionally, there can be no assurance that proved or unproved property acquired by us or undeveloped acreage leased by us will be profitably developed, that new wells drilled by us in prospects that we pursue will be productive, that we will recover all or any portion of our investment in such proved or unproved property or wells, or that we will succeed in bringing on additional partners.

Drilling for oil, natural gas and NGLs may involve unprofitable efforts, not only from dry wells but also from wells that are productive but do not produce sufficient commercial quantities to cover the drilling, operating and other costs. In addition, even a commercial well may have production that is less, or costs that are greater than we projected. The cost of drilling, completing and operating a well is often uncertain, and many factors can adversely affect the economics of a well or property. Drilling operations may be curtailed, delayed or canceled as a result of unexpected drilling conditions, equipment failures or accidents, shortages of equipment or personnel, environmental issues and for other reasons. We rely to a significant extent on seismic data and other advanced technologies in identifying unproved property prospects and in conducting our exploration activities. The seismic data and other technologies we use do not allow us to know conclusively, prior to acquisition of unproved property or drilling a well, whether oil, natural gas or NGLs are present or may be produced economically. The use of seismic data and other technologies also requires greater pre-drilling expenditures than traditional drilling strategies. Drilling results in our plays may be more uncertain than in other plays that are more mature and have longer established drilling and production histories, and we can provide no assurance that drilling and completion techniques that have proven to be successful in other formations to maximize recoveries will be ultimately successful when used in our prospects. As a result, we may incur future dry hole costs and or impairment charges due to any of these factors.

Oil and gas prices are volatile and a decline in oil, natural gas and natural gas liquids prices can significantly affect our financial results, impede our growth and result in downward adjustments in our estimated proved oil and gas reserves.

Our revenue, profitability and cash flow depend upon the prices for oil, natural gas and NGLs. The markets for these commodities are very volatile, based on supply and demand, and even relatively modest drops in prices can significantly affect our financial results and impede our growth. Changes in oil, natural gas and NGLs prices have a significant impact on the value of our reserves and on our cash flow. Prices for oil, natural gas and NGLs may fluctuate widely in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors that are beyond our control, such as:

- the domestic and foreign supply of oil, natural gas and NGLs;
- domestic and foreign governmental regulations;
- variations between product prices at sales points and applicable index prices;
- political and economic conditions in oil producing countries, including the Middle East and South America;
- the ability and willingness of members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- weather conditions;
- technological advances affecting energy consumption;
- proximity and capacity of oil and gas pipelines, refineries and other transportation and processing facilities; and
- the price and availability of alternative fuels.

Lower oil, natural gas and NGLs prices may not only decrease our revenues on a per unit basis, but also may reduce the amount of oil, natural gas and NGLs that we can produce economically. This may result in our having to make substantial downward adjustments to our estimated proved reserves. If this occurs or if our estimates of development costs increase, production data factors change or our exploration or development results deteriorate, successful efforts accounting rules may require us to write down or impair, as a non-cash charge to earnings, the carrying value of our oil and natural gas properties. We are required to perform impairment tests on our assets whenever events or changes in circumstances lead to a reduction of the estimated useful life or estimated future cash flows that would indicate that the carrying amount may not be recoverable or whenever management’s plans change with respect to those assets.

The severe decline in oil prices that occurred late in 2014, which has continued into 2015, has increased the volatility and amplitude of the other risks facing us as described in this report and has impacted our unit price and may have an impact on our business and financial condition. If oil prices remain low for an extended period of time, drilling in our DJ and Uinta Oil projects may become uneconomic, which could affect future drilling plans and growth rates. Low commodity prices impact our revenue, which we partially mitigate with our hedging program. Continued low commodity prices make it more challenging to hedge production at higher price levels. Lower sustained commodity prices or additional commodity price declines may lead to additional property impairment in future periods, which could have a material adverse effect on our results of operations in the period taken.

Substantially all of our producing properties are located in the Rocky Mountains, making us vulnerable to risks associated with operating in one major geographic area.

Our operations have been focused on the Rockies, which means our current producing properties and new drilling opportunities are geographically concentrated in that area. Because our operations are not as diversified geographically as many of our competitors, the success of our operations and our profitability may be disproportionately exposed to the effect of any regional events, including fluctuations in prices of oil, natural gas and NGLs produced from the wells in the region, natural disasters, restrictive governmental regulations, transportation capacity constraints, weather, curtailment of production or interruption of transportation and processing, and any resulting delays or interruptions of production from existing or planned new wells.

We are subject to complex federal, state, tribal, local and other laws and regulations that could adversely affect the cost, manner or feasibility of doing business and the recording of proved reserves.

Our exploration, development, production and marketing operations are subject to extensive environmental regulation at the federal, state and local levels including those governing emissions to air, wastewater discharges, hazardous and solid wastes, remediation of contaminated soil and groundwater, protection of surface and groundwater, land reclamation and preservation of natural resources. In addition, a portion of our leases in the Uinta Basin are, and some of our future leases may be, regulated by tribal authorities. Under these laws and regulations, we could be held liable for personal injuries, property damage (including site clean-up and restoration costs) and other damages. Failure to comply with these laws and regulations may also result in the suspension or termination of our operations and subject us to administrative, civil, and criminal penalties, including the assessment of natural resource damages. Environmental and other governmental laws and regulations also increase the costs to plan, design, drill, install, operate and abandon oil and natural gas wells and related facilities. Moreover, public interest in environmental protection has increased in recent years, and environmental organizations have opposed, with some success, certain drilling projects.

Our success depends on key members of our management and our ability to attract and retain experienced technical and other professional personnel.

Our future success depends to a large extent on the services of our key employees. The loss of one or more of these individuals could have a material adverse effect on our business. Furthermore, competition for experienced technical and other professional personnel remains strong. If we cannot retain our current personnel or attract additional experienced personnel, our ability to compete could be adversely affected. Also, the loss of experienced personnel could lead to a loss of technical expertise.

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, natural gas and NGLs production depends on a number of factors, including the demand for and supply of oil and natural gas and the proximity of our 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, processing facilities and refineries owned and operated by third parties. Our Uinta oil production has a high paraffin content which limits the number of refiners able to purchase it as feedstock. We may be required to shut in wells for a lack of a market or because of inadequacy or unavailability of natural gas pipeline, gathering system capacity or processing facilities. If that were to occur, we would be unable to realize revenue from those wells until production arrangements were made to deliver the production to market.

We may incur substantial losses and be subject to substantial liability claims as a result of our oil and gas operations. In addition, 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 or under-insured events could materially and adversely affect our business, financial condition or results of operations. Our oil and natural gas exploration and production activities, including well stimulation and completion activities such as hydraulic fracturing, 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 uncontrollable flows of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater contamination;
- abnormally pressured or structured formations;
- mechanical difficulties, such as stuck oilfield drilling and service tools and casing collapse;
- fires, explosions and ruptures of pipelines;
- 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 and equipment;
- damage to natural resources due to underground migration of hydraulic fracturing fluids or other fluids or gases;
- pollution and other environmental damage, including spillage or mishandling of recovered hydraulic fracturing fluids and produced water;
- regulatory investigations and penalties;
- suspension of our operations; and
- repair and remediation costs.

We have elected, and may in the future elect, not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. For example, we do not carry business interruption insurance for these reasons. In addition, pollution and environmental risks generally are not fully insurable. The occurrence of an event that is not covered or not fully covered by insurance could have a material adverse effect on our production, revenues and results of operations and overall financial condition.

Our operations require substantial capital and we may be unable to obtain needed capital or financing on satisfactory terms or at all, which could lead to a loss of properties and a decline in our oil, natural gas and NGL reserves.

The oil and gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures in our business and operations for the development, production and acquisition of oil, natural gas and NGL reserves. To date, we have financed capital expenditures primarily with sales of our equity and debt securities, proceeds from bank borrowings, sales of properties and cash generated by operations. We intend to finance our capital expenditures with cash flow from operations and our existing financing arrangements. Our cash flow from operations and access to capital is subject to a number of variables, including:

- our proved reserves;
- the level of oil, natural gas and NGLs we are able to produce from existing wells;
- the prices at which oil, natural gas and NGLs are sold;
- the costs required to operate production;
- our ability to acquire, locate and produce new reserves;
- global credit and securities markets;
- the ability and willingness of lenders and investors to provide capital and the cost of that capital; and
- the interest of buyers in our properties and the price they are willing to pay for properties.

If our revenues or the borrowing base under our credit facility decreases as a result of lower oil, natural gas and NGLs 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 or planned levels. We may, from time to time, need to seek additional financing. Our credit facility and senior note indentures place certain restrictions on our ability to obtain new financing. There can be no assurance as to the availability or terms of any additional financing.

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 available under our credit facility is not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to exploration and development of our prospects, which in turn could lead to a possible loss of properties and a decline in our oil, natural gas and NGLs reserves as well as our revenues and results of operations.

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

Our management has specifically identified and scheduled drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. These identified drilling locations represent a significant part of our strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including the availability of capital, seasonal conditions, regulatory approvals, oil, natural gas and NGLs 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, natural gas and NGLs from these or any other potential drilling locations. As such, our actual drilling activities may differ materially from those presently identified, which could adversely affect our business.

Competition in the oil and gas industry is intense, which may adversely affect our ability to succeed.

The oil and gas industry is intensely competitive, and we compete with other companies that have greater resources. Many of these companies not only explore for, develop and produce oil, natural gas and NGLs, but also carry on midstream and refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies are able to pay more for producing oil, natural gas and NGLs properties and exploration and development prospects or define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, these companies have a greater ability to continue exploration activities during periods of low oil, natural gas and NGLs market prices. Our larger or integrated competitors are better able than we are to absorb the burden of existing and any changes to federal, state, local and Native American tribal laws and regulations, which could adversely affect our competitive position. Our ability to acquire additional properties and to discover reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, because we have fewer financial and human resources than many companies in our industry, we may be at a disadvantage in bidding for producing properties and exploration and development prospects.

The ability of our lenders to fund their lending obligations under our revolving credit facility may be limited, which would affect our ability to fund our operations.

Our revolving credit facility has commitments from 17 lenders. If credit markets become turbulent as a result of an economic downturn, delayed economic recovery, lower commodity prices or other factors, our lenders may become more restrictive in their lending practices or may be unable to fund their commitments, which would limit our access to capital to fund our capital expenditures and operations. This would limit our ability to generate revenues as well as limit our projected production and reserves growth, leading to declining production and potentially losses.

A U.S. and global economic downturn could have a material adverse effect on our business and operations.

Any or all of the following may occur as a result if a crisis arises in the global financial and securities markets and resulting economic downturn:

- The economic slowdown could lead to lower demand for oil and natural gas by individuals and industries, which in turn has resulted and could continue to result in lower prices for the oil and natural gas sold by us, lower revenues and possibly losses. This is exacerbated by increases in oil and gas supply resulting from increases in U.S. oil and gas production.
- The lenders under our revolving credit facility may become more restrictive in their lending practices or unable or unwilling to fund their commitments, which would limit our access to capital to fund our capital expenditures and operations. This would limit our ability to generate revenues as well as limit our projected production and reserves growth, leading to declining production and possibly losses.
- We may be unable to obtain additional debt or equity financing, which would require us to limit our capital expenditures and other spending. This would lead to lower production levels and reserves than if we were able to spend more than our cash flow. Financing costs may significantly increase as lenders may be reluctant to lend without receiving higher fees and spreads.
- The losses incurred by financial institutions as well as the insolvency of some financial institutions heightens the risk that a counterparty to our hedge arrangements could default on its obligations. These losses and the possibility of a counterparty declaring bankruptcy or being placed in conservatorship or receivership may affect the ability of the counterparties to meet their obligations to us on hedge transactions, which could reduce our revenues from hedges at a time when we are also receiving a lower price for our natural gas and oil sales. As a result, our financial condition could be materially, adversely affected.

- Our credit facility bears floating interest rates based on the London Interbank Offer Rate, or LIBOR. As banks were reluctant to lend to each other to avoid risk, LIBOR increased to unprecedented spread levels in 2008. Such increases caused and may in the future cause higher interest expense for unhedged levels of LIBOR-based borrowings.
- Our credit facility requires the lenders to redetermine our borrowing base semi-annually. The redeterminations are based on our proved reserves and hedge position based on price assumptions that our lenders require us to use to calculate reserves pursuant to the credit facility. The lenders could reduce their price assumptions used to determine reserves for calculating our borrowing base due to lower commodities and futures prices and our borrowing base could be reduced. This would reduce our funds available to borrow. In addition, the lenders can request an interim redetermination.
- Bankruptcies of financial institutions or illiquidity of money market funds may limit or delay our access to our cash equivalent deposits, causing us to lose some or all of those funds or to incur additional costs to borrow funds needed on a short-term basis that were previously funded from our money market deposits.
- Bankruptcies of purchasers of our oil and natural gas could lead to the delay or failure of us to receive the revenues from those sales.

Our estimated reserves are based on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these assumptions will materially affect the quantities of our reserves.

Underground accumulations of oil, natural gas and NGLs cannot be measured in an exact way. Oil, natural gas and NGLs reserve engineering requires estimates of underground accumulations of oil, natural gas and NGLs and assumptions concerning future oil, natural gas and NGLs prices, production levels and operating and development costs. As a result, estimated quantities of proved reserves and projections of future production rates and the timing of development expenditures may be incorrect.

Our estimates of proved reserves are determined at prices and costs at the date of the estimate. Any significant variance from these prices and costs could greatly affect our estimates of reserves. We prepare our own estimates of proved reserves, which are audited by independent third party petroleum engineers. Over time, our internal engineers may make material changes to reserves estimates taking into account the results of actual drilling, testing and production. For additional information about these risks and their impact on our reserves, see “Items 1 and 2. Business and Properties—Oil and Gas Data—Proved Reserves” and “Supplementary Information to Consolidated Financial Statements—Supplementary Oil and Gas Information (unaudited)—Analysis of Changes in Proved Reserves” in this Annual Report on Form 10-K.

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

Producing oil, natural gas and NGL reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. The rate of decline will change if production from our existing wells declines in a different manner than we have estimated and can change under other circumstances. Thus, our future oil, natural gas and NGL reserves and production and, therefore, our cash flow and income are highly dependent upon our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire additional reserves to replace our current and future production at acceptable costs.

Properties that we buy may not produce as projected and we may be unable to determine reserve potential, identify liabilities associated with the properties or obtain protection from sellers against them.

One of our strategies is to capitalize on opportunistic acquisitions of oil, natural gas and NGLs reserves. Our reviews of acquired properties are inherently incomplete, because it generally is not feasible to review in depth every individual property involved in each acquisition. Ordinarily, we will focus our review efforts on the higher value properties and will sample the remaining properties for reserve potential. However, even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit us to become sufficiently familiar with the properties to assess fully their deficiencies and potential. Inspections may not always be performed on every well, and environmental problems, such as ground water contamination, are not necessarily observable even when an inspection is undertaken. Even when problems are identified, we often assume certain environmental and other risks and liabilities in connection with acquired properties.

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

To achieve a more predictable cash flow and to reduce our exposure to adverse fluctuations in the prices of commodities, we currently, and will likely in the future, enter into hedging arrangements for a portion of our production revenues. Hedging arrangements for a portion of our production revenues expose us to the risk of financial loss in some circumstances, including when:

- there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received;
- there is a change in the mark to market value of our derivatives; or
- the counterparty to the hedging contract defaults on its contractual obligations.

In addition, these types of hedging arrangements limit the benefit we would receive from increases in commodities prices and may expose us to cash margin requirements if we hedge with counterparties who are not parties to our credit facility.

Our counterparties are financial institutions that are lenders under our credit facility or affiliates of such lenders. The risk that a counterparty may default on its obligations was heightened by the financial sector crisis of 2008-2009, and losses incurred by many banks and other financial institutions, including some of our counterparties or their affiliates. These losses may affect the ability of the counterparties to meet their obligations to us on hedge transactions, which would reduce our revenues from hedges at a time when we are also receiving a lower price for our production revenues, thus triggering the hedge payments. As a result, our financial condition could be materially adversely affected.

Federal legislation may decrease our ability, and increase the cost, to enter into hedge transactions.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (“Dodd-Frank”) was signed into law in July 2010. Dodd-Frank regulates derivative transactions, including our commodity derivative swaps. As a commercial end user using derivatives to manage commercial risks, we are exempt from posting collateral requirements and mandatory trading on a centralized exchange. We expect to be able to continue to trade with our counterparties, which all are or have been lenders or affiliates of lenders in our credit facility, albeit with a separate capitalized subsidiary of the lender. We expect that the cost to hedge will increase as a result of fewer counterparties in the market and the pass-through of increased capital costs of bank subsidiaries. Decreasing our ability to enter into hedging transactions would expose us to additional risks related to commodity price volatility and impair our ability to have certainty with respect to a portion of our cash flow, which could lead to decreases in capital spending and, therefore, decreases in future production and reserves.

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

Substantially all of our accounts receivable result from oil, natural gas and NGLs sales or joint interest billings to third parties in the energy industry. This concentration of customers and joint interest owners may impact our overall credit risk in that these entities may be similarly affected by changes in economic and other conditions. In addition, our oil, natural gas and NGLs hedging arrangements expose us to credit risk in the event of nonperformance by counterparties. An economic downturn, a delayed economic recovery and the European sovereign debt crisis further increase these risks.

We face risks related to rating agency downgrades.

If one or more rating agencies downgrades our outstanding debt, future debt issuance could become more difficult and more costly. Also, we may be required to provide collateral or other credit support to certain counterparties, which would increase our costs and limit our liquidity.

Our business could be negatively impacted by security threats, including cyber-security threats, and other disruptions.

As an oil and natural gas producer, we face various security threats, including cyber-security threats to gain unauthorized access to sensitive information or to render data or systems unusable, threats to the safety of our employees, threats to the security of our facilities and infrastructure or third party facilities and infrastructure, such as processing plants and pipelines, and threats from terrorist acts. Cyber-security attacks in particular are evolving and include but are not limited to, malicious software, attempts to gain unauthorized access to data, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information, corruption of data or mis-appropriating of assets. Although we utilize various procedures and controls to monitor and protect against these threats and to mitigate our exposure to such threats, there can be no assurance that these procedures and controls will be sufficient in preventing security threats from materializing. If any of these events were to materialize, they could lead to losses of sensitive information, critical infrastructure, personnel or capabilities, essential to our operations and could have a material adverse effect on our reputation, financial position, results of operations, or cash flows.

Risks Related to Our Common Stock

Provisions in our certificate of incorporation and bylaws and Delaware law make it more difficult to effect a change in control of us, which could adversely affect the price of our common stock.

Delaware corporate law and our current certificate of incorporation and bylaws contain provisions that could delay, defer or prevent a change in control of us or our management. These provisions include:

- giving the board the exclusive right to fill all board vacancies;
- requiring special meetings of stockholders to be called only by the board;
- requiring advance notice for stockholder proposals and director nominations;
- prohibiting stockholder action by written consent;

- prohibiting cumulative voting in the election of directors; and
- allowing for authorized but unissued common and preferred shares, including shares used in our shareholder rights plan.

These provisions also could discourage proxy contests and make it more difficult for our stockholders to elect directors and take other corporate actions that are opposed by our board. As a result, these provisions could make it more difficult for a third party to acquire us, even if doing so would benefit our stockholders, which may limit the price that investors are willing to pay in the future for shares of our common stock.

Risks Related to our Senior Notes, Convertible Notes, Lease Financing Obligations and Amended Credit Facility

We may not be able to generate enough cash flow to meet our debt obligations, including our obligations and commitments under our senior notes, our convertible senior notes, our lease financing obligations and our revolving credit facility.

We expect our earnings and cash flow could vary significantly from year to year due to the cyclical 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. In addition, our future cash flow may be insufficient to meet our debt obligations and commitments, including our 5% Convertible Senior Notes due 2028 (“Convertible Notes”), our 7.625% Senior Notes due 2019 (“7.625% Senior Notes”), our 7.0% Senior Notes due 2022 (“7.0% Senior Notes”), our lease financing obligations, and our revolving credit facility (“Amended Credit Facility”). 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 repay our debt. Many of these factors, such as oil and gas prices, economic and financial conditions in our industry and the global economy or competitive initiatives of our competitors, are beyond our control.

As of December 31, 2014, the total outstanding principal amount of our total indebtedness was approximately $829.0 million, and we had approximately $349.0 million in additional borrowing capacity under our Amended Credit Facility, which, if borrowed, would be secured debt effectively senior to the Senior Notes and Convertible Notes to the extent of the value of the collateral securing that indebtedness. The borrowing base is dependent on our proved reserves and was, as of December 31, 2014, $375.0 million based on our June 30, 2014 proved reserves, adjusted for the sale of our Piceance Basin properties, and hedge position. Our borrowing capacity is reduced by a $26.0 million letter of credit. As of December 31, 2014, we had no amounts outstanding under our Amended Credit Facility.

The borrowing base is set at the sole discretion of the lenders. Our next scheduled borrowing base redetermination is scheduled on or about April 1, 2015 based on proved reserves as of December 31, 2014 at updated bank price decks and hedge position. However, in the event of lower capital investment in our properties due to a sustained cycle of low commodity prices, we could see lower quantities of proved developed reserves which would, in combination with lower oil and gas commodity pricing, lead to lower borrowing bases.

If we do not generate enough cash flow from operations to satisfy our debt obligations, we may have to undertake one or more alternative financing plans, such as:

- refinancing or restructuring our debt;
- selling assets;

- reducing or delaying capital investments; or
- seeking to raise additional capital.

However, any alternative financing plans that we undertake, if necessary, may not allow us to meet our debt obligations. Our inability to generate sufficient cash flow to satisfy our debt obligations, including our obligations under the notes, or to obtain alternative financing, could materially and adversely affect our business, financial condition, results of operations and prospects.

Our debt could have important consequences. For example, it could:

- increase our vulnerability to general adverse economic and industry conditions;
- limit our ability to fund future capital expenditures and working capital, to engage in future acquisitions or development activities, or to otherwise realize the value of our assets and opportunities fully because of the need to dedicate a substantial portion of our cash flow from operations to payments of interest and principal on our debt or to comply with any restrictive terms of our debt;
- limit our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate;
- impair our ability to obtain additional financing in the future; and
- place us at a competitive disadvantage compared to our competitors that have less debt.

In addition, if we fail to comply with the covenants or other terms of any agreements governing our debt, our lenders and holders of our convertible notes and our senior notes may have the right to accelerate the maturity of that debt and foreclose upon the collateral, if any, securing that debt. Realization of any of these factors could adversely affect our financial condition.

We may not be able to meet future debt obligations or debt service costs on our outstanding debt instruments in the event of a sustained down cycle in commodity prices.

Volatile oil, natural gas and NGLs prices can have a significant effect on our revenue, profitability and cash flows from operations. Even relatively modest declines in prices can significantly affect our financial results and impede our ability to meet existing debt obligations undertaken to finance the substantial capital required to successfully explore and produce economically viable oil and natural gas properties. Sustained low commodity prices may not allow us to generate sufficient cash flows to cover debt obligations in the future (our principal debt obligations become due starting in 2019) and/or debt service charges in the near term.

Restrictions in our existing and future debt agreements could limit our growth and our ability to respond to changing conditions.

Our Amended Credit Facility contains a number of significant covenants in addition to covenants restricting the incurrence of additional debt. Our Amended Credit Facility requires us, among other things, to maintain certain financial ratios or reduce our debt. These restrictions also limit our ability to obtain future financings to withstand a future downturn in our business or the economy in general, or to otherwise conduct necessary corporate activities. We may also be prevented from taking advantage of business opportunities that arise because of the limitations that the restrictive covenants under the indenture governing the notes and our Amended Credit Facility impose on us.

Our Amended Credit Facility limits the amounts we can borrow up to a borrowing base amount, which the lenders, in their sole discretion, determine based upon projected revenues from the oil and natural gas properties securing our loan. The lenders can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under our Amended Credit Facility. Any increase in the borrowing base requires the consent of the lenders holding 98% of the commitments. If the required lenders do not agree on an increase, then the borrowing base will be the lowest borrowing base acceptable to the required number of lenders. Outstanding borrowings in excess of the borrowing base must be repaid immediately or we must pledge other oil and natural gas properties as additional collateral. We do not currently have any substantial unpledged properties, and we may not have the financial resources in the future to make mandatory principal prepayments required under the Amended Credit Facility.

A breach of any covenant in our Amended Credit Facility or the agreements and indentures governing our other indebtedness would result in a default under that agreement or indenture after any applicable grace periods. A default, if not waived, could result in acceleration of the debt outstanding under the agreement and in a default with respect to, and an acceleration of, the debt outstanding under other debt agreements. The accelerated debt would become immediately due and payable. If that occurs, we may not be able to make all of the required payments or borrow sufficient funds to refinance such debt or take other actions to pay accelerated debt. Even if new financing were available at that time, it may not be on terms that are acceptable to us.

Risks Relating to Tax

We may incur more taxes if certain federal income tax deductions currently available with respect to oil and natural gas exploration and development are eliminated as a result of future legislation.

The Administration has proposed eliminating certain key U.S. federal income tax deductions and credits currently available to oil and natural gas exploration and production companies. These changes include, but are not limited to:

- the repeal of the percentage depletion allowance for oil, natural gas and NGL properties;
- the elimination of current deductions for intangible drilling and development costs;
- the elimination of the deduction for certain U.S. production activities; and
- an extension of the amortization period for certain geological and geophysical expenditures.

It is unclear whether any of the foregoing changes will be enacted or how soon any such changes could become effective. Any such change could negatively impact our financial condition and results of operations by increasing the costs we incur, which in turn could make it uneconomic to drill some prospects if commodity prices are not sufficiently high, resulting in lower revenues and decreases in production and reserves.

Item 1B. Unresolved Staff Comments.

Not applicable.

Item 3. Legal Proceedings.

We are not a party to any material pending legal or governmental proceedings, other than ordinary routine litigation incidental to our business. While the ultimate outcome and impact of any proceeding cannot be predicted with certainty, our management believes that the resolution of any proceeding will not have a material adverse effect on our financial condition or results of operations.

Item 4. Mine Safety Disclosures.

Not applicable.

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 under the symbol "BBG".

The range of high and low sales prices for our common stock for the two most recent fiscal years as reported by the New York Stock Exchange was as follows:

	High	Low
2014		
First Quarter	$29.73	$21.85
Second Quarter	29.35	21.50
Third Quarter	27.39	20.59
Fourth Quarter	22.51	7.54
2013		
First Quarter	$21.64	$15.50
Second Quarter	24.23	17.78
Third Quarter	25.47	20.34
Fourth Quarter	30.69	24.08

On January 27, 2015, the closing sales price for our common stock as reported by the NYSE was $10.82 per share.

Holders. On January 27, 2015, the number of holders of record of our common stock was 110.

Dividends. We have not paid any cash dividends since our inception. Because we anticipate that all earnings will be retained for the development of our business and our debt agreements prohibit the payment of cash dividends, we do not expect that any cash dividends will be paid on our common stock for the foreseeable future.

Unregistered Sales of Securities. There were no sales of unregistered equity securities during the year ended December 31, 2014.

Issuer Purchases of Equity Securities. The following table contains information about our acquisitions of equity securities during the three months ended December 31, 2014:

Period	Total Number of Shares Purchased (1)	Weighted Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares that May Yet be Purchased Under the Plans or Programs
October 1 - 31, 2014	6,432	$17.19	0	0
November 1 - 30, 2014	2,779	$13.98	0	0
December 1 - 31, 2014	7,363	$ 9.81	0	0
Total	16,574	$13.38	0	0

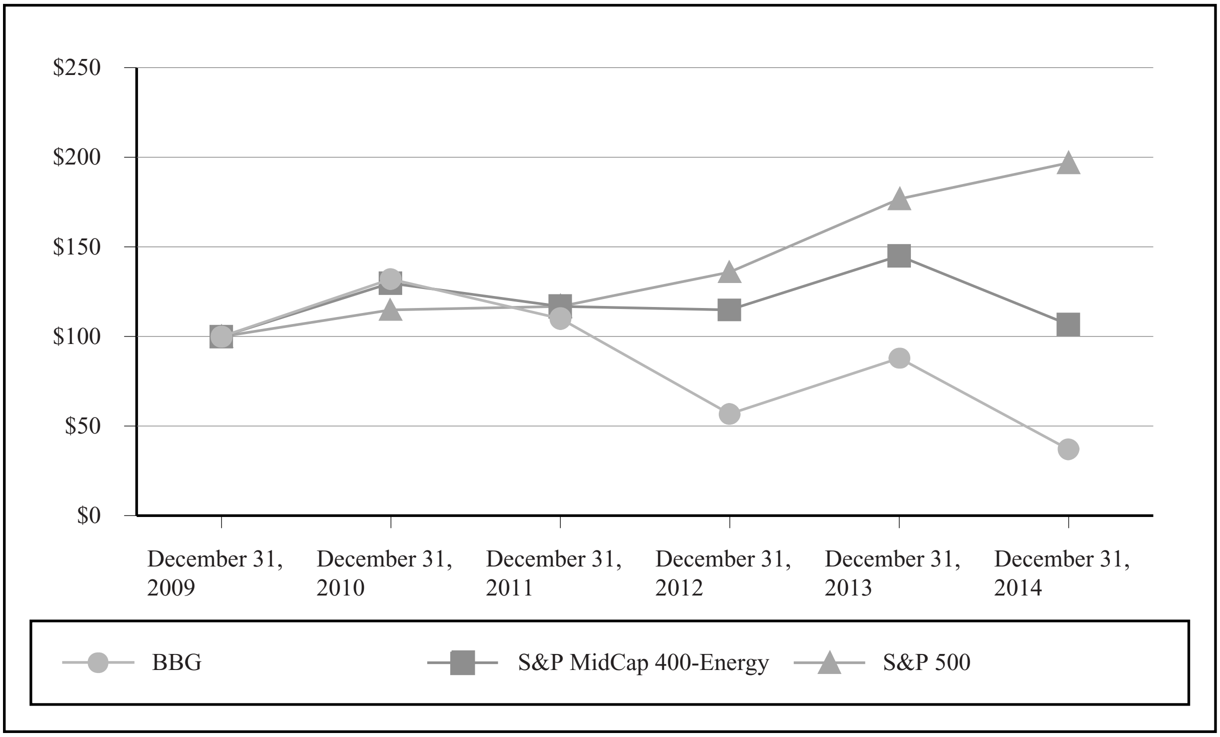
(1) Represents shares delivered by employees to satisfy the exercise price of stock options and tax withholding obligations in connection with the exercise of stock options and shares withheld from

employees to satisfy tax withholding obligations in connection with the vesting of shares of restricted common stock issued pursuant to our employee incentive plans.

Stockholder Return Performance Presentation

As required by applicable rules of the SEC, the performance graph shown below was prepared based upon the following assumptions:

1. $100 was invested in our common stock on December 31, 2009, and $100 was invested in each of the Standard & Poors 500 Index and the Standard & Poors MidCap 400 Index-Energy Sector at the closing price on December 31, 2009.
2. Dividends are reinvested on the ex-dividend dates.



	December 31, 2009	December 31, 2010	December 31, 2011	December 31, 2012	December 31, 2013	December 31, 2014
BBG	$100	$132	$110	$ 57	$ 88	$ 37
S&P MidCap 400-Energy	100	130	117	115	145	107
S&P 500	100	115	117	136	177	197

Item 6. Selected Financial Data.

The following table presents our selected historical financial data for the years ended December 31, 2014, 2013, 2012, 2011 and 2010. Future results may differ substantially from historical results because of changes in oil and gas prices, production increases or declines and other factors. This information should be read in conjunction with the consolidated financial statements and notes thereto and “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations” presented elsewhere in this Annual Report on Form 10-K.

Selected Historical Financial Information

The consolidated statement of operations information for the years ended December 31, 2014, 2013 and 2012 and the balance sheet information as of December 31, 2014 and 2013 are derived from our audited consolidated financial statements included elsewhere in this report. The consolidated statement of operations information for the years ended December 31, 2011 and 2010 and the balance sheet information at December 31, 2012, 2011 and 2010 are derived from audited consolidated financial statements that are not included in this report. The information in this table should be read in conjunction with the consolidated financial statements and accompanying notes and other financial data included herein.

	Year Ended December 31,				
	2014	2013	2012	2011	2010
	(in thousands, except per share data)				
Statement of Operations Data:					
Operating and Other Revenues:					
Oil, gas and NGL production [1]	$ 464,137	$ 565,555	$ 700,639	$ 780,751	$ 708,452
Other	8,154	2,538	(444)	4,873	591
Total operating and other revenues	472,291	568,093	700,195	785,624	709,043
Operating Expenses:					
Lease operating expense	60,308	70,217	72,734	56,603	52,040
Gathering, transportation and processing expense	35,437	67,269	106,548	93,423	69,089
Production tax expense	31,333	27,172	25,513	37,498	32,738
Exploration expense	453	337	8,814	3,645	9,121
Impairment, dry hole costs and abandonment expense	46,881	238,398	67,869	117,599	44,664
Loss on divestitures	100,407	—	—	—	—
Depreciation, depletion and amortization expense	235,805	279,775	326,842	288,421	260,665
Unused commitments	4,434	—	—	—	—
General and administrative expense [2]	41,981	49,069	52,222	47,744	40,884
Non-cash stock-based compensation expense [2]	11,380	15,833	16,444	19,036	16,908
Total operating expenses	568,419	748,070	676,986	663,969	526,109
Operating Income (Loss)	(96,128)	(179,977)	23,209	121,655	182,934
Other Income and Expense:					
Interest income and other income (expense)	1,294	1,646	155	(397)	402
Interest expense	(69,623)	(88,507)	(95,506)	(58,616)	(44,302)
Commodity derivative gain (loss)	197,447	(23,068)	72,759	(14,263)	(10,579)
Gain (loss) on extinguishment of debt	—	(21,460)	1,601	—	—
Total other income and expense	129,118	(131,389)	(20,991)	(73,276)	(54,479)
Income (Loss) before Income Taxes	32,990	(311,366)	2,218	48,379	128,455
Provision for (Benefit from) Income Taxes	17,909	(118,633)	1,636	17,672	47,953
Net Income (Loss)	$ 15,081	$(192,733)	$ 582	$ 30,707	$ 80,502
Net Income (Loss) per Common Share:					
Basic	$ 0.31	$ (4.06)	$ 0.01	$ 0.66	$ 1.78
Diluted	$ 0.31	$ (4.06)	$ 0.01	$ 0.65	$ 1.75
Weighted average common shares outstanding, basic	48,010.7	47,496.9	47,194.7	46,535.6	45,217.6
Weighted average common shares outstanding, diluted	48,435.7	47,496.9	47,354.0	47,236.7	45,877.4

	Year Ended December 31,				
	2014	2013	2012	2011	2010
	(in thousands)				
Selected Cash Flow and Other Financial Data:					
Net income (loss)	$ 15,081	$(192,733)	$ 582	$ 30,707	$ 80,502
Depreciation, depletion, impairment and amortization	275,988	506,326	364,190	388,699	276,281
Other non-cash items	(59,970)	(32,600)	29,281	55,102	101,079
Change in assets and liabilities	30,618	(15,728)	(5,617)	4,840	(10,674)
Net cash provided by operating activities	$261,717	$ 265,265	$388,436	$479,348	$447,188
Capital expenditures (3)(4)(5)	$569,312	$ 474,031	$962,573	$987,341	$473,268

(1) Oil, gas and NGL production revenues include the effects of cash flow hedging transactions.

(2) Non-cash stock-based compensation expense is presented herein as a separate line item but is combined with general and administrative expense in the Consolidated Statements of Operations for a total of $53.4 million, $64.9 million, $68.7 million, $66.8 million and $57.8 million for the years ended December 31, 2014, 2013, 2012, 2011 and 2010, respectively. This separate presentation is a non-GAAP measure. Management believes the separate presentation of the non-cash component of general and administrative expense is useful because the cash portion provides a better understanding of our required cash for general and administrative expense. We also believe that this disclosure allows for a more accurate comparison to our peers, which may have higher or lower non-cash stock-based compensation expense.

(3) Excludes future reclamation liabilities of negative $8.6 million, negative $6.6 million, $7.5 million, $12.1 million and $1.3 million for the years ended December 31, 2014, 2013, 2012, 2011 and 2010, respectively, and includes exploration, dry hole and abandonment costs, which are expensed under successful efforts accounting, of $7.2 million, $12.2 million, $39.3 million, $21.0 million and $38.2 million for the years ended December 31, 2014, 2013, 2012, 2011 and 2010, respectively. Also includes furniture, fixtures and equipment costs of $3.7 million, $1.3 million, $6.9 million, $8.9 million and $2.1 million for the years ended December 31, 2014, 2013, 2012, 2011 and 2010, respectively.

(4) Not deducted from the amount are $555.4 million, $306.3 million, $325.3 million, $2.0 million and $2.9 million of proceeds received principally from the sale of interests in oil and gas properties during the years ended December 31, 2014, 2013, 2012, 2011 and 2010, respectively.

(5) Capital expenditures for the year ended December 31, 2014 exclude $79.0 million related to property acquired through property exchanges.

	As of December 31,				
	2014	2013	2012	2011	2010
			(in thousands)		
Balance Sheet Data:					
Cash and cash equivalents	$ 165,904	$ 54,595	$ 79,445	$ 57,331	$ 58,690
Other current assets	260,201	102,652	148,894	189,012	148,958
Oil and natural gas properties, net of accumulated depreciation, depletion, amortization and impairment	1,730,172	2,184,183	2,584,979	2,383,196	1,796,288
Other property and equipment, net of depreciation	13,715	18,313	26,358	23,568	15,531
Oil and natural gas properties held for sale, net of accumulated depreciation, depletion, amortization and impairment	9,234	—	—	—	—
Other assets	65,258	21,770	29,773	34,823	19,033
Total assets	$2,244,484	$2,381,513	$2,869,449	$2,687,930	$2,038,500
Current liabilities	$ 264,687	$ 192,719	$ 213,133	$ 233,198	$ 165,957
Long-term debt	803,222	979,082	1,156,654	882,240	404,399
Other long-term liabilities	147,087	203,994	316,887	353,654	327,182
Stockholders' equity	1,029,488	1,005,718	1,182,775	1,218,838	1,140,962
Total liabilities and stockholders' equity	$2,244,484	$2,381,513	$2,869,449	$2,687,930	$2,038,500

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

Introduction

The following discussion and analysis should be read in conjunction with the "Selected Financial Data" and the accompanying consolidated financial statements and related notes included elsewhere in this Annual Report on Form 10-K. This section and other parts of this Annual Report on Form 10-K contain forward-looking statements that involve risks and uncertainties. See the "Cautionary Note Regarding Forward-Looking Statements" at the beginning of this Annual Report on Form 10-K. Forward-looking statements are not guarantees of future performance and our actual results may differ significantly from the results discussed in the forward-looking statements. Factors that might cause such differences include, but are not limited to, those discussed in "Items 1 and 2. Business and Properties—Business—Operations—Environmental Matters and Regulation;" "Items 1 and 2. Business and Properties—Business—Operations—Other Regulation of the Oil and Gas Industry;" and "Item 1A. Risk Factors" above, all of which are incorporated herein by reference. We assume no obligation to revise or update any forward-looking statements for any reason, except as required by law.

Overview

We develop oil and natural gas in the Rocky Mountain region of the United States. We seek to build stockholder value by delivering profitable growth in cash flow, reserves and production through the development of oil and natural gas assets. In order to deliver profitable growth, we allocate capital to our highest return assets, concentrate expenditures on exploiting our core assets, maintain capital discipline and optimize operations while upholding high-level standards for health, safety and the environment. Substantially all of our revenues are generated through the sale of oil and natural gas production and NGL recovery at market prices.

We were formed in January 2002 and are incorporated in the State of Delaware. In December 2004, we completed our initial public offering of 14,950,000 shares of our common stock at a price to the public of $25.00 per share.

We are committed to developing and producing oil and natural gas in a responsible and safe manner. Our employees work diligently with regulatory agencies, as well as environmental, wildlife and community organizations, to ensure that exploration and development activities meet stakeholders expectations and regulatory requirements.

While there are currently no unannounced agreements for the acquisition of any material businesses or assets, future acquisitions or dispositions could have a material impact on our financial condition and results of operations by increasing or decreasing our reserves, production and revenues as well as expenses and future capital expenditures. We currently anticipate that we would finance any future acquisitions with available borrowings under our Amended Credit Facility, sales of properties, other indebtedness, and/or debt, equity or equity-linked securities. Our prior acquisitions and capital expenditures were financed with a combination of cash on hand, funding from the sale of our equity securities, our Amended Credit Facility, other debt financing and cash flows from operations.

Beginning January 1, 2013, we modified our gas processing agreements with various processors to take title to NGLs resulting from the processing of our natural gas. Therefore, we report below reserve and production data for oil, natural gas and NGLs for periods after January 1, 2013. This is known as “three streams reporting”. For periods prior to January 1, 2013, we presented our production and reserve data for oil and natural gas, which included NGLs in the natural gas stream. This change impacts the comparability of 2013 and 2014 production and reserves with those reported for prior periods.

Because of our growth through acquisitions and, more recently, development of our properties and sales of properties in 2012, 2013 and 2014, our historical results of operations and period-to-period comparisons of these results and certain financial data may not be meaningful. In addition, past results are not indicative of future results.

The following table summarizes the estimated net proved reserves and related Standardized Measure for the years indicated. The Standardized Measure is not intended to represent the current market value of our estimated oil and natural gas reserves.

	Year Ended December 31,		
	2014	2013	2012
Estimated net proved reserves (MMBoe)	122.3	197.0	174.0
Standardized measure (1) (in millions)	$1,169.6	$1,377.5	$1,166.7

(1) December 31, 2014 reserves were based on average prices of $94.99 WTI for oil, $4.35 Henry Hub for natural gas and $39.65 for NGLs. December 31, 2013 reserves were based on average prices of $96.91 WTI for oil, $3.67 Henry Hub for natural gas and $39.75 for NGLs. December 31, 2012 reserves were based on average prices of $2.56 CIG for natural gas and $91.21 WTI for oil.

The following table summarizes the average sales prices received for oil, natural gas and NGLs, before the effects of hedging contracts, for the years indicated:

	Year Ended December 31,		
	2014	2013	2012
Oil (per Bbl)	$77.92	$82.61	$79.39
Natural gas (per Mcf) (1)	$ 4.78	$ 3.96	$ 4.00
NGLs (per Bbl) (1)	$31.55	$27.02	$ —

(1) Prior to 2013, NGL volumes and revenues were included within natural gas production data, which impacts the comparability for the period presented.

The following table summarizes the average sales prices received for oil, natural gas and NGLs, after the effects of hedging contracts, for the years indicated:

	Year Ended December 31,		
	2014	2013	2012
Oil (per Bbl)	$79.51	$82.38	$84.96
Natural gas (per Mcf) (1)	$ 4.45	$ 4.16	$ 5.07
NGLs (per Bbl) (1)	$31.51	$28.31	$ —

(1) Prior to 2013, NGL volumes and revenues were included within natural gas production data, which impacts the comparability for the period presented.

Commodity prices are inherently volatile and are influenced by many factors outside of our control. We plan our activities and capital budget using what we believe to be conservative sales price assumptions and our existing hedge position. Our strategic objective is to hedge 50% to 70% of our anticipated production on a forward 12-month to 18-month basis using a combination of swaps and other financial derivative instruments. We currently have hedged approximately 90% of our expected 2015 production at price levels that provide some economic certainty. We focus our efforts on increasing oil, natural gas and NGLs reserves and production while controlling costs at a level that is appropriate for long-term operations. Our future earnings and cash flows are dependent on our ability to manage our revenues and overall cost structure to a level that allows for profitable production.

Like all oil and gas exploration and production companies, we face the challenge of natural production declines. As initial reservoir pressures are depleted, oil, gas and NGLs production from a typical well naturally decreases. Thus, an oil and gas exploration and production company depletes part of its asset base with each unit of oil or natural gas it produces. We attempt to overcome this natural decline by drilling to find additional reserves and acquiring more reserves than we produce. Our future growth will depend on our ability to continue to add reserves in excess of production. We will maintain our focus on costs to add reserves through drilling and acquisitions as well as the costs necessary to produce such reserves. Our ability to add reserves through drilling is dependent on our capital resources and can be limited by many factors, including our ability to timely obtain drilling permits and regulatory approvals. See "– Trends and Uncertainties – Regulatory Trends" below. The permitting and approval process has been more difficult in recent years than in the past due to more stringent rules, such as those enacted by the COGCC in 2009, and increased activism from environmental and other groups, which has extended the time it takes us to receive permits and other necessary approvals. Because of our relatively small size and concentrated property base, we can be disproportionately disadvantaged by delays in obtaining or failing to obtain drilling approvals compared to companies with larger or more dispersed property bases. As a result, we may be less able to shift drilling activities to areas where permitting may be easier, and we have fewer properties over which to spread the costs related to complying with these regulations and the costs or foregone opportunities resulting from delays.

Results of Operations

Year Ended December 31, 2014 Compared with Year Ended December 31, 2013

The following table sets forth selected operating data for the periods indicated:

	Year Ended December 31,		Increase (Decrease)	
	2014	2013	Amount	Percent
	($ in thousands, except per unit data)			
Operating Results:				
Operating and Other Revenues				
Oil, gas and NGL production	$464,137	$565,555	$(101,418)	(18)%
Other	8,154	2,538	5,616	221%
Total operating and other revenues	$472,291	$568,093	$ (95,802)	(17)%
Operating Expenses				
Lease operating expense	$ 60,308	$ 70,217	$ (9,909)	(14)%
Gathering, transportation and processing expense	35,437	67,269	(31,832)	(47)%
Production tax expense	31,333	27,172	4,161	15%
Exploration expense	453	337	116	34%
Impairment, dry hole costs and abandonment expense	46,881	238,398	(191,517)	(80)%
Loss on divestitures	100,407	—	100,407	*nm
Depreciation, depletion and amortization	235,805	279,775	(43,970)	(16)%
Unused commitments	4,434	—	4,434	*nm
General and administrative expense (1)	41,981	49,069	(7,088)	(14)%
Non-cash stock-based compensation expense (1)	11,380	15,833	(4,453)	(28)%
Total operating expenses	$568,419	$748,070	$(179,651)	(24)%
Production Data:				
Oil (MBbls)	4,012	3,495	517	15%
Natural gas (MMcf)	21,744	52,685	(30,941)	(59)%
NGLs (MBbls)	1,476	2,199	(723)	(33)%
Combined volumes (MBoe)	9,112	14,475	(5,363)	(37)%
Daily combined volumes (Boe/d)	24,964	39,658	(14,694)	(37)%
Average Realized Prices (2):				
Oil (per Bbl)	$ 79.51	$ 82.38	$ (2.87)	(3)%
Natural gas (per Mcf)	4.45	4.16	0.29	7%
NGLs (per Bbl)	31.51	28.31	3.20	11%
Combined (per Boe)	50.73	39.35	11.38	29%
Average Costs (per Boe):				
Lease operating expense	$ 6.62	$ 4.85	$ 1.77	36%
Gathering, transportation and processing expense	3.89	4.65	(0.76)	(16)%
Production tax expense	3.44	1.88	1.56	83%
Depreciation, depletion and amortization	25.88	19.33	6.55	34%
General and administrative expense (3)	4.61	3.39	1.22	36%

* Not meaningful.

(1) Non-cash stock-based compensation expense is presented herein as a separate line item but is combined with general and administrative expense for a total of $53.4 million and $64.9 million for the years ended December 31, 2014 and 2013, respectively, in the Consolidated Statements of Operations. This separate presentation is a non-GAAP measure. Management believes the separate presentation of the non-cash component of general and administrative expense is useful because the cash portion provides a better understanding of our required cash for general and administrative expenses. We also believe that this disclosure allows for a more accurate comparison to our peers, which may have higher or lower expenses associated with stock-based grants.

(2) Average realized prices shown in the table are net of the effects of all settled commodity hedging transactions related to current period production.
(3) Excludes non-cash stock-based compensation expense as described in Note 1 above. This presentation is a non-GAAP measure. Average costs per Boe for general and administrative expense, including non-cash stock-based compensation expense, as presented in the Consolidated Statements of Operations, were $5.86 and $4.48 for the years ended December 31, 2014 and 2013, respectively.

Production Revenues and Volumes. Production revenues decreased to $464.1 million for the year ended December 31, 2014 from $565.6 million for the year ended December 31, 2013. The decrease in production revenues was primarily due to a 37% decrease in production volumes, offset by an increase in the average price per Boe. The decrease in production volumes reduced production revenues by approximately $273.3 million, while the increase in average prices increased production revenues by approximately $171.8 million.

We discontinued hedge accounting as of January 1, 2012. All accumulated gains or losses related to the discontinued cash flow hedges were recorded in accumulated other comprehensive income ("AOCI") as of January 1, 2012 and remained in AOCI until the underlying transaction occurred. As the underlying transaction occurred, these gains or losses were reclassified from AOCI into oil, gas and NGL production revenues. The amount reclassified to oil, gas and NGL production revenues was a gain of $1.1 million and $7.5 million for the years ended December 31, 2014 and 2013, respectively. All cash flow hedge accounting transactions were completed as of December 31, 2014.

Total production volumes of 9.1 MMBoe for the year ended December 31, 2014 decreased from 14.5 MMBoe for the year ended December 31, 2013. The decrease is primarily related to sales of all of our natural gas assets in the West Tavaputs Divestiture on December 10, 2013 and in the Piceance Divestiture on September 30, 2014. These decreases were partially offset by a 118% overall increase in DJ Basin production. Additional information concerning production is in the following table:

	Year Ended December 31, 2014				Year Ended December 31, 2013				% Increase (Decrease)			
	Oil	NGL	Natural Gas	Total	Oil	NGL	Natural Gas	Total	Oil	NGL	Natural Gas	Total
	(MBbls)	(MBbls)	(MMcf)	(MBoe)	(MBbls)	(MBbls)	(MMcf)	(MBoe)	(MBbls)	(MBbls)	(MMcf)	(MBoe)
Uinta Oil Program	1,821	119	2,220	2,310	1,996	142	3,024	2,642	(9)%	(16)%	(27)%	(13)%
DJ Basin	1,682	423	4,224	2,809	757	195	2,016	1,288	122%	117%	110%	118%
Piceance Basin	177	911	14,808	3,556	331	1,858	25,470	6,434	(47)%	(51)%	(42)%	(45)%
Powder River Oil	326	22	480	428	374	4	354	437	(13)%	450%	36%	(2)%
Other (1)	6	1	12	9	37	—	21,821	3,674	(84)%	*nm	(100)%	(100)%
Total	4,012	1,476	21,744	9,112	3,495	2,199	52,685	14,475	15%	(33)%	(59)%	(37)%

* Not meaningful.
(1) Other for 2013 includes Uinta - West Tavaputs natural gas volumes of 21,714 MMcf and oil production of 30 MBbls.

Hedging Activities. In 2014, approximately 87% of our oil volumes, 87% of our natural gas volumes and 18% of our NGL related volumes were subject to financial hedges, which resulted in an increase in oil revenues of $6.4 million, offset by decreases in natural gas revenues of $7.1 million and NGL revenues of $0.1 million after settlements for all commodity derivatives. Of the loss on total settlements of $0.8 million for the year ended December 31, 2014, a gain of $1.1 million was included in oil, gas and NGL production revenues and a loss of $1.9 million was included in commodity derivative gain (loss) in the Consolidated Statements of Operations.

In 2013, approximately 83% of our oil volumes, 92% of our natural gas volumes and 16% of our NGL related volumes were subject to financial hedges, which resulted in a decrease in oil revenues of $0.8 million, offset by increases in natural gas revenues of $10.8 million and NGL revenues of $2.8

million after settlements for all commodity derivatives. Of the gain on total settlements of $12.8 million for the year ended December 31, 2013, a gain of $7.5 million was included in oil, gas and NGL production revenues and a gain of $5.3 million was included in commodity derivative gain (loss) in the Consolidated Statements of Operations.

Other Operating Revenues. Other operating revenues increased to $8.2 million for the year ended December 31, 2014 from $2.5 million for the year ended December 31, 2013. Other operating revenues for 2014 consisted of $5.9 million related to the recovery of processing deductions on NGL revenues and $2.3 million of income from gathering and compression fees received from third parties. The $5.9 million related to the recovery of processing deductions on NGL revenues is based on guidance provided by the Office of Natural Resources Revenue (“ONRR”). Additional processing deductions were taken against NGL royalties paid on Federal and State leases from 2008 through July 2013 in the West Tavaputs area of the Uinta Basin and are now being recovered. The West Tavaputs properties were sold in December 2013.

Other operating revenues for 2013 consisted of $0.2 million in net gains realized from the sale of properties and $2.3 million of income from gathering, compression and salt water disposal fees received from third parties. The net realized gains from the sale of properties for the year ended December 31, 2013 related to a loss of $3.1 million from purchase price adjustments on the 2012 Divestiture, offset by a gain of $3.3 million from selldowns of other properties.

Lease Operating Expense. Lease operating expense (“LOE”) increased to $6.62 per Boe for the year ended December 31, 2014 from $4.85 per Boe for the year ended December 31, 2013. LOE on a per Boe basis is inherently higher from our oil producing properties such as those in our Uinta Oil and DJ Basin development areas. Due to the sale of natural gas properties with lower LOE per Boe in the West Tavaputs and Piceance Divestitures, we expect higher LOE on a per Boe basis in future periods.

Gathering, Transportation and Processing Expense. Gathering, transportation and processing (“GTP”) expense decreased to $3.89 per Boe for the year ended December 31, 2014 from $4.65 per Boe for the year ended December 31, 2013. GTP on a per Boe basis decreased due to inherently lower GTP from our oil producing properties such as those in our Uinta and DJ Basin development areas. Due to the sale of natural gas properties with higher GTP per Boe in the West Tavaputs and Piceance Divestitures, we expect lower GTP on a per Boe basis in future periods.

During March 2010, we entered into two firm natural gas pipeline transportation contracts to provide a guaranteed outlet for production from the West Tavaputs area of the Uinta Basin and the Gibson Gulch area of the Piceance Basin. These transportation contracts were not included in the sales of these assets in December 2013 and September 2014, respectively. Accordingly, we will continue to incur monthly demand charges of approximately $1.5 million for the remaining term of six years even though we no longer utilizes these contracts. These costs were included in unused commitments in the Consolidated Statements of Operations after completion of the Piceance Divestiture on September 30, 2014.

Production Tax Expense. Total production taxes increased to $31.3 million for the year ended December 31, 2014 from $27.2 million for the year ended December 31, 2013. Production taxes are primarily based on the wellhead values of production, which exclude gains and losses associated with hedging activities. Production taxes as a percentage of oil, natural gas and NGL sales before hedging adjustments were 6.8% and 4.9% for the years ended December 31, 2014 and December 31, 2013, respectively.

Production tax rates vary across the different areas in which we operate. As the proportion of our production changes from area to area, our average production tax rate will vary depending on the quantities produced from each area and the production tax rates in effect for those areas. The increase in the overall production tax rate is consistent with our production increase in areas with higher production tax rates. With the sale of all of our natural gas properties as of December 31, 2014, which were in areas with lower production tax rates, we expect higher production tax rates in future periods.

Exploration Expense. Exploration expense for the year ended December 31, 2014 was $0.5 million compared to $0.3 million for the year ended December 31, 2013. Exploration expense for the year ended December 31, 2014 consisted of $0.3 million of geological and geophysical seismic programs and $0.2 million for delay rentals across all basins. Exploration expense for the year ended December 31, 2013 consisted of $0.3 million for delay rentals across all basins.

Impairment, Dry Hole Costs and Abandonment Expense. Our impairment, dry hole costs and abandonment expense for the twelve months ended December 31, 2014 and 2013 is summarized below:

	Twelve Months Ended December 31,	
	2014	2013
	(in thousands)	
Non-cash impairment of proved oil and gas properties	$15,761	$206,953
Non-cash impairment of unproved oil and gas properties	24,082	19,598
Non-cash impairment of inventory	340	—
Dry hole costs	101	1,124
Abandonment expense	6,597	10,723
Total non-cash impairment, dry hole costs and abandonment expense	$46,881	$238,398

We review our proved oil and natural gas properties for impairment on a quarterly basis or whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. We estimate the expected future cash flows of our oil and gas properties and compare these undiscounted future cash flows to the carrying amount of the oil and gas properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we will adjust the carrying amount of the oil and natural gas properties to fair value. The factors used to determine fair value include, but are not limited to, recent sales prices of comparable properties, the present value of future cash flows, net of estimated operating and development costs using estimates of reserves, future commodity pricing, future production estimates, anticipated capital expenditures and various discount rates commensurate with the risk associated with realizing the projected cash flows.

Unproved oil and gas properties are assessed periodically for impairment on a property-by-property basis based on remaining lease terms, drilling results, reservoir performance, commodity price outlooks, future plans to develop acreage and other relevant matters. We generally expect impairments of unproved properties to be more likely to occur in periods of low commodity prices because we will be less likely to devote capital to exploration activities. If our attempts to market interests in certain properties to industry partners are unsuccessful, we may record additional leasehold impairments.

As the result of the Powder River Oil Divestiture, the carrying values of the remaining properties were analyzed relative to their estimated fair market values. As a result, the Company recognized impairment expense on proved properties of $14.8 million for the year ended December 31, 2014. These properties were classified as held for sale as of December 31, 2014. In addition, $1.0 million of proved property impairment expense was incurred during the year ended December 31, 2014 related to the West Tavaputs Divestiture based upon a true-up of previously estimated carrying value. See Note 4 of the Notes to Consolidated Financial Statements for more information related to these divestitures.

As a result of unsuccessful drilling and completion activity by an industry partner in the Paradox Basin, the Company recognized impairment expense of $11.6 million during the year ended December 31, 2014 related to the remaining unproved property in the Paradox Basin. The Company recognized impairment expense of $6.1 million related to certain unproved oil and gas properties in the Uinta Basin as a result of having no future plans to evaluate the acreage. In addition, the Company recognized impairment expense of $6.4 million as the result of the Powder River Oil Divestiture as discussed above.

We recognized $207.0 million of proved impairment expense and $2.5 million of unproved property impairment expense during the year ended December 31, 2013 related to our West Tavaputs properties based upon an analysis of the carrying value of the related properties relative to their estimated fair values. These assets were sold in December 2013. In addition, we recognized $17.1 million of impairment expense related to certain unproved oil and gas properties within exploration projects primarily as a result of having no future plans to evaluate the remaining acreage and an estimated market value below our carrying value.

Given the decline in current and future commodity prices, we will continue to review our acreage position and future drilling plans as well as assess the carrying value of our properties relative to their estimated fair values. Lower sustained commodity prices or additional commodity price declines may lead to additional property impairment in future periods.

Loss on Divestitures. Loss on divestitures for the year ended December 31, 2014 consisted of a $79.5 million loss related to the Piceance Divestiture and a $24.5 million loss related to the sale or exchange of the majority of our Powder River Basin assets ("Powder River Oil Divestiture") during the three months ended September 30, 2014, offset by $3.6 million in net gains realized from the sale of other properties. See Note 4 of the Notes to Consolidated Financial Statements for more information related to these divestitures.

Depreciation, Depletion and Amortization. DD&A decreased to $235.8 million for the year ended December 31, 2014 compared with $279.8 million for the year ended December 31, 2013. The decrease of $44.0 million was a result of a 37% decrease in production for the year ended December 31, 2014 compared with the year ended December 31, 2013, partially offset by an increase in the DD&A rate. The decrease in production accounted for a $103.7 million decrease in DD&A expense, while the overall increase in the DD&A rate accounted for $59.7 million of additional DD&A expense.

Under successful efforts accounting, depletion expense is calculated on a field-by-field basis based on geologic and reservoir delineation using the unit-of-production method. The capital expenditures for proved properties for each field compared to the proved reserves corresponding to each producing field determine a depletion rate for current production. For the year ended December 31, 2014, the relationship of capital expenditures, proved reserves and production from certain producing fields yielded a depletion rate of $25.88 per Boe compared with $19.33 per Boe for the year ended December 31, 2013. The increase in the DD&A rate during the year ended December 31, 2014 was due to an increase in oil development, which has higher capital cost per Boe compared to natural gas development. Future depletion rates will be adjusted to reflect capital expenditures, proved reserve changes and well performance.

Unused Commitments. Unused commitments for the year ended December 31, 2014 were $4.4 million. During March 2010, we entered into two firm natural gas pipeline transportation contracts to provide a guaranteed outlet for production from the West Tavaputs area of the Uinta Basin and the Gibson Gulch area of the Piceance Basin. These transportation contracts were not included in the sales of these assets in December 2013 and September 2014, respectively. Accordingly, we will continue to incur monthly demand charges of approximately $1.5 million for the remaining term of six years even though we no longer utilizes these contracts. These costs were previously included in gathering, transportation and processing expense in the Consolidated Statements of Operations prior to the completion of the Piceance Divestiture on September 30, 2014.

General and Administrative Expense. General and administrative expense, excluding non-cash stock-based compensation, decreased to $42.0 million for the year ended December 31, 2014 from $49.1 million for the year ended December 31, 2013. The decrease of $7.1 million was primarily the result of a 19% decrease in the number of employees as of December 31, 2014 compared to December 31, 2013, due to our divestitures. General and administrative expense, excluding non-cash stock-based compensation, is a non-GAAP measure. See Note 1 to the table on page 40 for a reconciliation and explanation. On a per Boe basis, general and administrative expense, excluding non-cash stock-based compensation, increased to $4.61 in 2014 from $3.39 in 2013, primarily related to the 37% decrease in production from 2014 compared with 2013.

Non-cash charges for stock-based compensation for the years ended December 31, 2014 and 2013 were $11.4 million and $15.8 million, respectively. Non-cash stock-based compensation expense for each of the years ended December 31, 2014 and 2013 related primarily to vesting of our stock option awards and nonvested shares of common stock issued to employees.

The components of non-cash stock-based compensation for the years ended December 31, 2014 and 2013 are shown in the following table:

	Year Ended December 31,	
	2014	2013
	(in thousands)	
Stock options and nonvested equity shares of common stock	$10,705	$14,758
Shares issued for 401(k) plan	600	724
Shares issued for directors' fees	75	351
Total	$11,380	$15,833

Interest Expense. Interest expense decreased to $69.6 million for the year ended December 31, 2014 from $88.5 million for the year ended December 31, 2013. The decrease for the year ended December 31, 2014 was primarily due to using the proceeds from the West Tavaputs Divestiture and Piceance Divestiture to lower the average debt balance. Our weighted average interest rate for the year ended December 31, 2014 was 6.9% compared with 7.2% for the year ended December 31, 2013.

Commodity Derivative Gain (Loss). Commodity derivative gain (loss) was a gain of $197.4 million for the year ended December 31, 2014 compared to a loss of $23.1 million for the year ended December 31, 2013. The gain or loss on commodity derivatives is related to fluctuations of oil, natural gas and NGL future pricing compared to actual pricing of commodity hedges in place as of December 31, 2014 and December 31, 2013.

The table below summarizes our commodity derivative gains and losses that were recognized in the periods presented:

	Year Ended December 31,	
	2014	2013
	(in thousands)	
Realized gain (loss) on derivatives not designated as cash flow hedges	$ (1,888)	$ 5,315
Unrealized gain (loss) on derivatives not designated as cash flow hedges	199,335	(28,383)
Total commodity derivative gain (loss)	$197,447	$(23,068)

Income Tax Benefit. Income tax expense totaled $17.9 million for the year ended December 31, 2014 compared with an income tax benefit of $118.6 million for the year ended December 31, 2013, resulting in effective tax rates of 54.3% and 38.1%, respectively. For both the 2014 and 2013 periods, our effective tax rate differs from the federal statutory rate primarily as a result of recording stock-based compensation expense and other operating expenses that are not deductible for income tax purposes as well as the effect of state income taxes. The effective tax rate change for December 31, 2014 was a result of recording an increase in the beginning deferred balances as a result of an increased state effective rate. At December 31, 2014, we had approximately $168.2 million of federal tax net operating loss carryforwards, or “NOLs”, which expire beginning in 2027. We also had a federal alternative minimum tax credit carryforward of $1.7 million, which has no expiration date. We believe it is more likely than not that we will use these tax attributes to offset and reduce tax liabilities in future years. At December 31, 2014, we had approximately $7.9 million of state income tax credit carryforwards. We continue to believe it is more likely than not that this deferred tax asset will not be realized, and therefore a valuation allowance is recorded for the state tax credits.

Year Ended December 31, 2013 Compared with Year Ended December 31, 2012

The following table sets forth selected operating data for the periods indicated:

	Year Ended December 31, 2013	Year Ended December 31, 2012	Increase (Decrease) Amount	Increase (Decrease) Percent
	($ in thousands, except per unit data)			
Operating Results:				
Operating and Other Revenues				
Oil, gas and NGL production	$565,555	$700,639	$(135,084)	(19)%
Other	2,538	(444)	2,982	*nm
Total operating and other revenues	$568,093	$700,195	$(132,102)	(19)%
Operating Expenses				
Lease operating expense	$ 70,217	$ 72,734	$ (2,517)	(3)%
Gathering, transportation and processing expense	67,269	106,548	(39,279)	(37)%
Production tax expense	27,172	25,513	1,659	7%
Exploration expense	337	8,814	(8,477)	(96)%
Impairment, dry hole costs and abandonment expense	238,398	67,869	170,529	*nm
Depreciation, depletion and amortization	279,775	326,842	(47,067)	(14)%
General and administrative expense (1)	49,069	52,222	(3,153)	(6)%
Non-cash stock-based compensation expense (1)	15,833	16,444	(611)	(4)%
Total operating expenses	$748,070	$676,986	$ 71,084	11%
Production Data (2):				
Oil (MBbls)	3,495	2,687	808	30%
Natural gas (MMcf)	52,685	101,486	(48,801)	(48)%
NGLs (MBbls)	2,199	—	2,199	*nm
Combined volumes (MBoe)	14,475	19,601	(5,126)	(26)%
Daily combined volumes (Boe/d)	39,658	53,701	(14,043)	(26)%
Average Realized Prices (2)(3):				
Oil (per Bbl)	$ 82.38	$ 84.96	$ (2.58)	(3)%
Natural gas (per Mcf) (4)	4.16	5.07	(0.91)	(18)%
NGLs (per Bbl)	28.31	—	28.31	*nm
Combined (per Boe)	39.35	37.90	1.45	4%
Average Costs (per Boe):				
Lease operating expense	$ 4.85	$ 3.71	$ 1.14	31%
Gathering, transportation and processing expense	4.65	5.44	(0.79)	(15)%
Production tax expense	1.88	1.30	0.58	45%
Depreciation, depletion and amortization (5)	19.33	17.49	1.84	11%
General and administrative expense (6)	3.39	2.66	0.73	27%

* Not meaningful.

(1) Non-cash stock-based compensation expense is presented herein as a separate line item but is combined with general and administrative expense for a total of $64.9 million and $68.7 million for the years ended December 31, 2013 and 2012, respectively, in the Consolidated Statements of Operations. This separate presentation is a non-GAAP measure. Management believes the separate presentation of the non-cash component of general and administrative expense is useful because the cash portion provides a better understanding of our required cash for general and administrative expenses. We also believe that this disclosure allows for a more accurate comparison to our peers, which may have higher or lower expenses associated with stock-based grants.

(2) Prior to 2013, NGL volumes were included within natural gas production data, which impacts the comparability for the two periods presented.
(3) Average realized prices shown in the table are net of the effects of all settled commodity hedging transactions related to current period production.
(4) Natural gas prices for 2012 include the effect of NGL related production and revenue.
(5) The DD&A per Boe as calculated based on the DD&A expense and production data presented in the table for the year ended December 31, 2012 is $16.67. However, the DD&A rate per Boe for the year ended December 31, 2012 of $17.49, as presented in the table above, excludes fourth quarter production of 911 MBoe, associated with our properties that were sold as of December 31, 2012.
(6) Excludes non-cash stock-based compensation expense as described in Note 1 above. This presentation is a non-GAAP measure. Average costs per Boe for general and administrative expense, including non-cash stock-based compensation expense, as presented in the Consolidated Statements of Operations, were $4.48 and $3.50 for the years ended December 31, 2013 and 2012, respectively.

Production Revenues and Volumes. Production revenues decreased to $565.6 million for the year ended December 31, 2013 from $700.6 million for the year ended December 31, 2012. The decrease in production revenues was primarily due to a 26% decrease in production volumes, offset by an increase in average prices. The decrease in production volumes reduced production revenues by approximately $200.2 million, while the increase in average prices increased production revenues by approximately $65.2 million.

We discontinued hedge accounting as of January 1, 2012. All accumulated gains or losses related to the discontinued cash flow hedges were recorded in accumulated other comprehensive income (“AOCI”) as of January 1, 2012 and will remain in AOCI until the underlying transaction occurs. As the underlying transaction occurs, these gains or losses are reclassified from AOCI into oil, gas and NGL production revenues. The amount reclassified to oil, gas and NGL production revenues was a gain of $7.5 million and $81.2 million for the years ended December 31, 2013 and 2012, respectively.

Total production volumes of 14.5 MMBoe for the year ended December 31, 2013 decreased from 19.6 MMBoe for the year ended December 31, 2012. We completed a sale of natural gas assets on December 31, 2012, including 100% of our Wind River Basin and Powder River Basin—Coalbed Methane properties (“PRB-CBM”) and an initial 18% interest in the Gibson Gulch assets in the Piceance Basin that progresses to a 26% interest in 2016 (the “2012 Divestiture”). Lower natural gas commodity prices caused us to discontinue drilling activity in the Piceance Basin and West Tavaputs area in the Uinta Basin in 2012 to concentrate on our oil development programs, which has continued to negatively impact 2013 gas production volumes. These decreases were partially offset by a 30% overall increase in oil production with increases in the Uinta Oil Program, DJ Basin and Powder River Oil Program. Additional information concerning production is in the following table:

	Year Ended December 31, 2013				Year Ended December 31, 2012				% Increase (Decrease)			
	Oil	NGL [1]	Natural Gas [1]	Total	Oil	NGL [1]	Natural Gas [1]	Total	Oil	NGL [1]	Natural Gas [1]	Total
	(MBbls)	(MBbls)	(MMcf)	(MBoe)	(MBbls)	(MBbls)	(MMcf)	(MBoe)	(MBbls)	(MBbls)	(MMcf)	(MBoe)
DJ Basin	757	195	2,016	1,288	397	—	1,264	608	91%	*nm	59%	112%
Uinta Oil Program	1,996	142	3,024	2,642	1,479	—	2,653	1,921	35%	*nm	14%	38%
Piceance Basin	331	1,858	25,470	6,434	619	—	48,072	8,631	(47)%	*nm	(47)%	(25)%
Powder River Oil	374	4	354	437	101	—	126	122	270%	*nm	181%	258%
Uinta- West Tavaputs	30	—	21,714	3,649	61	—	34,497	5,810	(51)%	*nm	(37)%	(37)%
Other [2]	7	—	107	25	30	—	14,874	2,509	(77)%	*nm	(99)%	(99)%
Total	3,495	2,199	52,685	14,475	2,687	—	101,486	19,601	30%	*nm	(48)%	(26)%

* Not meaningful.

(1) Prior to 2013, NGL volumes were included in natural gas production data, which impacts the comparability for the two periods presented.
(2) Other for 2012 includes PRB–CBM natural gas volumes of 10,888 MMcf, Wind River natural gas production volumes of 3,913 MMcf and oil production of 18 MBbls.

Hedging Activities. In 2013, approximately 83% of our oil volumes, 92% of our natural gas volumes and 16% of our NGL related volumes were subject to financial hedges, which resulted in a decrease in oil revenues of $0.8 million, partially offset by increases in natural gas revenues of $10.8 million and NGL production revenues of $2.8 million after settlements for all commodity derivatives. Of the gain on total settlements of $12.8 million for the year ended December 31, 2013, a gain of $7.5 million was included in oil, gas and NGL production revenues and a gain of $5.3 million was included in commodity derivative gain (loss) in the Consolidated Statements of Operations. In 2012, approximately 76% of our oil volumes, 68% of our natural gas volumes (excluding basis only swaps, which were equivalent to 7% of our natural gas volumes), and 23% of our NGL related recoveries were subject to financial hedges, which resulted in an increase in oil revenues of $15.0 million, of which $3.9 million was included in oil, gas and NGL production revenues, and an increase natural gas revenues of $108.5 million, of which $77.2 million was included in oil, gas and NGL production revenues, after settlements for all commodity derivatives, including basis only and NGL swaps.

Other Operating Revenues. Other operating revenues increased to $2.5 million for the year ended December 31, 2013 from a loss of $0.4 million for the year ended December 31, 2012. Other operating revenues for 2013 consisted of $0.2 million in net gains realized from the sale of properties and $2.3 million of income from gathering, compression and salt water disposal fees received from third parties. The net realized gains from the sale of properties for the year ended December 31, 2013 related to a loss of $3.1 million from purchase price adjustments on the 2012 Divestiture, offset by a gain of $3.3 million from selldowns of other properties. Other operating revenues for 2012 consisted of a $4.5 million loss on the sale of our natural gas assets including 100% of our Wind River Basin and Powder River Basin coalbed methane assets, and a non-operating working interest in our Piceance Basin development property. This loss was offset by $2.7 million of income from gathering, compression and salt-water disposal fees received from third parties and $1.4 million from the sale of seismic data.

Lease Operating Expense. Lease operating expense ("LOE") increased to $4.85 per Boe for the year ended December 31, 2013 from $3.71 per Boe for the year ended December 31, 2012. LOE on a per Boe basis is inherently higher from our oil producing properties such as those in our Uinta Oil and DJ Basin development areas. In addition, the 2012 Divestiture consisted of natural gas properties with lower LOE per Boe, which contributed to a higher comparative LOE per Boe unit cost in the year ended December 31, 2013.

Gathering, Transportation and Processing Expense. Gathering, transportation and processing ("GTP") expense decreased to $4.65 per Boe for the year ended December 31, 2013 from $5.44 per Boe for the year ended December 31, 2012. The decrease is primarily due to an increase in oil production for the year ended December 31, 2013, which has lower GTP expense than natural gas as well as the sale of our Powder River- CBM assets as part of the 2012 Divestiture, which had higher GTP expense per Boe compared to our other assets.

Production Tax Expense. Total production taxes increased to $27.2 million for the year ended December 31, 2013 from $25.5 million for the year ended December 31, 2012. Production taxes are primarily based on the wellhead values of production, which exclude gains and losses associated with hedging activities. Production taxes as a percentage of oil, natural gas and NGL sales before hedging adjustments were 4.9% and 4.1% for the years ended December 31, 2013 and December 31, 2012, respectively.

Production tax rates vary across the different areas in which we operate. As the proportion of our production changes from area to area, our average production tax rate will vary depending on the quantities produced from each area and the production tax rates in effect for those areas. The increase in the overall production tax rate is consistent with our production increase in areas with higher production tax rates.

Exploration Expense. Exploration expense for the year ended December 31, 2013 was $0.3 million compared to $8.8 million for the year ended December 31, 2012. Exploration expense for the year ended December 31, 2013 consisted of $0.3 million for delay rentals across all basins. Exploration expense for the year ended December 31, 2012 consisted of $7.9 million of geological and geophysical seismic programs and $0.9 million for delay rentals across all basins.

Impairment, Dry Hole Costs and Abandonment Expense. Our impairment, dry hole costs and abandonment expense increased to $238.4 million for the year ended December 31, 2013 from $67.9 million for the year ended December 31, 2012.

For the year ended December 31, 2013, impairment expense was $226.6 million, abandonment expense was $10.7 million and dry hole expense was $1.1 million. The $226.6 million of impairment expense for the year ended December 31, 2013 included $207.0 million related to proved oil and gas properties and $19.6 million related to unproved oil and gas properties. We recognized $207.0 million of proved impairment expense and $2.5 million of unproved property impairment expense during the year ended December 31, 2013 related to our West Tavaputs properties based upon an analysis of the carrying value of the related properties relative to their estimated fair values. These assets were sold in December 2013. In addition, we recognized $17.1 million of impairment expense related to certain unproved oil and gas properties within exploration projects primarily as a result of having no future plans to evaluate the remaining acreage and an estimated market value below our carrying value. The impairment expense contributed substantially to our net loss of $192.7 million for the year ended December 31, 2013.

For the year ended December 31, 2012, impairment expense was $37.3 million, abandonment expense associated with exploratory drilling locations was $9.6 million and dry hole costs were $21.0 million. The $37.3 million related to impairing certain unproved oil and gas properties within various exploration and development projects primarily as a result of unfavorable market conditions or having no future plans to evaluate the remaining acreage. For the year ended December 31, 2012, we did not record any impairment charges related to proved oil and gas properties.

We evaluate the impairment of our proved oil and gas properties on a property-by-property basis quarterly or whenever events or changes in circumstances indicate a property's carrying amount may not be recoverable. If the carrying amount exceeds the property's estimated fair value, we will adjust the carrying amount of the property to fair value through a charge to impairment expense.

Unproved oil and gas properties are also assessed periodically for impairment on a property-by-property basis based on remaining lease terms, drilling results, reservoir performance, commodity price outlooks or future plans to develop existing acreage. We continue to review our acreage position and future drilling plans based on the current price environment. If our attempts to market interests in certain properties to industry partners are unsuccessful, we may record additional leasehold impairments and abandonments in exploration prospects.

Dry hole costs of $1.1 million for the year ended December 31, 2013 primarily relate to additional costs on wells deemed to be dry holes in 2012. Dry hole costs of $21.0 million for the year ended December 31, 2012 primarily relate to two unsuccessful exploratory natural gas wells in the Paradox Basin and one unsuccessful exploratory well in the Alberta Basin.

Depreciation, Depletion and Amortization. DD&A decreased to $279.8 million for the year ended December 31, 2013 compared with $326.8 million for the year ended December 31, 2012. The decrease of $47.0 million was a result of a 26% decrease in production for the year ended December 31, 2013 compared with the year ended December 31, 2012, offset by an increase in the DD&A rate. The decrease in production accounted for a $89.6 million decrease in DD&A expense, while the overall increase in the DD&A rate accounted for $42.6 million of additional DD&A expense. The increase in the DD&A rate during the year ended December 31, 2013 was due to an increase in the mix of oil projects in 2013 as compared to 2012, as oil projects have higher capital costs per reserve unit compared to natural gas projects, and the sale of properties with lower DD&A rates in the 2012 Divestiture.

Under successful efforts accounting, depletion expense is calculated on a field-by-field basis based on geologic and reservoir delineation using the unit-of-production method. The capital expenditures for proved properties for each field compared to the proved reserves corresponding to each producing field to determine a depletion rate for current production. For the year ended December 31, 2013, the relationship of capital expenditures, proved reserves and production from certain producing fields yielded a depletion rate of $19.33 per Boe compared with $17.49 per Boe for the year ended December 31, 2012. Future depletion rates will be adjusted to reflect capital expenditures, proved reserve changes and well performance.

General and Administrative Expense. General and administrative expense, excluding non-cash stock-based compensation, decreased to $49.1 million for the year ended December 31, 2013 from $52.2 million for the year ended December 31, 2012. The decrease of $3.1 million was primarily the result of a 26% decrease in the number of employees as of December 31, 2013 compared to December 31, 2012, due to the Company's divestitures. General and administrative expense, excluding non-cash stock-based compensation, is a non-GAAP measure. See Note 1 to the table on page 46 for a reconciliation and explanation. On a per Boe basis, general and administrative expense, excluding non-cash stock-based compensation, increased to $3.39 in 2013 from $2.66 in 2012, primarily related to the 26% decrease in production from 2013 compared with 2012.

Non-cash charges for stock-based compensation for the years ended December 31, 2013 and 2012 were $15.8 million and $16.4 million, respectively. Non-cash stock-based compensation expense for each of the years ended December 31, 2013 and 2012 related primarily to vesting of our stock option awards and nonvested shares of common stock issued to employees.

The components of non-cash stock-based compensation for the years ended December 31, 2013 and 2012 are shown in the following table:

	Year Ended December 31,	
	2013	2012
	(in thousands)	
Stock options and nonvested equity shares of common stock	$14,758	$15,435
Shares issued for 401(k) plan	724	733
Shares issued for directors' fees	351	276
Total	$15,833	$16,444

Interest Expense. Interest expense decreased to $88.5 million for the year ended December 31, 2013 from $95.5 million for the year ended December 31, 2012. The decrease for the year ended December 31, 2013 was primarily due to a lower weighted average interest rate as a result of the redemption of our 9.875% Senior Notes on July 15, 2013. Our weighted average interest rate for the year ended December 31, 2013 was 7.2% compared with 8.2% for the year ended December 31, 2012.

Commodity Derivative Gain (Loss). Commodity derivative gain (loss) was a loss of $23.1 million for the year ended December 31, 2013 compared to a gain of $72.8 million for the year ended December 31, 2012. The decrease was primarily due to a decrease in our natural gas hedging contracts as a result of lower natural gas volumes hedged and a large increase in oil futures pricing for the year ended December 31, 2013 compared with December 31, 2012.

The table below summarizes the Company's commodity derivative gains and losses that were recognized in the periods presented:

	Year Ended December 31,	
	2013	2012
	(in thousands)	
Realized gain on derivatives not designated as cash flow hedges	$ 5,315	$42,305
Unrealized gain (loss) on derivatives not designated as cash flow hedges	(28,383)	30,454
Total commodity derivative gain (loss)	$(23,068)	$72,759

Income Tax Benefit. Income tax benefit totaled $118.6 million for the year ended December 31, 2013 compared with an income tax expense of $1.6 million for the year ended December 31, 2012, resulting in effective tax rates of 38.1% and 73.8%, respectively. For both the 2013 and 2012 periods, our effective tax rate differs from the federal statutory rate primarily as a result of recording stock-based compensation expense and other operating expenses that are not deductible for income tax purposes as well as the effect of state income taxes. The effective tax rate for December 31, 2012 was exceptionally high due to the amount of non-deductible expenses relative to the low operating income coupled with the effect a statutory rate increase had on the Company's prior year net deferred tax liability. At December 31, 2013, we had approximately $218.0 million of federal tax net operating loss carryforwards, or "NOLs", which expire through 2033. We also had a federal alternative minimum tax credit carryforward of $0.7 million, which has no expiration date. We believe it is more likely than not that we will use these tax attributes to offset and reduce tax liabilities in future years. At December 31, 2013, the Company had approximately $5.9 million of state income tax credit carryforwards. We continue to believe it is more likely than not that this deferred tax asset will not be realized, and therefore a valuation allowance is recorded for the state tax credits.

Capital Resources and Liquidity

Our primary sources of liquidity since our formation in January 2002 have been net cash provided by operating activities, sales and other issuances of equity and debt securities, notes and senior notes, bank credit facilities, proceeds from sale-leasebacks, joint exploration agreements and sales of interests in properties. Our primary use of capital has been for the development, exploration and acquisition of oil and natural gas properties. As we pursue profitable reserves and production growth, we continually monitor the capital resources, including potential issuances of equity and debt securities, available to us to meet our future financial obligations, planned capital expenditure activities and liquidity. Our future success in growing proved reserves and production will be highly dependent on capital resources available to us and our success in finding or acquiring additional reserves. We believe that we have significant liquidity available to us from cash flows from operations and under our Amended Credit Facility for our planned uses of capital. However, we expect to pursue opportunities to further improve our liquidity position through capital markets or other transactions if we believe conditions to be favorable.

At December 31, 2014, we had cash and cash equivalents of $165.9 million and no amounts outstanding under our Amended Credit Facility. Our borrowing base is dependent on our proved reserves and hedge position and as of December 31, 2014 was $375.0 million. Our borrowing capacity was reduced by $26.0 million to $349.0 million as of December 31, 2014 due to an outstanding irrevocable letter of credit related to a firm transportation agreement.

Cash Flow from Operating Activities

Net cash provided by operating activities was $261.7 million, $265.3 million and $388.4 million in 2014, 2013 and 2012, respectively. The changes in net cash provided by operating activities are discussed above in “Results of Operations”. The decrease in net cash provided by operating activities for the years ended December 31, 2014 and 2013 compared to 2012 was largely due to our asset sales and the related 37% and 26% decreases in production volumes in 2014 and 2013, respectively. In addition, operating costs decreased for the years ended December 31, 2014 and 2013, which partially offset the decrease in operating cash flows due to lower production volumes.

Commodity Hedging Activities

Our operating cash flow is sensitive to many variables, the most significant of which is the volatility of prices for oil, natural gas and NGLs. Prices for these commodities are determined primarily by prevailing market conditions. National and worldwide economic activity and political stability, weather, infrastructure capacity to reach markets, supply levels and other variable factors influence market conditions for these products. These factors are beyond our control and are difficult to predict.

To mitigate some of the potential negative impact on cash flow caused by changes in oil, natural gas and NGL prices, we have entered into financial commodity swap contracts to receive fixed prices for a portion of our production revenue. At December 31, 2014, we had in place crude oil swaps covering portions of our 2015, 2016 and 2017 production and natural gas swaps covering portions of our 2015 and 2016 production.

In addition to financial contracts, we may at times enter into various physical commodity contracts for the sale of oil, natural gas and NGLs that cover varying periods of time and have varying pricing provisions. These physical commodity contracts qualify for the normal purchase and normal sales exception and, therefore, are not subject to hedge or mark-to-market accounting. The financial impact of physical commodity contracts is included in oil, gas and NGL production revenues at the time of settlement.

All derivative instruments, other than those that meet the normal purchase and normal sales exception as mentioned above, are recorded at fair market value and are included in the Consolidated Balance Sheets as assets or liabilities. All fair values are adjusted for non-performance risk. All changes in the derivative’s fair value are recorded in earnings. These mark-to-market adjustments produce a degree of earnings volatility but have no cash flow impact relative to changes in market prices. Our cash flow is only impacted when the associated derivative instrument contract is settled by making a payment to or receiving a payment from the counterparty.

At December 31, 2014, the estimated fair value of all of our commodity derivative instruments was a net asset of $195.0 million, comprised of current and long-term assets.

The table below summarizes the realized and unrealized gains and losses that we recognized related to our oil, natural gas and NGL derivative instruments for the periods indicated:

	Year Ended December 31,		
	2014	2013	2012
		(in thousands)	
Commodity derivative settlements on derivatives designated as cash flow hedges [1]	$ 1,070	$ 7,463	$81,166
Realized gains (losses) on derivatives not designated as cash flow hedges [2][3]	$ (1,888)	$ 5,315	$42,305
Unrealized gains (losses) on derivatives not designated as cash flow hedges [2][3]	199,335	(28,383)	30,454
Total commodity derivative gain (loss)	$197,447	$(23,068)	$72,759

(1) Included in oil, gas and NGL production revenues in the Consolidated Statements of Operations.
(2) Included in commodity derivative gain (loss) in the Consolidated Statements of Operations.
(3) Realized and unrealized gains and losses on commodity derivatives are presented herein as separate line items but are combined for a total commodity derivative gain (loss) in the Consolidated Statements of Operations. This separate presentation is a non-GAAP measure. Management believes the separate presentation of the realized and unrealized commodity derivative gains and losses is useful because the realized cash settlement portion provides a better understanding of our hedge position. We also believe that this disclosure allows for a more accurate comparison to our peers.

The following table summarizes all of our hedges in place as of December 31, 2014:

Contract	Total Hedged Volumes	Quantity Type	Weighted Average Fixed Price	Index Price	Fair Market Value (in thousands)
Swap Contracts:					
2015					
Oil	4,022,600	Bbls	$90.59	WTI	$135,788
Natural gas	7,207,000	MMBtu	$ 4.13	NWPL	9,438
2016					
Oil	1,737,000	Bbls	$87.46	WTI	41,883
Natural gas	1,830,000	MMbtu	$ 4.10	NWPL	1,557
2017					
Oil	365,000	Bbls	$84.74	WTI	6,310
Total					$194,976

By removing the price volatility from a portion of our oil related revenue for 2015, 2016 and 2017, and natural gas related revenue for 2015 and 2016, we have mitigated, but not eliminated, the potential effects of changing prices on our operating cash flow for those periods. While mitigating negative effects of falling commodity prices, these derivative contracts also limit the benefits we would receive from increases in commodity prices.

It is our policy to enter into derivative contracts with counterparties that are lenders in the Amended Credit Facility, affiliates of lenders in the Amended Credit Facility or potential lenders in the Amended Credit Facility. Our derivative contracts are documented using an industry standard contract known as a Schedule to the Master Agreement and International Swaps and Derivative Association, Inc. ("ISDA") Master Agreement or other contracts. Typical terms for these contracts include credit support requirements, cross default provisions, termination events and set-off provisions. We are not required to provide any credit support to our counterparties other than cross collateralization with the properties securing the Amended Credit Facility. We have set-off provisions in our derivative contracts with lenders under our Amended Credit Facility which, in the event of a counterparty default, allow us to set-off amounts owed to the defaulting counterparty under the Amended Credit Facility or other obligations against monies owed us under derivative contracts. Where the counterparty is not a lender under the Amended Credit Facility, we may not be able to set-off amounts owed by us under the Amended Credit Facility, even if such counterparty is an affiliate of a lender under such facility.

Capital Expenditures

Our capital expenditures are summarized in the following tables for the periods indicated:

	Year Ended December 31,		
Basin/Area	**2014**	**2013**	**2012**
		(in millions)	
DJ	$384.0	$209.3	$226.2
Uinta Oil Program	152.9	204.4	314.5
Piceance	—	3.9	207.7
Powder River Oil	29.1	52.3	47.4
Uinta – West Tavaputs	—	—	106.5
Other	3.3	4.1	60.3
Total (1)(2)(3)	$569.3	$474.0	$962.6

	Year Ended December 31,		
	2014	**2013**	**2012**
		(in millions)	
Acquisitions of proved and unproved properties and other real estate	$ 15.1	$ 16.2	$168.5
Drilling, development, exploration and exploitation of oil and natural gas properties (4)	550.0	456.2	778.4
Geologic and geophysical costs	0.5	0.3	8.8
Furniture, fixtures and equipment	3.7	1.3	6.9
Total (1)(2)(3)	$569.3	$474.0	$962.6

(1) Capital expenditures for the year ended December 31, 2014 exclude $79.0 million related to property acquired through property exchanges.
(2) For the years ended December 31, 2014, 2013 and 2012, we received $555.4 million, $306.3 million and $325.3 million, respectively, of proceeds principally from the sale of interests in oil and gas properties, which are not deducted from the capital expenditures presented above.
(3) Excludes future reclamation liabilities of negative $8.6 million, negative $6.6 million and $7.5 million for the years ended December 31, 2014, 2013 and 2012, respectively, and includes exploration, dry hole and abandonment costs, which are expensed under successful efforts accounting, of $7.2 million, $12.2 million and $39.3 million for the years ended December 31, 2014, 2013 and 2012, respectively.
(4) Includes related gathering and facilities costs.

Capital expenditures for acquisitions of proved and unproved properties and other real estate were $15.1 million for the year ended December 31, 2014. This was primarily related to acquisitions of unproved properties in the DJ and Uinta Basins. The increase in drilling, development, exploration and exploitation of oil and natural gas properties to $550.0 million for the year ended December 31, 2014 from $456.2 million for the year ended December 31, 2013 primarily related to an increase in development drilling and completion activities within the DJ Basin.

Capital expenditures for acquisitions of proved and unproved properties and other real estate were $16.2 million for the year ended December 31, 2013. This was primarily related to our acquisitions of proved and unproved properties in the DJ, Powder River and Uinta Basins. The decrease in drilling, development, exploration and exploitation of oil and natural gas properties to $456.2 million from $778.4 million for the year ended December 31, 2012 related to a decrease in development drilling and completion activities in the Uinta and Piceance Basins.

Our current estimated capital expenditure budget in 2015 is $240.0 million to $280.0 million, with all drilling activities targeting oil. The budget includes facilities costs and excludes acquisitions. We may adjust capital expenditures throughout the year as business conditions and operating results warrant. The amount, timing and allocation of capital expenditures is generally discretionary and within our control. If oil, natural gas and NGL prices decline to levels below our acceptable levels or costs increase to levels above our acceptable levels, we could choose to defer a portion of our budgeted capital expenditures until later periods to achieve the desired balance between sources and uses of liquidity generally by prioritizing capital projects to first focus on those that we believe will have the highest expected financial returns and ability to generate near-term cash flow. We routinely monitor and adjust our capital expenditures, including acquisitions and divestitures, in response to changes in prices and other economic and market conditions, availability of financing, drilling and acquisition costs, industry conditions, the timing of regulatory approvals, the availability of rigs, success or lack of success in drilling activities, contractual obligations, internally generated cash flow and other factors both within and outside of our control.

We believe that we have sufficient available liquidity with available cash under the Amended Credit Facility and cash flow from operations to fund our 2015 budgeted capital expenditures. Future cash flows are subject to a number of variables, including our level of oil and natural gas production, commodity prices and operating costs. There can be no assurance that operations and other capital resources will provide sufficient amounts of cash flow to maintain planned levels of capital expenditures.

Financing Activities

Amended Credit Facility. Our Amended Credit Facility has a maturity date of October 31, 2016 and current commitments and borrowing base of $375.0 million. As of December 31, 2014, we had no amounts outstanding under the Amended Credit Facility. As credit support for future payment under a contractual obligation, a $26.0 million letter of credit has been issued under the Amended Credit Facility, which reduces the current available borrowing capacity of the Amended Credit Facility to $349.0 million.

Interest rates are LIBOR plus applicable margins of 1.5% to 2.5% or ABR plus 0.5% to 1.5% and the commitment fee is between 0.375% to 0.5% based on borrowing base utilization. The average annual interest rates incurred on the Amended Credit Facility were 1.9% and 2.0% for the years ended December 31, 2014 and 2013, respectively.

The borrowing base is required to be re-determined twice per year, on or about April 1 and October 1. On September 30, 2014, the borrowing base was reduced to $375.0 million based on our June 30, 2014 proved reserves, as adjusted for the Piceance and Powder River Oil Divestitures and our hedge position. Future semi-annual borrowing bases will be computed based on proved oil, natural gas and NGL reserves, hedge positions and estimated future cash flows from those reserves, as well as any other outstanding debt of the Company.

The Amended Credit Facility is secured by oil and natural gas properties representing at least 80% of the value of our proved reserves and the pledge of all of the stock of our subsidiaries. The Amended Credit Facility contains certain financial covenants. We are currently in compliance with all financial covenants and have complied with all financial covenants since issuance.

5% Convertible Senior Notes Due 2028. On March 12, 2008, we issued $172.5 million aggregate principal amount of Convertible Notes. On March 20, 2012, $147.2 million of the outstanding principal amount, or approximately 85% of the outstanding Convertible Notes, were put to us and redeemed by us at par. We settled the notes in cash. After the redemption, $25.3 million aggregate principal amount of the Convertible Notes was outstanding. The Convertible Notes mature on March 15, 2028, unless earlier converted, redeemed or purchased by us. The Convertible Notes are senior unsecured obligations and rank equal in right of payment to all of the Company's existing and future senior unsecured indebtedness, are senior in right of payment to all of our future subordinated indebtedness, and are effectively subordinated to all of our secured indebtedness with respect to the collateral securing such indebtedness. The Convertible Notes are structurally subordinated to all present and future secured and unsecured debt and other obligations of our subsidiaries. The Convertible Notes are fully and unconditionally guaranteed by the subsidiaries that guarantee our indebtedness under the Amended Credit Facility, the 7.625% Senior Notes and the 7.0% Senior Notes.

The Convertible Notes bear interest at a rate of 5% per annum, payable semi-annually in arrears on March 15 and September 15 of each year. Holders of the remaining Convertible Notes may require us to purchase all or a portion of their Convertible Notes for cash on each of March 20, 2015, March 20, 2018 and March 20, 2023 at a purchase price equal to 100% of the principal amount of the Convertible Notes to be repurchased, plus accrued and unpaid interest, if any, up to but excluding the applicable purchase date. We have the right, with at least 30 days' notice, to call the Convertible Notes. The Company classified the Convertible Notes as a current obligation on the Consolidated Balance Sheets as of December 31, 2014 as the holders may require us to purchase their Convertible Notes for cash on March 20, 2015.

7.625% Senior Notes Due 2019. On September 27, 2011, we issued $400.0 million in principal amount of 7.625% Senior Notes due 2019 at par. The 7.625% Senior Notes mature on October 1, 2019. Interest is payable in arrears semi-annually on April 1 and October 1 of each year. The 7.625% Senior Notes are senior unsecured obligations and rank equal in right of payment with all of our other existing and future senior unsecured indebtedness, including the Convertible Notes and 7.0% Senior Notes. The 7.625% Senior Notes are redeemable on October 1, 2015 at our option at a redemption price of 103.813% of the principal amount of the notes. The 7.625% Senior Notes are fully and unconditionally guaranteed by our subsidiaries that guarantee our indebtedness under the Amended Credit Facility, the Convertible Notes and the 7.0% Senior Notes. The 7.625% Senior Notes include certain covenants that limit our ability to incur additional indebtedness, make restricted payments, create liens or sell assets and that prohibit us from paying dividends. We are currently in compliance with all financial covenants and have complied with all financial covenants since issuance.

7.0% Senior Notes Due 2022. On March 12, 2012, we issued $400.0 million in aggregate principal amount of 7.0% Senior Notes due 2022 at par. The 7.0% Senior Notes mature on October 15, 2022. Interest is payable in arrears semi-annually on April 15 and October 15 of each year. The 7.0% Senior Notes are senior unsecured obligations and rank equal in right of payment with all of our other existing and future senior unsecured indebtedness, including the Convertible Notes and 7.625% Senior Notes. The 7.0% Senior Notes are redeemable at our option on October 15, 2017 at a redemption price of 103.5% of the principal amount of the notes. The 7.0% Senior Notes are fully and unconditionally guaranteed by our subsidiaries that guarantee the Amended Credit Facility, the Convertible Notes and the 7.625% Senior Notes. The 7.0% Senior Notes include certain covenants that limit our ability to incur additional indebtedness, make restricted payments, create liens or sell assets and that prohibit us from paying dividends. We are currently in compliance with all financial covenants and have complied with all financial covenants since issuance.

Lease Financing Obligation Due 2020. On July 23, 2012, we entered into a lease financing arrangement with Bank of America Leasing & Capital, LLC as the lead bank (the "Lease Financing Obligation") whereby we received $100.8 million through the sale and subsequent leaseback of existing compressors and related facilities owned by us. The Lease Financing Obligation expires on August 10, 2020, and we have the option to purchase the equipment at the end of the lease term for the then current fair market value. The Lease Financing Obligation also contains an early buyout option where we may purchase the equipment on February 10, 2019. The lease payments related to the equipment are recognized as principal and interest expense based on a weighted average implicit interest rate of 3.3%. As the result of the disposition of equipment in the West Tavaputs Divestiture and the Piceance Divestiture, our remaining Lease Financing Obligation has been reduced to $3.6 million as of December 31, 2014 and the early buyout option is reduced to $1.8 million.

Our outstanding debt is summarized below:

		As of December 31, 2014			As of December 31, 2013		
	Maturity Date	Principal	Unamortized Discount	Carrying Amount	Principal	Unamortized Discount	Carrying Amount
			(in thousands)				
Amended Credit Facility (1)	October 31, 2016	$ —	$—	$ —	$115,000	$—	$115,000
Convertible Notes (3)	March 15, 2028 (3)	25,344	—	25,344	25,344	—	25,344
7.625% Senior Notes (4)	October 1, 2019	400,000	—	400,000	400,000	—	400,000
7.0% Senior Notes (5)	October 15, 2022	400,000	—	400,000	400,000	—	400,000
Lease Financing Obligation (6)	August 10, 2020	3,648	—	3,648	43,329	—	43,329
Total Debt		$828,992	$—	$828,992	$983,673	$—	$983,673
Less: Current Portion of Long-Term Debt (7)		25,770	—	25,770	4,591	—	4,591
Total Long-Term Debt		$803,222	$—	$803,222	$979,082	$—	$979,082

(1) The recorded value of the Amended Credit Facility approximates its fair value due to its floating rate structure.
(2) The aggregate estimated fair value of the Convertible Notes was approximately $25.1 million as of December 31, 2014 and 2013, based on reported market trades of these instruments.
(3) We have the right at any time with at least 30 days' notice to call the Convertible Notes, and the holders have the right to require us to purchase the notes on each of March 20, 2015, March 20, 2018 and March 20, 2023.
(4) The aggregate estimated fair value of the 7.625% Senior Notes was approximately $359.8 million and $430.2 million as of December 31, 2014 and 2013, respectively, based on reported market trades of these instruments.
(5) The aggregate estimated fair value of the 7.0% Senior Notes was approximately $366.0 million and $417.0 million as of December 31, 2014 and 2013, respectively, based on reported market trades of these instruments.
(6) The aggregate estimated fair value of the Lease Financing Obligation was approximately $3.5 million and $41.7 million as of December 31, 2014 and 2013, respectively. The decrease in estimated fair value is primarily related to the sale of equipment in the West Tavaputs and

Piceance Divestitures. Because there is no active, public market for the Lease Financing Obligation, the aggregate estimated fair value was based on market-based parameters of comparable term secured financing instruments.

(7) The current portion of long-term debt as of December 31, 2014 includes the current portion of the Lease Financing Obligation and the principal amount of the Convertible Notes. The Company classified the Convertible Notes as a current obligation as the holders may require us to purchase their Convertible Notes for cash on March 20, 2015.

(8) The current portion of long-term debt as of December 31, 2013 includes the current portion of the Lease Financing Obligation.

Credit Ratings. Our credit risk is evaluated by two independent rating agencies based on publicly available information and information obtained during our ongoing discussions with the rating agencies. Moody's Investor Services and Standard & Poor's Rating Services currently rate our 7.625% Senior Notes and 7.0% Senior Notes and have assigned a credit rating. We do not have any provisions that are linked to our credit ratings, nor do we have any credit rating triggers that would accelerate the maturity of amounts due under our Amended Credit Facility, the Convertible Notes, the 7.625% Senior Notes or the 7.0% Senior Notes. However, our ability to raise funds and the costs of any financing activities will be affected by our credit rating at the time any such financing activities are conducted.

Contractual Obligations. A summary of our contractual obligations as of and subsequent to December 31, 2014 is provided in the following table:

	Payments Due By Year						
	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter	Total
	(in thousands)						
Notes payable (1)	$ 553	$ 553	$ 553	$ 183	$ —	$ —	$ 1,842
7.625% Senior Notes (2)	30,500	30,500	30,500	30,500	422,875	—	544,875
7.0% Senior Notes (3)	28,000	28,000	28,000	28,000	28,000	478,167	618,167
Convertible Notes (4)	25,622	—	—	—	—	—	25,622
Lease Financing Obligation (5)	537	537	537	537	1,826	—	3,974
Purchase commitments (6)(7)	1,695	—	—	—	—	—	1,695
Office and office equipment leases and other (8)(9)	4,204	2,838	2,690	2,525	634	—	12,891
Firm transportation and processing agreements (7)(10)	17,742	18,692	18,692	18,692	18,692	29,595	122,105
Asset retirement obligations (11)	1,114	595	499	459	435	19,750	22,852
Total	$109,967	$81,715	$81,471	$80,896	$472,462	$527,512	$1,354,023

(1) Included in notes payable is a $26.0 million letter of credit that accrues interest at 2.0% and 0.125% per annum for participation fees and fronting fees, respectively. The expected term for the letter of credit is April 30, 2018. There is currently no balance outstanding under our Amended Credit Facility due October 31, 2016.

(2) On September 27, 2011, we issued $400.0 million aggregate principal amount of 7.625% Senior Notes. We are obligated to make annual interest payments through maturity in 2019 equal to $30.5 million.

(3) On March 25, 2012, we issued $400.0 million aggregate principal amount of 7.0% Senior Notes. We are obligated to make annual interest payments through maturity in 2022 equal to $28.0 million.

(4) On March 12, 2008, we issued $172.5 million aggregate principal amount of Convertible Notes. On March 20, 2012 approximately 85% of the outstanding Convertible Notes, representing $147.2 million of the then outstanding principal amount, were put to us. We settled the notes in cash and

recognized a gain on extinguishment of $1.6 million after completing a fair value analysis of the consideration transferred to holders of the Convertible Notes. After the redemption in March 2012, $25.3 million principal amount of the Convertible Notes is currently outstanding. We are obligated to make semi-annual interest payments on the Convertible Notes until either we call the remaining Convertible Notes or the holders put the Convertible Notes to us. The Company classified the Convertible Notes as a current obligation on the Consolidated Balance Sheets as of December 31, 2014 as the holders may require us to purchase their Convertible Notes for cash on March 20, 2015.

(5) The Lease Financing Obligation is calculated based on the aggregate undiscounted minimum future lease payments, which include both an interest and principal component.

(6) We have one take-or-pay carbon dioxide purchase agreement that expires in December 2015. The agreement imposes a minimum volume commitment ("MVC") to purchase CO_2 at a contracted price. The contract provides CO_2 used in fracture stimulation operations. If we do not take delivery of the minimum volume required, we are obligated to pay for the deficiency. As of December 31, 2014, $1.7 million of the future commitment is due by December 31, 2015.

(7) The values in the table represent the gross amounts that we are financially committed to pay. However, we will record in our financial statements our proportionate share based on our working interest and net revenue interest, which will vary from property to property.

(8) The lease for our principal offices in Denver extends through March 2019.

(9) Includes a sales throughput contract in the South Altamont area of the Uinta Oil Basin. Under this contract, we are obligated to sell and deliver a MVC of 450.0 MMcf for the period of December 1, 2014 to November 30, 2015. If the minimum volume is not delivered, we must make a deficiency payment of up to $0.8 million. As of December 31, 2014, we have satisfied approximately 19.3 MMcf of this commitment, resulting in an estimated deficiency payment of up to $0.7 million due December 1, 2015.

(10) We have entered into contracts that provide firm transportation capacity on pipeline systems. The remaining term on these contracts is six years. The contracts require us to pay transportation demand charges regardless of the amount of gas we deliver to the pipeline.

(11) Neither the ultimate settlement amounts nor the timing of our asset retirement obligations can be precisely determined in advance. See "Critical Accounting Policies and Estimates" below for a more detailed discussion of the nature of the accounting estimates involved in estimating asset retirement obligations.

Trends and Uncertainties

Regulatory Trends

Our future Rockies operations and cost of doing business may be affected by changes in regulations and the ability to obtain drilling permits. The regulatory environment continues to become more restrictive, which limits our ability to, and increases the costs of conducting our operations. Areas in which we operate are subject to federal, state, local and tribal regulations. Additional and more restrictive regulations have been seen at each of these governmental levels recently and there are initiatives underway to implement additional regulations and prohibitions on oil and gas activities. New rules may further impact our ability to obtain drilling permits and other required approvals in a timely manner and/or increase the costs of such permits or approvals. This may create substantial uncertainty about our production and capital expenditure targets.

Federal. Federal leases make up approximately 25% of our leaseholds. At the federal level, the policies of the current administration and the Department of the Interior have resulted in a more restrictive regulatory environment for oil and gas activities on public lands. The Secretary of Interior has issued policy directives that require additional analysis prior to leasing federal lands. These policies are directed at reducing controversy and improving predictability of the leasing process. We believe that until these policies are implemented and the requisite analyses are completed, the rate of federal leasing will decrease. The Bureau of Land Management ("BLM") and the U.S. Forest Service also have withdrawn parcels from planned lease sales in areas near our operations. A lawsuit seeks review of federal resource management plans prepared by the BLM for areas of Utah, including areas in which we operate. If this challenge is successful, it could impact our ability to operate and to obtain additional leases in the area. Additional litigation seeking to halt our and other companies' exploration and development activities throughout the Rockies can be expected. Proposals to cause expiration of undeveloped leases, to further limit funding for processing of federal drilling permits and to eliminate categorical exclusions for oil and gas activities have been reintroduced.

State. We also are experiencing increased attempts to more strictly regulate oil and gas activities at the state level. For example, several statewide ballot initiatives were proposed in early 2014 that would have restricted or limited oil and natural gas development in Colorado, notably by amending the Colorado constitution (i) to impose a 2,000 foot statewide drilling setback from occupied structures and (ii) to establish an environmental bill of rights increasing local government authority to enact environmental regulations that are more restrictive than those adopted by the state government. Proponents of these initiatives withdrew them in August 2014 under a political compromise reached with Colorado Governor John Hickenlooper. Under the compromise, the Governor appointed a 21 member oil and gas task force (the "Task Force") by Executive Order, directing it to examine a range of issues and policy options to respond to the public concerns inherent in the withdrawn ballot initiatives. The Task Force is to make its report to the Governor and the Colorado General Assembly by March 2015. The outcome of this Task Force process is unclear, especially considering the potential impact of the 2014 gubernatorial and legislative elections. It is possible, however, that recommendations could be made, and subsequently adopted by legislation or regulation, that might impede our planned drilling activities in Colorado, including increasing regulatory and operational costs.

In addition, new rules and policies have been imposed by the COGCC requiring disclosure of chemicals used in hydraulic fracturing, ground water monitoring, setbacks from occupied structures and existing wells, and most recently amendments to COGCC's enforcement policies, including increases in mandatory monetary penalties for certain violations. As discussed in "Items 1 and 2. Business and Properties—Operations—Environmental Matters and Regulation", Colorado regulators also promulgated new, statewide air emissions regulations in 2014 that are more stringent than federal requirements. Colorado continues to look at air emissions from the oil and natural gas sector and additional regulations in this respect are possible. Other states, and the EPA, have considered Colorado's air quality rules, including the most recent rules governing methane emissions, as potential models for additional regulation of the oil and natural gas sector. Several states also have proposed severance tax increases. These new state rules and policies could impose additional costs on our operations, delay permitting, and potentially impact profitability.

Local. Counties and municipalities regulate oil and gas activities primarily through local land use rules. Most counties and municipalities where we operate require special use permits for activities that previously were regulated by the states, adding new requirements and delays over previous operations. We expect additional attempts to regulate activities related to oil and gas operations by local governments, including potential moratoria or bans on hydraulic fracturing. For example, in Colorado, several municipalities have approved bans of varying length on hydraulic fracturing within their respective jurisdictions. Litigation is pending on the legality of these Colorado bans, but local governments in other states have enacted or considered enacting similar bans.

Tribal. We have experienced delays in obtaining permits to drill wells and access and rights of way agreements on tribal property, including our Lake Canyon and Black Tail Ridge projects. The failure to obtain permits has led us to declare a force majeure event in order to protect our rights under our Black Tail Ridge exploration and development agreement. Because of the current staffing of the permitting authorities, we believe that delays in obtaining permits will continue for the foreseeable future, which will delay our ability to drill wells in these areas.

Hydraulic Fracturing. The well completion technique known as hydraulic fracturing to stimulate production of natural gas and oil has come under increased scrutiny by the environmental community, and local, state, and federal jurisdictions. Hydraulic fracturing involves the injection of water, sand and additives under pressure, usually down casing that is cemented in the wellbore, into prospective rock formations at depth to stimulate oil and natural gas production. We use this completion technique on substantially all our wells. A more comprehensive discussion of potential risks and trends related to hydraulic fracturing is contained above in Item 1A Risk Factors. Although it is not possible at this time to predict the final outcome of any proposed legislation, or potential regulatory or policy developments regarding hydraulic fracturing, any new restrictions on hydraulic fracturing that may be imposed in areas in which we conduct business could result in increased compliance costs or additional operating restrictions and could lead to our inability to access, develop, and record natural gas and oil reserves in the future.

Air Quality Regulation. The regulation of air emissions from the oil and natural gas sector continues to be a significant focus for policy makers, regulators at all levels-federal, tribal, state, and local-as well as environmental groups. A more comprehensive discussion of government regulation and potential risks related to air emissions from our operations is included above in "Items 1 and 2. Business and Properties—Operations—Environmental Matters and Regulation". New or more stringent policies, rules, or regulations governing air emissions from the oil and natural gas sector could result in our inability to obtain permits necessary to construct and operate new facilities or operate existing facilities. In addition, even if we are able to obtain necessary permits, such new requirements could substantially increase our operating expenses and reduce our profits or make certain operations uneconomic.

Potential Impacts of Regulatory Trends. The increase in regulatory burdens and potential for continued lawsuits seeking to block activities as described above is likely to cause delays to our planned activities and could prevent some of these activities. This is expected to increase our costs and could result in lower production and reserves as our properties naturally decline without replacement production and reserves from new wells in addition to a reduction in the value of our current leases.

For additional detail, see "Items 1 and 2. Business and Properties—Operations—Environmental Matters and Regulation" and "Items 1 and 2. Business and Properties—Business—Operations—Other Regulation of the Oil and Gas Industry".

Declining Commodity Prices. The severe decline in oil prices that occurred late in 2014, which has continued into 2015, has increased the volatility and amplitude of the other risks facing us as described in this report and has impacted our unit price and may have an impact on our business and financial condition. If oil prices remain low for an extended period of time, drilling in our DJ and Uinta Oil projects may become uneconomic, which could affect future drilling plans and growth rates. Low commodity prices impact our revenue, which we partially mitigate with our hedging program. We currently have hedged approximately 90% of our expected 2015 production and 40% of our expected 2016 production at price levels that provide some economic certainty to our capital investments. Continued low commodity prices make it more challenging to hedge production at higher price levels. Lower sustained commodity prices or additional commodity price declines may lead to property impairment in future periods.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of these financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and related disclosure of contingent assets and liabilities. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of our consolidated financial statements. We provide expanded discussion of our more significant accounting policies, estimates and judgments below. We believe these accounting policies reflect our more significant estimates and assumptions used in preparation of our consolidated financial statements. See Note 2 of the Notes to the Consolidated Financial Statements for a discussion of additional accounting policies and estimates made by management.

Oil and Gas Properties

Our oil, natural gas and NGL exploration, development and production activities are accounted for using the successful efforts method. Under this method, all property acquisition costs and costs of exploratory and development wells are capitalized when incurred, pending determination of whether the property has proved reserves. If an exploratory well does not find proved reserves, the costs of drilling the well are charged to expense and remain within cash flows from investing activities in the Consolidated Statements of Cash Flows. The costs of development wells are capitalized whether productive or nonproductive. All exploratory wells are evaluated for economic viability within one year of well completion, and the related capitalized costs are reviewed quarterly. Exploratory wells that discover potentially economic reserves in areas where a major capital expenditure would be required before production could begin and where the economic viability of that major capital expenditure depends upon the successful completion of further exploratory work in the area remain capitalized if the well finds a sufficient quantity of reserves to justify its completion as a producing well, and we are making sufficient progress assessing the reserves and the economic and operating viability of the project. Oil and gas lease acquisition costs are also capitalized. Interest cost is capitalized as a component of property cost for significant exploration and development projects that require greater than six months to be readied for their intended use.

The application of the successful efforts method of accounting requires managerial judgment to determine the proper classification of wells designated as developmental or exploratory, which will ultimately determine the proper accounting treatment of the costs incurred. In addition to development on exploratory wells, we may drill scientific wells that are only used for data gathering purposes. The costs associated with these scientific wells are expensed as incurred as exploration expense. The results from a drilling operation can take considerable time to analyze, and the determination that commercial reserves have been discovered requires both judgment and industry experience.

Other exploration costs, including certain geological and geophysical expenses and delay rentals for gas and oil leases, are charged to expense as incurred. The sale of a partial interest in a proved property is accounted for as a cost recovery and no gain or loss is recognized as long as this treatment does not significantly affect the unit-of-production depletion rate. A gain or loss is recognized for all other sales of proved properties and is classified in other operating revenues. Maintenance and repairs are charged to expense, and renewals and betterments are capitalized to the appropriate property and equipment accounts.

Unproved oil and gas property costs are transferred to proved oil and gas properties if the properties are subsequently determined to be productive. Proceeds from sales of partial interests in unproved leases are accounted for as a recovery of cost without recognizing any gain until all costs are recovered. Unproved oil and gas properties are assessed periodically for impairment on a property-by-property basis based on remaining lease terms, drilling results, reservoir performance, commodity price outlooks, future plans to develop acreage and other relevant matters. We generally expect impairments of unproved properties to be more likely to occur in periods of low commodity prices because we will be less likely to devote capital to exploration activities. We continue to review our acreage position and future drilling plans based on the current price environment. If our attempts to market interests in certain properties to industry partners are unsuccessful, we may record additional leasehold impairments.

We review our proved oil and natural gas properties for impairment on an annual basis or whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. We estimate the expected future cash flows of our oil and gas properties and compare these undiscounted future cash flows to the carrying amount of the oil and gas properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we will adjust the carrying amount of the oil and natural gas properties to fair value. The factors used to determine fair value include, but are not limited to, recent sales prices of comparable properties, the present value of future cash flows, net of estimated operating and development costs using estimates of reserves, future commodity pricing, future production estimates, anticipated capital expenditures and various discount rates commensurate with the risk associated with realizing the projected cash flows.

Given the decline in current and estimated future commodity prices, we will continue to review our acreage position and future drilling plans as well as assess the carrying value of our properties relative to their estimated fair values. Lower sustained commodity prices or additional commodity price declines may lead to impairment in future periods.

The successful efforts method of accounting can have a significant impact on the operational results reported when we are entering a new exploratory area in anticipation of finding a gas and oil field that will be the focus of future development drilling activity. If initial exploratory wells are unsuccessful, they are expensed. Seismic costs can be substantial, which will result in additional exploration expenses when incurred.

Our investment in oil and natural gas properties includes an estimate of the future costs associated with dismantlement, abandonment and restoration of our properties. The present value of the estimated future costs to dismantle, abandon and restore a well location are added to the capitalized costs of our oil and gas properties and recorded as a long-term liability. The capitalized cost is included in the oil and natural gas property costs that are depleted over the life of the assets.

The recognition of an asset retirement obligation ("ARO") requires that management make numerous estimates, assumptions and judgments regarding such factors as amounts, future advances in technology, timing of settlements, the credit-adjusted risk-free rate to be used and inflation rates. In periods subsequent to initial measurement of the ARO, we must recognize period-to-period changes in the liability resulting from the passage of time, revisions to either the amount of the original estimate of undiscounted cash flows or changes in inflation factors and changes to our credit-adjusted risk-free rate as market conditions warrant. Any such changes that result in upward or downward revisions in the estimated obligation will result in an adjustment to the related capitalized asset and corresponding liability on a prospective basis and an adjustment in our DD&A expense in future periods.

The provision for depletion of oil and gas properties is calculated on a field-by-field basis using the unit-of-production method. Natural gas is converted to barrel of oil equivalents, Boe, at the standard rate of six Mcf to one barrel. Our rate of recording DD&A is dependent upon our estimates of total proved and proved developed reserves, which incorporate assumptions regarding future development and abandonment costs as well as our level of capital spending. If the estimates of total proved or proved developed reserves decline, the rate at which we record DD&A expense increases, reducing our net income. This decline may result from lower market prices, which may make it uneconomic to drill for and produce higher cost fields. We are unable to predict changes in reserve quantity estimates as such quantities are dependent on the success of our exploitation and development program, as well as future economic conditions.

Oil and Gas Reserve Quantities

Our estimate of proved reserves is based on the quantities of oil and natural gas that geological and engineering data demonstrate with reasonable certainty to be commercially recoverable in future years from known reservoirs under existing economic and operating conditions. Our proved reserves estimates are audited on a well-by-well basis by an independent third party engineering firm. In the aggregate, the independent third party petroleum engineer estimates of total net proved reserves are within 10% of our internal estimates as of December 31, 2014.

Reserves and their relation to estimated future net cash flows impact our depletion and impairment calculations. As a result, adjustments to depletion and impairment are made concurrently with changes to reserves estimates. We prepare our reserves estimates, and the projected cash flows derived from these reserves estimates, in accordance with SEC guidelines. Our independent third party engineering firm adheres to the same guidelines when auditing our reserve reports. The accuracy of our reserves estimates is a function of many factors including the following: the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions and the judgments of the individuals preparing the reserves estimates.

The process of estimating oil and natural gas reserves is very complex, requiring significant decisions in the evaluation of all available geological, geophysical, engineering and economic data. The data for a given field may also change substantially over time as a result of numerous factors, including additional development activity, evolving production history and continued reassessment of the viability of production under varying economic conditions. As a result, material revisions to existing reserves estimates may occur from time to time. Although every reasonable effort is made to ensure that the reported reserves estimates represent the most accurate assessments possible, the subjective decisions and variances in available data for various fields make these estimates generally less precise than other estimates included in our financial statements. As such, reserves estimates may materially vary from the ultimate quantities of oil and natural gas eventually recovered.

Please refer to the reserve disclosures in “Items 1 and 2—Business and Properties” for further detail on reserves data.

Revenue Recognition

We record revenues from the sales of oil, natural gas and NGLs in the month that delivery to the purchaser has occurred and title has transferred. We receive payment from one to three months after delivery. At the end of each month, we estimate the amount of production delivered to purchasers and the price we will receive. Variances between our estimated revenue and actual payment are recorded in the month the payment is received. Historically, any differences have been insignificant.

Derivative Instruments and Hedging Activities

We use derivative financial instruments to achieve a more predictable cash flow from our oil, natural gas and NGLs production by reducing our exposure to price fluctuations. These derivative instruments are recorded at fair market value and included in the balance sheet as assets or liabilities.

Effective January 1, 2012, we elected to discontinue hedge accounting prospectively. Consequently, as of January 1, 2012, we no longer designate any hedges as cash flow hedges and we elected to de-designate all commodity hedge instruments that were previously designated as cash flow hedges as of December 31, 2011. The election to de-designate commodity hedges did not impact our reported cash flows, did not affect the economic substance of these transactions and changed only how these transactions were reported in the Consolidated Financial Statements. As a result of discontinuing hedge accounting effective January 1, 2012, the mark-to-market value of all commodity hedge instruments within accumulated other comprehensive income (“AOCI”) at December 31, 2011 was frozen in AOCI as of the de-designation date and was reclassified into earnings in future periods as the original hedged transactions occurred. All cash flow hedged transactions were completed by December 31, 2014.

The accounting for changes in the fair value of a derivative instrument depends on the intended use of the derivative and the resulting designation, which is established at the inception of a derivative. Before discontinuing cash flow hedge accounting effective January 1, 2012, we were required to formally document, at the inception of a hedge, the hedging relationship and the risk management objective and strategy for undertaking the hedge, including identification of the hedging instrument, the hedged item or transaction, the nature of the risk being hedged, the method that will be used to assess effectiveness and the method that will be used to measure hedge ineffectiveness of derivative instruments that receive hedge accounting treatment.

For derivative instruments that were designated as cash flow hedges, changes in fair value, to the extent the hedge was effective, were recognized in AOCI until the hedged item was recognized in earnings. Hedge effectiveness was assessed quarterly based on total changes in the derivatives’ fair value. Any ineffective portion of the derivative instrument’s change in fair value was recognized immediately in earnings.

Currently, our financial derivative instruments are marked to market with the resulting changes in fair value recorded in earnings. As a result of our election to discontinue cash flow hedge accounting effective January 1, 2012, we reclassified the commodity derivative gain (loss) line item within the Consolidated Statements of Operations from operating and other revenues to other income and expenses, due to the change in the composition of the commodity derivative gain (loss) line item, to include prospective fair value changes of hedge instruments.

The estimates of the fair values of our derivative instruments require substantial judgment. These values are based upon, among other things, option pricing models, futures prices, volatility, time to maturity and credit risk. The values we report in our financial statements change as these estimates are revised to reflect actual results, changes in market conditions or other factors, many of which are beyond our control.

Income Taxes and Uncertain Tax Positions

Income taxes are provided for the tax effects of transactions reported in the financial statements and consist of taxes currently payable plus deferred income taxes related to certain income and expenses recognized in different periods for financial and income tax reporting purposes. Deferred income tax assets and liabilities represent the future tax return consequences of those differences, which will either be taxable or deductible when assets are recovered or liabilities are settled. Deferred income taxes are also recognized for tax credits that are available to offset future income taxes. Deferred income taxes are measured by applying currently enacted tax rates to the differences between financial statement and income tax reporting. We routinely assess the realizability of our deferred tax assets. If we conclude that it is more likely than not that some portion or all of the deferred tax assets will not be realized under accounting standards, the tax asset would be reduced by a valuation allowance. We consider estimated future taxable income in making such assessments. Numerous judgments and assumptions are inherent in the determination of future taxable income, including factors such as future operating conditions (particularly as related to prevailing oil and natural gas prices). There can be no assurance that facts and circumstances will not materially change and require us to establish deferred tax asset valuation allowances in a future period.

Accounting guidance for recognizing and measuring uncertain tax positions prescribes a more likely than not recognition threshold that a tax position must meet for any of the benefit of the uncertain tax position to be recognized in the financial statements. Guidance is also provided regarding de-recognition, classification and disclosure of these uncertain tax positions. Based on this guidance, we regularly analyze tax positions taken or expected to be taken in a tax return based on the threshold prescribed. Tax positions that do not meet or exceed this threshold are considered uncertain tax positions. Penalties, if any, related to uncertain tax positions would be recorded in other expenses. We currently do not have any uncertain tax positions recorded as of December 31, 2014.

We are subject to taxation in many jurisdictions, and the calculation of our tax liabilities involves dealing with uncertainties in the application of complex tax laws and regulations in various taxing jurisdictions. If we ultimately determine that the payment of these liabilities will be unnecessary, we reverse the liability and recognize a tax benefit during the period in which we determine the liability no longer applies. Conversely, we record additional tax charges in a period in which we determine that a recorded tax liability is less than we expect the ultimate assessment to be.

Stock-Based Compensation

We recognize compensation expense for all share-based payment awards made to employees and directors. Stock-based compensation expense is measured at the grant date based on the fair value of the award and is recognized as expense on a straight-line basis over the requisite service period, which is generally the vesting period. Judgments and estimates are made regarding, among other things, the appropriate valuation methodology to follow in valuing stock compensation awards and the related inputs required by those valuation methodologies. The Black-Scholes option-pricing model uses assumptions regarding expected volatility of our common stock, the risk-free interest rates, expected term of the awards and other valuation inputs, which are subject to change. Any such changes could result in different valuations and thus impact the amount of stock-based compensation expense recognized. The Monte Carlo simulation method uses assumptions regarding random projections and must be repeated numerous times to achieve a probable assessment. Any change in inputs or number of inputs to this calculation could impact the valuation and thus the stock-based compensation expense recognized.

We recorded non-cash stock-based compensation expense of $11.0 million, $15.6 million and $16.4 million for the years ended December 31, 2014, 2013 and 2012, respectively, for option grants, option modifications, nonvested equity shares of common stock, nonvested equity shares of common stock units, and nonvested performance-based equity shares of common stock.

New Accounting Pronouncements

In August 2014, the FASB issued ASU 2014-15, *Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern.* The objective of this update is to provide guidance in GAAP about management's responsibility to evaluate whether there is substantial doubt about an entity's ability to continue as a going concern and to provide related footnote disclosures. ASU 2014-15 is effective for the annual period ending after December 15, 2016, and for annual periods and interim periods thereafter. The standard will be adopted prospectively.

In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers.* The objective of this update is to clarify the principles for recognizing revenue and to develop a common revenue standard. ASU 2014-09 is effective for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period. The Company is currently evaluating the potential impact that the adoption will have on the Company's disclosures and financial statements.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk.

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term "market risk" refers to the risk of loss arising from adverse changes in oil, natural gas and NGL prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures. All of our market risk sensitive instruments were entered into for purposes other than speculative trading.

Commodity Price Risk

Our primary market risk exposure is in the prices we receive for our production. Commodity pricing is primarily driven by the prevailing worldwide price for crude oil and spot regional market prices applicable to our U.S. natural gas production. Pricing for oil, natural gas and NGLs has been volatile and unpredictable for several years, and we expect this volatility to continue in the future. For example, the West Texas Intermediate price per Bbl as quoted on the NYMEX was $98.42 per Bbl at December 31, 2013 compared to $53.27 at December 31, 2014. The prices we receive for future production depend on many factors outside of our control, including volatility in the differences between product prices at sales points and the applicable index price. Based on our average daily production and our derivative contracts in place for the year ended December 31, 2014, our annual revenues would have decreased by approximately $0.2 million for each $1.00 per barrel decrease in crude oil prices, $0.3 million for each $0.10 decrease per MMBtu in natural gas prices and $1.1 million for each $1.00 per barrel decrease in NGL prices. We are more susceptible to proved and unproved property impairments due to the current commodity price environment.

We routinely enter into commodity hedges relating to a portion of our projected production revenue through various financial transactions that hedge future prices received. These transactions may include financial price swaps whereby we will receive a fixed price and pay a variable market price to the contract counterparty. These commodity hedging activities are intended to support oil, natural gas and NGL prices at targeted levels that provide an acceptable rate of return and to manage our exposure to oil, natural gas and NGL price fluctuations.

As of January 27, 2015, we have financial derivative instruments related to oil, natural gas and NGL volumes in place for the following periods indicated. Further detail of these hedges is summarized in the table presented under “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Capital Resources and Liquidity—Commodity Hedging Activities”.

	For the year 2015	For the year 2016	For the year 2017
Oil (Bbls)	4,022,600	1,737,000	365,000
Natural Gas (MMbtu)	7,207,000	1,830,000	—

Interest Rate Risks

At December 31, 2014, we had no amounts outstanding under our Amended Credit Facility, which bears interest at floating rates. The average annual interest rate incurred on this debt for the year ended December 31, 2014 was 1.9%. A 1.0% increase in each of the average LIBOR rate and federal funds rate for the year ended December 31, 2014 would have resulted in an estimated $1.6 million increase in interest expense assuming a similar average debt level to the year ended December 31, 2014. The average annual interest rate incurred on this debt for the year ended December 31, 2013 was 2.0%. A 1.0% increase in each of the average LIBOR rate and federal funds rate for the year ended December 31, 2013 would have resulted in an estimated $1.8 million increase in interest expense assuming a similar average debt level to the year ended December 31, 2013. We also had $25.3 million principal amount of Convertible Notes (with a fixed cash interest rate of 5%), $400.0 million principal amount of 7.625% Senior Notes, $400.0 million principal amount of 7.0% Senior Notes and $3.6 million principal amount of 3.3% Lease Financing Obligation outstanding at December 31, 2014.

Item 8. Financial Statements and Supplementary Data.

The information required by this item is included below in “Item 15. Exhibits, Financial Statement Schedules”.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.

None.

Item 9A. Controls and Procedures.

Evaluation of Disclosure Controls and Procedures. As of December 31, 2014, we carried out an evaluation, under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rules 13a-15 and 15d-15 of the Securities Exchange Act of 1934 (the “Exchange Act”). Based upon that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures are effective as of December 31, 2014.

Management’s Report on Internal Control Over Financial Reporting. Our management is responsible for establishing and maintaining internal control over financial reporting. Our internal control over financial reporting is a process designed under the supervision of the Chief Executive Officer and Chief Financial Officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Management assessed the effectiveness of our internal control over financial reporting. In making this assessment, it used the criteria set forth by the Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our assessment we have concluded that, as of December 31, 2014, our internal control over financial reporting is effective.

Our independent registered public accounting firm has issued an attestation report on our internal control over financial reporting. That report is set forth below.

Changes in Internal Controls. There has been no change in our internal control over financial reporting during the fourth fiscal quarter of 2014 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Bill Barrett Corporation
Denver, Colorado

We have audited the internal control over financial reporting of Bill Barrett Corporation and subsidiaries (the "Company") as of December 31, 2014, based on criteria established in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management's Report on Internal Control Over Financial Reporting*. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on the criteria established in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2014 of the Company and our report dated February 26, 2015 expressed an unqualified opinion on those financial statements.

/s/ Deloitte & Touche LLP

Denver, Colorado
February 26, 2015

Item 9B. Other Information.

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance.

The information required by this item will be included in an amendment to this Form 10-K or in the "Directors and Executive Officers" section, the "Section 16(a) Beneficial Ownership Reporting Compliance" section, the "Code of Business Conduct and Ethics" section and the "Corporate Governance" section of the proxy statement for the 2015 annual meeting of stockholders, in either case, to be filed within 120 days after December 31, 2014, and is incorporated by reference to this report.

Item 11. Executive Compensation.

The information required by this item will be included in an amendment to this Form 10-K or in the "Executive Compensation" section and the "Director Compensation" section of the proxy statement for the 2015 annual meeting of stockholders, in either case, to be filed within 120 days after December 31, 2014, and is incorporated by reference to this report.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.

Information regarding beneficial ownership will be included in an amendment to this Form 10-K or in the "Beneficial Owners of Securities" section of the proxy statement for the 2015 annual meeting of stockholders, in either case, to be filed within 120 days after December 31, 2014, and is incorporated by reference to this report.

Equity Compensation Plan Information

The following table provides aggregate information presented as of December 31, 2014 with respect to all compensation plans under which equity securities are authorized for issuance.

Plan Category	(a) Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights	(b) Weighted Averaged Exercise Price of Outstanding Options, Warrants and Rights	(c) Number of Securities Remaining Available for Future Issuance (Excluding Securities Reflected in Column (a))
Equity compensation plans approved by shareholders	1,339,365	$32.47(1)	1,843,748
Equity compensation plans not approved by shareholders	—	—	—
Total	1,339,365	$32.47	1,843,748

(1) The weighted average exercise price relates to the 1,339,365 outstanding options included in column (a).

Item 13. Certain Relationships and Related Transactions and Director Independence.

The information required by this item will be included in an amendment to this Form 10-K or in the "Approval of Related Party Transactions" section and the "Corporate Governance" section of the proxy statement for the 2015 annual meeting of stockholders, in either case, to be filed within 120 days after December 31, 2014, and is incorporated by reference to this report.

Item 14. Principal Accounting Fees and Services.

The information required by this item will be included in an amendment to this Form 10-K or in the "Fees to Independent Auditors" section of the proxy statement for the 2015 annual meeting of stockholders, in either case, to be filed within 120 days after December 31, 2014, and is incorporated by reference to this report.

PART IV

Item 15. Exhibits, Financial Statement Schedules.

(a)(1) and (a)(2) Financial Statements and Financial Statement Schedules.

All schedules are omitted because the required information is not applicable or is not present in amounts sufficient to require submission of the schedule or because the information required is included in the Consolidated Financial Statements and Notes thereto.

(a)(3) Exhibits.

Exhibit Number	Description of Exhibits
2.1	Purchase and Sale Agreement dated October 31, 2012 between Bill Barrett Corporation and Bill Barrett CBM Corporation, as Sellers, Encore Energy Partners Operating, LLC, as Buyer, and Vanguard Natural Resources LLC as Parent Guarantor. [Incorporated by reference to Exhibit 2 of our Current Report on Form 8-K filed with the Commission on November 5, 2012.]
2.2	Purchase and Sale Agreement, dated October 22, 2013, among Bill Barrett Corporation, Enervest Energy Institutional Fund XIII-A, L.P., Enervest Energy Institutional Fund XIII-WIB, L.P. and Enervest Energy Institutional Fund XIII-WIC, L.P. [Incorporated by reference to Exhibit 2 of our Current Report on Form 8-K filed with the Commission on October 25, 2013.]; as amended by the Amendment to Purchase and Sale Agreement, dated December 10, 2013, among Bill Barrett Corporation, Enervest Energy Institutional Fund XIII-A, L.P., Enervest Energy Institutional Fund XIII-WIB, L.P. and Enervest Energy Institutional Fund XIII-WIC, L.P. [Incorporated by reference to Exhibit 2.1 of our Current Report on Form 8-K filed with the Commission on December 11, 2013.] Purchase and Sale Agreement dated September 15, 2014 among Bill Barrett Corporation, Vanguard Operating, LLC and Vanguard Natural Resources, LLC. [Incorporated by reference to Exhibit 2.1 of our Current Report on Form 8-K filed with the Commission on October 3, 2014.]
3.1	Restated Certificate of Incorporation of Bill Barrett Corporation. [Incorporated by reference to Appendix A to our Definitive Proxy Statement filed with the Commission on April 4, 2012.]
3.2	Bylaws of Bill Barrett Corporation. [Incorporated by reference to Exhibit 3.2 of our Current Report on Form 8-K filed with the Commission on May 15, 2012.]

Exhibit Number	Description of Exhibits
4.1(a)	Specimen Certificate of Common Stock. [Incorporated by reference to Exhibit 4.1 of Amendment No. 1 to our Registration Statement on Form 8-A filed with the Commission on December 20, 2004.]
4.1(b)	Indenture, dated March 12, 2008, between Bill Barrett Corporation and Deutsche Bank Trust Company Americas, as Trustee. [Incorporated by reference to Exhibit 4.1 of our Current Report on Form 8-K filed with the Commission on March 12, 2008.]
4.1(c)	Indenture, dated July 8, 2009, between Bill Barrett Corporation and Deutsche Bank Trust Company Americas, as Trustee. [Incorporated by reference to Exhibit 4.1 of our Current Report on Form 8-K filed with the Commission on July 8, 2009.]
4.2(a)	Registration Rights Agreement, dated March 28, 2002, among Bill Barrett Corporation and the investors named therein. [Incorporated by reference to Exhibit 4.2 of Amendment No. 2 to our Registration Statement on Form S-1 (Registration No. 333-114554) filed with the Commission on August 31, 2004.]
4.2(b)	First Supplemental Indenture, dated March 12, 2008, by and between Bill Barrett Corporation and Deutsche Bank Trust Company Americas, as Trustee (including form of 5% Convertible Senior Notes due 2028). [Incorporated by reference to Exhibit 4.2 of our Current Report on Form 8-K filed with the Commission on March 12, 2008.]
4.3(a)	Stockholders' Agreement, dated March 28, 2002 and as amended to date, among Bill Barrett Corporation and the investors named therein. [Incorporated by reference to Exhibit 4.3 to Amendment No. 2 to our Registration Statement on Form S-1 (Registration No. 333-114554) filed with the Commission on August 31, 2004.]
4.3(b)	Second Supplemental Indenture, dated July 8, 2009, by Bill Barrett Corporation, Bill Barrett CBM Corporation, Bill Barrett CBM LLC, Circle B Land Company LLC and Deutsche Bank Trust Company Americas, as Trustee (including form of 9.875% Senior Notes due 2016). [Incorporated by reference to Exhibit 4.3 of our Current Report on Form 8-K with the Commission on July 8, 2009.]
4.3(c)	Third Supplemental Indenture, dated September 27, 2011, by Bill Barrett Corporation, Bill Barrett CBM Corporation, Bill Barrett CBM LLC, Circle B Land Company LLC, GB Acquisition Corporation, Elk Production, LLC, Aurora Gathering, LLC and Deutsche Bank Trust Company Americas, as Trustee (including form of 7.625% Senior Notes due 2019). [Incorporated by reference to Exhibit 4.2 of our Current Report on Form 8-K with the Commission on September 27, 2011.]
4.3(d)	Fourth Supplemental Indenture for the Company's 7% Senior Notes due 2022, dated March 12, 2012, among the Company, the Subsidiary Guarantors and the Trustee [Incorporated by reference to Exhibit 4.2 of our Current Report on Form 8-K filed with the Commission March 12, 2012.]
10.1(a)	Third Amended and Restated Credit Agreement, dated as of March 16, 2010, among Bill Barrett Corporation and the banks named therein. [Incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed with the Commission on March 17, 2010.]
10.1(b)	First Amendment to Third Amended and Restated Credit Agreement dated as of October 18, 2011 among Bill Barrett Corporation and the banks named therein. [Incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed with the Commission on October 18, 2011.]

Exhibit Number	Description of Exhibits
10.1(c)	Second Amendment dated effective as of September 30, 2014 to Third Amended and Restated Credit Agreement dated as of March 16, 2010, among Bill Barrett Corporation and the banks named therein. [Incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed with the Commission on December 11, 2014.]
10.2*	Form of Indemnification Agreement, between Bill Barrett Corporation and each of the directors and certain executive officers of the Company. [Incorporated by reference to Exhibit 10.10(a) to Amendment No. 2 to our Registration Statement on Form S-1 (Registration No. 333-114554) filed with the Commission on August 31, 2004.]
10.3*	Amended and Restated 2002 Stock Option Plan. [Incorporated by reference to Exhibit 10.12 to Amendment No. 2 to our Registration Statement on Form S-1 (Registration No. 333-114554) filed with the Commission on August 31, 2004.]
10.4(a)*	Form of Tranche A Stock Option Agreement for 2002 Stock Option Plan. [Incorporated by reference to Exhibit 10.13(a) to Amendment No. 4 to our Registration Statement on Form S-1 (Registration No. 333-114554) filed with the Commission on October 13, 2004.]
10.4(b)*	Form of Tranche B Stock Option Agreement for 2002 Stock Option Plan. [Incorporated by reference to Exhibit 10.13(b) to Amendment No. 4 to our Registration Statement on Form S-1 (Registration No. 333-114554) filed with the Commission on October 13, 2004.]
10.5*	2003 Stock Option Plan. [Incorporated by reference to Exhibit 10.14 to Amendment No. 3 to our Registration Statement on Form S-1 (Registration No. 333-114554) filed with the Commission on September 22, 2004.]
10.6*	Form of Stock Option Agreement for 2003 Stock Option Plan. [Incorporated by reference to Exhibit 10.15 to Amendment No. 4 to our Registration Statement on Form S-1 (Registration No. 333-114554) filed with the Commission on October 13, 2004.]
10.7*	2004 Stock Incentive Plan. [Incorporated by reference to Exhibit 10.21 to Amendment No. 4 to our Registration Statement on Form S-1 (Registration No. 333-114554) filed with the Commission on October 13, 2004.]
10.8*	Revised Form of Stock Option Agreement for 2004 Stock Option Plan. [Incorporated by reference to Exhibit 10.19 to our Annual Report on Form 10-K for the year ended December 31, 2005.]
10.9*	Form of Restricted Common Stock Award Agreement for 2004 Stock Incentive Plan. [Incorporated by reference to Exhibit 10-19 to our Annual Report on Form 10-K for the year ended December 31, 2005.]
10.10(a)*	Form of Performance Vesting Restricted Stock Agreement for 2004 Stock Incentive Plan. [Incorporated by reference to Exhibit 10-19 to our Annual Report on Form 10-K for the year ended December 31, 2005.]
10.10(b)*	Form of Performance Vesting Restricted Stock Agreement for 2004 Stock Incentive Plan (2009 Temporary Supplemental Grant). [Incorporated by reference to Exhibit 10.14(b) to our Quarterly Report on Form 10-Q for the three months ended March 31, 2009.]
10.11*	2008 Stock Incentive Plan. [Incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed with the Commission on May 16, 2008.]
10.12*	Form of Stock Option Agreement for 2008 Stock Incentive Plan. [Incorporated by reference to Exhibit 10.16 to our Annual Report on Form 10-K for the year ended December 31, 2008.]

Exhibit Number	Description of Exhibits
10.13*	Severance Plan. [Incorporated by reference to Exhibit 10.23 to Amendment No. 4 to our Registration Statement on Form S-1 (Registration No. 333-114554) filed with the Commission on October 13, 2004.]
10.14*	2012 Equity Incentive Plan. [Incorporated by reference to Appendix B to our Definitive Proxy Statement filed with the Commission on April 4, 2012.]
10.15*	Form of Restricted Common Stock Unit Award for 2012 Equity Incentive Plan. [Incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K filed with the Commission on July 2, 2012.]
10.16*	Succession Agreement with Fredrick J. Barrett, dated January 9, 2013. [Incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed with the Commission on January 9, 2013.]
10.17*	Succession Agreement with Kurt M. Reinecke, dated January 30, 2013. [Incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed with the Commission on January 31, 2013.]
10.18*	Form of Amended and Restated Change in Control Severance Protection Agreement. [Incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed with the Commission on January 30, 2015.]
12.1**	Computation of Ratio of Earnings to Fixed Charges
21.1**	Subsidiaries of the Registrant.
23.1**	Consent of Deloitte & Touche LLP.
23.2**	Consent of Netherland, Sewell & Associates, Inc., Independent Petroleum Engineers.
31.1**	Rule 13a-14(a)/15d-14(a) Certification of Chief Executive Officer.
31.2**	Rule 13a-14(a)/15d-14(a) Certification of Chief Financial Officer.
32***	Section 1350 Certification of Chief Executive Officer and Chief Financial Officer.
99.1**	Report of Netherland, Sewell & Associates, Inc. dated January 14, 2014, concerning audit of oil and gas reserve estimates.
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema Document
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB	XBRL Taxonomy Extension Label Linkbase Document
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document

* Indicates a management contract or compensatory plan or arrangement, as required by Item 15(a)(3).
** Filed herewith.
*** Furnished herewith.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

BILL BARRETT CORPORATION

Date: February 26, 2015

By: /s/ R. Scot Woodall
R. Scot Woodall
Chief Executive Officer and President

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ R. Scot Woodall **R. Scot Woodall**	Chief Executive Officer, President, and Director (Principal Executive Officer)	February 26, 2015
/s/ Robert W. Howard **Robert W. Howard**	Chief Financial Officer and Treasurer (Principal Financial Officer)	February 26, 2015
/s/ David R. Macosko **David R. Macosko**	Senior Vice President—Accounting (Principal Accounting Officer)	February 26, 2015
/s/ Carin M. Barth **Carin M. Barth**	Director	February 26, 2015
/s/ William F. Owens **William F. Owens**	Director	February 26, 2015
/s/ Kevin O. Meyers **Kevin O. Meyers**	Director	February 26, 2015
/s/ Jim W. Mogg **Jim W. Mogg**	Director	February 26, 2015
/s/ Edmund P. Segner, III **Edmund P. Segner, III**	Director	February 26, 2015
/s/ Randy I. Stein **Randy I. Stein**	Director	February 26, 2015
/s/ Michael E. Wiley **Michael E. Wiley**	Director	February 26, 2015

FINANCIAL STATEMENTS

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Bill Barrett Corporation
Denver, Colorado

We have audited the accompanying consolidated balance sheets of Bill Barrett Corporation and subsidiaries (the "Company") as of December 31, 2014 and 2013, and the related consolidated statements of operations, comprehensive income (loss), cash flows, and stockholders' equity for each of the three years in the period ended December 31, 2014. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Bill Barrett Corporation and subsidiaries as of December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2014, based on the criteria established in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 26, 2015 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Denver, Colorado
February 26, 2015

BILL BARRETT CORPORATION

CONSOLIDATED BALANCE SHEETS

	As of December 31, 2014	As of December 31, 2013
	(in thousands, except share data)	
Assets:		
Current assets:		
Cash and cash equivalents	$ 165,904	$ 54,595
Accounts receivable, net of allowance for doubtful accounts	112,209	97,586
Derivative assets	145,226	173
Prepayments and other current assets	2,766	4,893
Total current assets	426,105	157,247
Property and equipment—at cost, successful efforts method for oil and gas properties:		
Proved oil and gas properties	2,009,292	2,863,923
Unproved oil and gas properties, excluded from amortization	148,834	246,433
Oil and gas properties held for sale, net of amortization and impairment	9,234	—
Furniture, equipment and other	39,963	41,726
	2,207,323	3,152,082
Accumulated depreciation, depletion, amortization and impairment	(454,202)	(949,586)
Total property and equipment, net	1,753,121	2,202,496
Derivative assets	49,750	2,539
Deferred financing costs and other noncurrent assets	15,508	19,231
Total	$2,244,484	$2,381,513
Liabilities and Stockholders' Equity:		
Current liabilities:		
Accounts payable and accrued liabilities	$ 126,252	$ 115,928
Amounts payable to oil and gas property owners	19,187	26,778
Production taxes payable	38,060	39,235
Derivative liabilities	—	5,988
Deferred income taxes	55,418	199
Current portion of long-term debt	25,770	4,591
Total current liabilities	264,687	192,719
Long-term debt	803,222	979,082
Asset retirement obligations	21,592	39,200
Liabilities associated with assets held for sale	146	—
Deferred income taxes	122,350	161,326
Derivatives and other noncurrent liabilities	2,999	3,468
Stockholders' equity:		
Common stock, $0.001 par value; authorized 150,000,000 shares; 49,526,637 and 49,152,448 shares issued and outstanding at December 31, 2014 and 2013, respectively, with 1,407,141 and 1,340,060 shares subject to restrictions, respectively	48	48
Additional paid-in capital	913,619	904,261
Retained earnings	115,821	100,740
Treasury stock, at cost: zero shares at December 31, 2014 and 2013	—	—
Accumulated other comprehensive income	—	669
Total stockholders' equity	1,029,488	1,005,718
Total	$2,244,484	$2,381,513

See notes to Consolidated Financial Statements.

BILL BARRETT CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2014	2013	2012
	(in thousands, except share and per share data)		
Operating and Other Revenues:			
Oil, gas and NGL production	$ 464,137	$ 565,555	$ 700,639
Other	8,154	2,538	(444)
Total operating and other revenues	472,291	568,093	700,195
Operating Expenses:			
Lease operating expense	60,308	70,217	72,734
Gathering, transportation and processing expense	35,437	67,269	106,548
Production tax expense	31,333	27,172	25,513
Exploration expense	453	337	8,814
Impairment, dry hole costs and abandonment expense	46,881	238,398	67,869
Loss on divestitures	100,407	—	—
Depreciation, depletion and amortization	235,805	279,775	326,842
Unused commitments	4,434	—	—
General and administrative expense	53,361	64,902	68,666
Total operating expenses	568,419	748,070	676,986
Operating Income (Loss)	(96,128)	(179,977)	23,209
Other Income and Expense:			
Interest and other income	1,294	1,646	155
Interest expense	(69,623)	(88,507)	(95,506)
Commodity derivative gain (loss)	197,447	(23,068)	72,759
Gain (loss) on extinguishment of debt	—	(21,460)	1,601
Total other income and expense	129,118	(131,389)	(20,991)
Income (Loss) before Income Taxes	32,990	(311,366)	2,218
Provision for (Benefit from) Income Taxes	17,909	(118,633)	1,636
Net Income (Loss)	$ 15,081	$ (192,733)	$ 582
Net Income (Loss) Per Common Share, Basic	$ 0.31	$ (4.06)	$ 0.01
Net Income (Loss) Per Common Share, Diluted	$ 0.31	$ (4.06)	$ 0.01
Weighted Average Common Shares Outstanding, Basic	48,010,730	47,496,857	47,194,668
Weighted Average Common Shares Outstanding, Diluted	48,435,725	47,496,857	47,353,951

See notes to Consolidated Financial Statements.

BILL BARRETT CORPORATION

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Year Ended December 31,		
	2014	2013	2012
		(in thousands)	
Net Income (Loss)	$15,081	$(192,733)	$ 582
Other Comprehensive Loss, net of tax:			
Effect of derivative financial instruments	(669)	(4,663)	(50,712)
Other comprehensive loss	(669)	(4,663)	(50,712)
Comprehensive Income (Loss)	$14,412	$(197,396)	$(50,130)

See notes to Consolidated Financial Statements.

BILL BARRETT CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2014	2013	2012
		(in thousands)	
Operating Activities:			
Net Income (Loss)	$ 15,081	$(192,733)	$ 582
Adjustments to reconcile to net cash provided by operations:			
Depreciation, depletion and amortization	235,805	279,775	326,842
Deferred income taxes	16,644	(117,050)	(185)
Impairment, dry hole costs and abandonment expense	46,881	238,398	67,869
Commodity derivative (gain) loss	(197,447)	23,068	(72,759)
Settlements of commodity derivatives	(1,888)	5,315	42,305
Stock compensation and other non-cash charges	11,352	16,027	18,328
Amortization of debt discounts and deferred financing costs	4,264	5,604	8,425
(Gain) loss on extinguishment of debt	—	21,460	(1,601)
(Gain) loss on sale of properties	100,407	(130)	4,279
APIC pool for excess tax benefits related to share-based compensation	—	1,259	(32)
Change in operating assets and liabilities:			
Accounts receivable	32,163	14,294	(10,511)
Prepayments and other assets	1,643	1,394	1,293
Accounts payable, accrued and other liabilities	5,119	(35,600)	2,589
Amounts payable to oil and gas property owners	(7,132)	9,997	3,988
Production taxes payable	(1,175)	(5,813)	(2,976)
Net cash provided by operating activities	261,717	265,265	388,436
Investing Activities:			
Additions to oil and gas properties, including acquisitions	(580,943)	(445,479)	(958,654)
Additions of furniture, equipment and other	(3,658)	(2,254)	(7,231)
Proceeds from sale of properties and other investing activities	555,296	310,704	328,888
Net cash used in investing activities	(29,305)	(137,029)	(636,997)
Financing Activities:			
Proceeds from debt	165,000	420,000	875,826
Principal and redemption premium payments on debt	(283,546)	(576,422)	(595,386)
Proceeds from stock option exercises	126	6,385	673
APIC pool for excess tax benefits related to share-based compensation	—	(1,259)	—
Deferred financing costs and other	(2,683)	(1,790)	(10,438)
Net cash provided by (used in) financing activities	(121,103)	(153,086)	270,675
Increase (Decrease) in Cash and Cash Equivalents	111,309	(24,850)	22,114
Beginning Cash and Cash Equivalents	54,595	79,445	57,331
Ending Cash and Cash Equivalents	$ 165,904	$ 54,595	$ 79,445

See notes to Consolidated Financial Statements.

BILL BARRETT CORPORATION

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

(In thousands)

	Common Stock	Additional Paid-In Capital	Retained Earnings	Treasury Stock	Accumulated Other Comprehensive Income	Total Stockholders' Equity
Balance at December 31, 2011	$ 47	$869,856	$ 292,891	$ —	$ 56,044	$1,218,838
Exercise of options, restricted stock activity and shares exchanged for exercise and tax withholding	—	673	—	(2,513)	—	(1,840)
APIC pool for excess tax benefits related to share-based compensation	—	32	—	—	—	32
Stock-based compensation	—	16,874	—	—	—	16,874
Retirement of treasury stock	—	(2,513)	—	2,513	—	—
Settlement of convertible notes	—	(999)	—	—	—	(999)
Net income	—	—	582	—	—	582
Effect of derivative financial instruments, net of $30,458 of taxes	—	—	—	—	(50,712)	(50,712)
Balance at December 31, 2012	$ 47	$883,923	$ 293,473	$ —	$ 5,332	$1,182,775
Exercise of options, restricted stock activity and shares exchanged for exercise and tax withholding	1	6,384	—	(1,778)	—	4,607
APIC pool for excess tax benefits related to share-based compensation	—	(1,259)	—	—	—	(1,259)
Stock-based compensation	—	16,991	—	—	—	16,991
Retirement of treasury stock	—	(1,778)	—	1,778	—	—
Net loss	—	—	(192,733)	—	—	(192,733)
Effect of derivative financial instruments, net of $2,802 of taxes	—	—	—	—	(4,663)	(4,663)
Balance at December 31, 2013	$ 48	$904,261	$ 100,740	$ —	$ 669	$1,005,718
Exercise of options, restricted stock activity and shares exchanged for exercise and tax withholding	—	126	—	(2,684)	—	(2,558)
Stock-based compensation	—	11,916	—	—	—	11,916
Retirement of treasury stock	—	(2,684)	—	2,684	—	—
Net income	—	—	15,081	—	—	15,081
Effect of derivative financial instruments, net of $410 of taxes	—	—	—	—	(669)	(669)
Balance at December 31, 2014	$ 48	$913,619	$ 115,821	$ —	$ —	$1,029,488

See notes to Consolidated Financial Statements.

1. Organization

Bill Barrett Corporation, a Delaware corporation, together with its wholly-owned subsidiaries (collectively, the "Company") is an independent oil and gas company engaged in the exploration, development and production of oil, natural gas and NGLs. Since its inception in January 2002, the Company has conducted its activities principally in the Rocky Mountain region of the United States.

2. Summary of Significant Accounting Policies

Basis of Presentation. The accompanying Consolidated Financial Statements include the accounts of the Company. These statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP"). All intercompany accounts and transactions have been eliminated in consolidation.

Use of Estimates. In the course of preparing the Company's financial statements in accordance with GAAP, management makes various assumptions, judgments and estimates to determine the reported amount of assets, liabilities, revenues and expenses and in the disclosure of commitments and contingencies. Changes in these assumptions, judgments and estimates will occur as a result of the passage of time and the occurrence of future events and, accordingly, actual results could differ from amounts initially established.

Areas requiring the use of assumptions, judgments and estimates relate to the expected cash settlement of the Company's 5% Convertible Senior Notes due 2028 ("Convertible Notes") in computing diluted earnings per share, volumes of oil, natural gas and NGL reserves used in calculating depreciation, depletion and amortization ("DD&A"), the amount of expected future cash flows used in determining possible impairments of oil and gas properties and the amount of future capital costs used in these calculations. Assumptions, judgments and estimates also are required in determining asset retirement obligations, the timing of dry hole costs, impairments of proved and unproved properties, valuing deferred tax assets and estimating fair values of derivative instruments and stock-based payment awards.

Accounts Receivable. Accounts receivable is comprised of the following:

	As of December 31,	
	2014	2013
	(in thousands)	
Accrued oil, gas and NGL sales	$ 35,099	$67,583
Due from joint interest owners	27,937	23,507
Other (1)	49,187	6,517
Allowance for doubtful accounts	(14)	(21)
Total accounts receivable	$112,209	$97,586

(1) Other includes a receivable of $47.6 million (including $4.7 million due to another industry partner) related to a settlement agreement with the Department of Interior ("DOI") resulting in the cancellation of certain Cottonwood Gulch natural gas leases during the three months ended December 31, 2014.

Cash and Cash Equivalents. The Company considers all highly liquid investments with a remaining maturity of three months or less when purchased to be cash equivalents.

Oil and Gas Properties. The Company's oil, gas and NGL exploration and production activities are accounted for using the successful efforts method. Under this method, all property acquisition costs and costs of exploratory and development wells are capitalized when incurred, pending determination of whether the well has found proved reserves. If an exploratory well does not find proved reserves, the costs of drilling the well are charged to expense and included within cash flows from investing activities in the Consolidated Statements of Cash Flows. If an exploratory well does find proved reserves, the costs remain capitalized and are included within additions to oil and gas properties within cash flows from investing activities in the Consolidated Statements of Cash Flows when paid. The costs of development wells are capitalized whether proved reserves are added or not. Oil and gas lease acquisition costs are also capitalized. Upon sale or retirement of depreciable or depletable property, the cost and related accumulated DD&A are eliminated from the accounts and the resulting gain or loss is recognized.

Other exploration costs, including certain geological and geophysical expenses and delay rentals for oil and gas leases, are charged to expense as incurred. The sale of a partial interest in a proved property is accounted for as a cost recovery and no gain or loss is recognized as long as this treatment does not significantly affect the unit-of-production amortization rate. Maintenance and repairs are charged to expense, and renewals and betterments are capitalized to the appropriate property and equipment accounts.

Unproved oil and gas property costs are transferred to proved oil and gas properties if the properties are subsequently determined to be productive or are assigned proved reserves. Proceeds from sales of partial interests in unproved leases are accounted for as a recovery of cost without recognizing any gain until all costs are recovered. Unproved oil and gas properties are assessed periodically for impairment based on remaining lease terms, drilling results, reservoir performance, commodity price outlooks, future plans to develop acreage and other relevant matters.

Materials and supplies consist primarily of tubular goods and well equipment to be used in future drilling operations or repair operations and are carried at the lower of cost or market value, on a first-in, first-out basis.

The following table sets forth the net capitalized costs and associated accumulated DD&A and non-cash impairments relating to the Company's oil, natural gas and NGL producing activities:

	As of December 31,	
	2014	2013
	(in thousands)	
Proved properties	$ 390,482	$ 485,427
Wells and related equipment and facilities	1,537,370	2,192,754
Support equipment and facilities	68,371	177,224
Materials and supplies	13,069	8,518
Total proved oil and gas properties	$2,009,292	$2,863,923
Unproved properties	78,898	189,759
Wells and facilities in progress	69,936	56,674
Total unproved oil and gas properties, excluded from amortization	$ 148,834	$ 246,433
Assets held for sale	9,234	—
Accumulated depreciation, depletion, amortization and impairment	(427,954)	(926,173)
Total oil and gas properties, net	$1,739,406	$2,184,183

All exploratory wells are evaluated for economic viability within one year of well completion. Exploratory wells that discover potentially economic reserves in areas where a major capital expenditure would be required before production could begin, and where the economic viability of that major capital expenditure depends upon the successful completion of further exploratory work in the area, remain capitalized if the well finds a sufficient quantity of reserves to justify its completion as a producing well and the Company is making sufficient progress assessing the reserves and the economic and operating viability of the project. As of December 31, 2014 and 2013, there were no exploratory well costs that had been capitalized for a period greater than one year since the completion of drilling.

The Company reviews proved oil and gas properties on a field-by-field basis for impairment on a quarterly basis or whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. The Company estimates the expected undiscounted future cash flows of its oil and gas properties and compares such undiscounted future cash flows to the carrying amount of the oil and gas properties to determine if the carrying amount is recoverable. If the carrying value of a property exceeds the undiscounted future cash flows, the Company will impair the carrying value to fair value based on an analysis of quantitative and qualitative factors. The Company has no guarantee that the undiscounted future cash flows analysis of its proved property represents the applicable market value. The factors used to determine fair value include, but are not limited to, recent sales prices of comparable properties, the present value of future revenues, net of estimated operating and development costs using estimates of reserves, future commodity pricing, future production estimates, anticipated capital expenditures and various discount rates commensurate with the risk and current market conditions associated with realizing the expected cash flows projected.

The Company recognized non-cash impairment charges, which were included within impairment, dry hole costs and abandonment expense in the Consolidated Statements of Operations, as follows:

	Year Ended December 31,		
	2014	2013	2012
		(in thousands)	
Non-cash impairment of proved oil and gas properties	$15,761 (1)	$206,953 (3)	$ —
Non-cash impairment of unproved oil and gas properties	24,082 (2)	19,598 (3)	37,348 (4)
Non-cash impairment of inventory	340	—	—
Dry hole costs	101	1,124	21,012
Abandonment expense	6,597	10,723	9,509
Total non-cash impairment, dry hole costs and abandonment expense	$46,881	$238,398	$67,869

(1) As a result of the Powder River Oil Divestiture (see Note 4), the carrying values of the remaining properties were analyzed relative to their estimated fair market value. As a result, the Company recognized impairment of $14.8 million. These properties were classified as held for sale as of December 31, 2014. The remaining impairment of $1.0 million related to the West Tavaputs Divestiture (see Note 4) based upon a true up of previously estimated carrying value.

(2) As a result of unfavorable drilling and completion results in the Paradox Basin, the Company recognized an impairment of $11.6 million related to unproved oil and gas properties. In addition, the Company recognized an impairment of $6.1 million related to certain unproved oil and gas properties in the Uinta Basin as a result of no future plans to evaluate certain acreage positions. The Company recognized an impairment of $6.4 million to unproved oil and gas properties as the result of the Powder River Oil Divestiture discussed in (1) above.

(3) As a result of an analysis of remaining carrying values relative to fair market values resulting from the West Tavaputs Divestiture (see Note 4), $207.0 million and $2.5 million of proved and unproved property impairment, respectively, was incurred during the year ended December 31, 2013. As a result of no future plans to evaluate remaining acreage and estimated market value below carrying value within various exploration projects, an additional $17.1 million of unproved property impairment was incurred during the year ended December 31, 2013.
(4) As a result of unfavorable natural gas exploratory results, no future plans to evaluate remaining acreage and estimated market value below our carrying value within exploration projects, $37.3 million of unproved property impairment was incurred during the year ended December 31, 2012.

The provision for DD&A of oil and gas properties is calculated on a field-by-field basis using the unit-of-production method. Natural gas and NGLs are converted to an oil equivalent, Boe, at the standard rate of six Mcf to one Boe and forty-two gallons to one Boe, respectively. Estimated future dismantlement, restoration and abandonment costs are taken into consideration by this calculation.

Accounts Payable and Accrued Liabilities. Accounts payable and accrued liabilities are comprised of the following:

	As of December 31, 2014	As of December 31, 2013
	(in thousands)	
Accrued drilling, completion and facility costs	$ 68,124	$ 54,750
Accrued lease operating, gathering, transportation and processing expenses	12,526	17,317
Accrued general and administrative expenses	8,482	14,605
Accrued interest payable	14,284	14,860
Accrued payables for property sales	16,296	2,905
Trade payables and other	6,540	11,491
Total accounts payable and accrued liabilities	$126,252	$115,928

Environmental Liabilities. Environmental expenditures that relate to an existing condition caused by past operations and that do not contribute to current or future revenue generation are expensed. Environmental liabilities are accrued when environmental assessments and/or clean-ups are probable, and the costs can be reasonably estimated.

Revenue Recognition. Oil, gas and NGL revenues are recognized when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred, and collectability of the revenue is reasonably assured. The Company uses the sales method to account for gas and NGL imbalances. Under this method, revenues are recorded on the basis of gas and NGLs actually sold by the Company. In addition, the Company records revenues for its share of gas and NGLs sold by other owners that cannot be volumetrically balanced in the future due to insufficient remaining reserves. The Company also reduces revenues for other owners' gas and NGLs sold by the Company that cannot be volumetrically balanced in the future due to insufficient remaining reserves. The Company's remaining over- and under- produced gas and NGLs balancing positions are taken into account in determining the Company's proved oil, gas and NGL reserves. Imbalances at December 31, 2014 and 2013 were not material.

Derivative Instruments and Hedging Activities. The Company periodically uses derivative financial instruments to achieve a more predictable cash flow from its oil, natural gas and NGL sales by reducing its exposure to price fluctuations. Derivative instruments are recorded at fair market value and are included in the Consolidated Balance Sheets as assets or liabilities.

Income Taxes. Income taxes are provided for the tax effects of transactions reported in the financial statements and consist of taxes currently payable plus deferred income taxes related to certain income and expenses recognized in different periods for financial and income tax reporting purposes. Deferred income tax assets and liabilities represent the future tax return consequences of those differences, which will either be taxable or deductible when assets are recovered or liabilities are settled. Deferred income taxes also include tax credits and net operating losses that are available to offset future income taxes. Deferred income taxes are measured by applying currently enacted tax rates.

The Company accounts for uncertainty in income taxes for tax positions taken or expected to be taken in a tax return. Only tax positions that meet the more-likely-than-not recognition threshold are recognized.

Earnings/Loss Per Share. Basic net income (loss) per common share is calculated by dividing net income (loss) attributable to common stock by the weighted average number of common shares outstanding during each period. Diluted net income (loss) per common share is calculated by dividing net income (loss) attributable to common stock by the weighted average number of common shares outstanding and other dilutive securities. Potentially dilutive securities for the diluted net income per common share calculations consist of nonvested equity shares of common stock, in-the-money outstanding stock options to purchase the Company's common stock and shares into which the Convertible Notes are convertible. No potential common shares are included in the computation of any diluted per share amount when a net loss exists, as was the case for the year ended December 31, 2013.

In satisfaction of its obligation upon conversion of the Convertible Notes, the Company may elect to deliver, at its option, cash, shares of its common stock or a combination of cash and shares of its common stock. As of December 31, 2014, the Company expected to settle the remaining Convertible Notes in cash. Therefore, the treasury stock method was used to measure the potentially dilutive impact of shares associated with that remaining conversion feature. The Company has the right at any time with at least 30 days' notice to call the Convertible Notes and the holders have the right to require the Company to purchase the notes on March 20, 2015, March 20, 2018 and March 20, 2023. The Convertible Notes have not been dilutive since their issuance in March 2008 and, therefore, did not impact the diluted net income per common share calculation for the years ended December 31, 2014 and 2012. The diluted net income per common share excludes the anti-dilutive effect of 1,406,938 and 3,162,436 stock options and nonvested equity shares of common stock for the years ended December 31, 2014 and 2012, respectively.

The following table sets forth the calculation of basic and diluted net income (loss) per share:

	Year Ended December 31,		
	2014	2013	2012
	(in thousands, except per share amounts)		
Net income (loss)	$15,081	$(192,733)	$ 582
Basic weighted-average common shares outstanding in period	48,011	47,497	47,195
Add dilutive effects of stock options and nonvested equity shares of common stock	425	—	159
Diluted weighted-average common shares outstanding in period	48,436	47,497	47,354
Basic net income (loss) per common share	$ 0.31	$ (4.06)	$ 0.01
Diluted net income (loss) per common share	$ 0.31	$ (4.06)	$ 0.01

Industry Segment and Geographic Information. The Company operates in one industry segment, which is the development and production of crude oil, natural gas and NGLs, and all of the Company's operations are conducted in the continental United States. Consequently, the Company currently reports as a single industry segment.

New Accounting Pronouncements. In August 2014, the FASB issued ASU 2014-15, *Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern.* The objective of this update is to provide guidance in GAAP about management's responsibility to evaluate whether there is substantial doubt about an entity's ability to continue as a going concern and to provide related footnote disclosures. ASU 2014-15 is effective for the annual period ending after December 15, 2016, and for annual periods and interim periods thereafter. The standard will be adopted prospectively.

In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers.* The objective of this update is to clarify the principles for recognizing revenue and to develop a common revenue standard. ASU 2014-09 is effective for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period. The Company is currently evaluating the potential impact that the adoption will have on the Company's disclosures and financial statements.

Reclassifications. Certain amounts in the prior period Consolidated Balance Sheets have been reclassified to conform to the current period's presentation. During the year ended December 31, 2014, we changed the presentation of unproved oil and gas properties to present unproved oil and gas properties, net of impairment. Impairment of unproved oil and gas properties was included in accumulated depreciation, depletion, amortization and impairment in the prior period. The total property and equipment subtotal was not affected by this reclassification nor were any other financial statements.

3. Supplemental Disclosures of Cash Flow Information

Supplemental cash flow information is as follows:

	Year Ended December 31,		
	2014	2013	2012
		(in thousands)	
Cash paid for interest, net of amount capitalized	$ 65,935	$94,205	$ 83,718
Cash paid for income taxes	1	1,163	10
Supplemental disclosures of non-cash investing and financing activities:			
Accrued receivables—oil and gas properties (1)	42,872	—	—
Accrued liabilities—oil and gas properties	72,297	75,340	49,598
Change in asset retirement obligations, net of disposals	(22,740)	(6,996)	(25,236)
Retirement of treasury stock	2,684	1,778	2,513
Fair value of properties exchanged in non-cash transactions	77,078	—	—
Transfer of lease financing obligation	36,075	45,190	—

(1) Includes a receivable of $42.9 million related to a settlement agreement with the Department of Interior ("DOI") resulting in the cancellation of certain Cottonwood Gulch natural gas leases in 2014.

4. Divestitures and Assets Held for Sale

Divestitures. During the year ended December 31, 2014, the Company completed the sale or exchange of the majority of its Powder River Basin assets (the "Powder River Oil Divestiture") in four separate transactions with effective dates of April 1, 2014 and closing dates during the three months ended September 30, 2014. The sale resulted in net cash proceeds of $30.0 million, after initial closing adjustments. Three transactions involved the cumulative sale of 17,497 net mineral acres. The fourth transaction involved an exchange of 29,015 net mineral acres in the Powder River Basin for 7,856 net mineral acres within the southern block of the Company's operated Northeast Wattenberg area of the Denver-Julesburg Basin, valued at $71.0 million. Assets sold or exchanged as part of the overall Powder River Oil Divestiture included $86.2 million in proved and $40.6 million in unproved oil and gas properties, net of accumulated depreciation, depletion, amortization and impairment of $33.1 million and $1.3 million in asset retirement obligations. A loss on sale of $24.5 million related to these transactions is included within operating expenses in the Consolidated Statements of Operations. The divestiture proceeds are subject to various purchase price adjustments incurred in the normal course of business and will be finalized in 2015.

On September 30, 2014, the Company completed the sale of its Gibson Gulch natural gas program in the Piceance Basin (the "Piceance Divestiture") with an effective date of July 1, 2014. The Company received $498.7 million in cash proceeds, after initial closing estimates. In addition to the cash proceeds, the Company recognized non-cash proceeds of $22.4 million related to the relief of the Company's asset retirement obligation and $36.1 million related to the transfer of the Company's lease financing obligation described in Note 5 (the "Lease Financing Obligation"). A loss on sale of $79.5 million related to this transaction is included within operating expenses in the Consolidated Statements of Operations. The divestiture proceeds are subject to various purchase price adjustments incurred in the normal course of business and will be finalized in 2015. The carrying amounts by major asset class within the disposal group for the Piceance Divestiture are summarized below (in thousands):

Assets:	
Proved properties	$1,320,745
Furniture, equipment and other	4,907
Accumulated depreciation, depletion, amortization and impairment	(688,864)
Total assets	$ 636,788
Liabilities:	
Asset retirement obligation	$ 22,448
Lease financing obligation	36,075
Other liabilities	84
Total liabilities	$ 58,607
Net assets	$ 578,181

On December 10, 2013, the Company completed the sale of its West Tavaputs natural gas assets in the Uinta Basin (the "West Tavaputs Divestiture"). The Company received $308.7 million in cash proceeds, after closing adjustments. The divestiture proceeds were subject to various purchase price adjustments incurred in the normal course of business and were finalized during 2014. The Company recognized an impairment loss of $1.0 million during the year ended December 31, 2014 related to these assets based upon a true up of previously estimated carrying value. An initial impairment loss of $209.5 million related to these assets was recognized during the year ended December 31, 2013.

On December 31, 2012, the Company completed the sale of natural gas assets including 100% of its Wind River Basin, 100% of the Powder River Basin coalbed methane assets, and a non-operating working interest in its Gibson Gulch-Piceance Basin development property (the "2012 Divestiture"). The Company received $325.3 million in cash proceeds and recognized a $4.5 million pre-tax loss included in other operating revenues for the year ended December 31, 2012. Due to final post-closing adjustments, the Company recognized an additional $3.1 million pre-tax loss included in other operating revenues for the year ended December 31, 2013.

Assets Held for Sale. The Company began marketing its remaining Powder River Basin assets, including 19,492 net mineral acres, during 2014. Therefore, the related assets and liabilities were classified as held for sale in the Consolidated Balance Sheet as of December 31, 2014. Upon the classification as held for sale, the assets were analyzed relative to their fair market values. The Company recognized proved and unproved property impairment of $14.8 million and $6.4 million, respectively, during the year ended December 31, 2014.

5. Long-Term Debt

The Company's outstanding debt is summarized below:

		As of December 31, 2014			As of December 31, 2013		
	Maturity Date	Principal	Unamortized Discount	Carrying Amount	Principal	Unamortized Discount	Carrying Amount
			(in thousands)				
Amended Credit Facility (1)	October 31, 2016	$ —	$—	$ —	$115,000	$—	$115,000
Convertible Notes (2)	March 15, 2028 (3)	25,344	—	25,344	25,344	—	25,344
7.625% Senior Notes (4)	October 1, 2019	400,000	—	400,000	400,000	—	400,000
7.0% Senior Notes (5)	October 15, 2022	400,000	—	400,000	400,000	—	400,000
Lease Financing Obligation (6)	August 10, 2020	3,648	—	3,648	43,329	—	43,329
Total Debt		$828,992	$—	$828,992	$983,673	$—	$983,673
Less: Current Portion of Long-Term Debt (7)(8)		25,770	—	25,770	4,591	—	4,591
Total Long-Term Debt		$803,222	$—	$803,222	$979,082	$—	$979,082

(1) The recorded value of the Amended Credit Facility approximates its fair value due to its floating rate structure.
(2) The aggregate estimated fair value of the Convertible Notes was approximately $25.1 million as of December 31, 2014 and 2013, based on reported market trades of these instruments.
(3) The Company has the right at any time, with at least 30 days' notice, to call the Convertible Notes, and the holders have the right to require the Company to purchase the notes on each of March 20, 2015, March 20, 2018 and March 20, 2023.
(4) The aggregate estimated fair value of the 7.625% Senior Notes was approximately $359.8 million and $430.2 million as of December 31, 2014 and 2013, respectively, based on reported market trades of these instruments.
(5) The aggregate estimated fair value of the 7.0% Senior Notes was approximately $366.0 million and $417.0 million as of December 31, 2014 and 2013, respectively, based on reported market trades of these instruments.
(6) The aggregate estimated fair value of the Lease Financing Obligation was approximately $3.5 million and $41.7 million as of December 31, 2014 and 2013, respectively. The decrease in estimated fair value is primarily related to the sale of equipment in the Piceance Divestiture. As there is no active public market for the Lease Financing Obligation, the aggregate estimated fair value was based on market-based parameters of comparable term secured financing instruments.

(7) The current portion of long-term debt as of December 31, 2014 includes the current portion of the Lease Financing Obligation and the principal amount of the Convertible Notes. The Company classified the Convertible Notes as a current obligation as of December 31, 2014 as the holders may require us to purchase their Convertible Notes for cash on March 20, 2015.
(8) The current portion of long-term debt as of December 31, 2013 includes the current portion of the Lease Financing Obligation.

Amended Credit Facility

The Company's Amended Credit Facility has a maturity date of October 31, 2016 and current commitments and borrowing base of $375.0 million. As of December 31, 2014, the Company had no amounts outstanding under the Amended Credit Facility. As credit support for future payment under a contractual obligation, a $26.0 million letter of credit has been issued under the Amended Credit Facility, which reduced the current available borrowing capacity of the Amended Credit Facility as of December 31, 2014 to $349.0 million.

Interest rates are LIBOR plus applicable margins of 1.5% to 2.5% or ABR plus 0.5% to 1.5% and the commitment fee is between 0.375% to 0.5% based on borrowing base utilization. The average annual interest rates incurred on the Amended Credit Facility were 1.9% and 2.0% for the years ended December 31, 2014 and 2013, respectively.

The borrowing base is required to be re-determined twice per year. On September 30, 2014, the borrowing base was reduced to $375.0 million based on June 30, 2014 reserves as adjusted for the Piceance and Powder River Oil Divestitures and the Company's hedge position. Future semi-annual borrowing bases will be computed based on proved oil, natural gas and NGL reserves, hedge positions and estimated future cash flows from those reserves, as well as any other outstanding debt of the Company.

The Amended Credit Facility also contains certain financial covenants. The Company is currently in compliance with all financial covenants and has complied with all financial covenants since issuance.

5% Convertible Senior Notes Due 2028

On March 12, 2008, the Company issued $172.5 million aggregate principal amount of Convertible Notes. On March 20, 2012, $147.2 million of the outstanding principal amount, or approximately 85% of the outstanding Convertible Notes, were put to the Company and redeemed by the Company at par. The Company settled the notes in cash. After the redemption, $25.3 million aggregate principal amount of the Convertible Notes was outstanding. The Convertible Notes mature on March 15, 2028, unless earlier converted, redeemed or purchased by the Company. The Convertible Notes are senior unsecured obligations and rank equal in right of payment to all of the Company's existing and future senior unsecured indebtedness, are senior in right of payment to all of the Company's future subordinated indebtedness, and are effectively subordinated to all of the Company's secured indebtedness with respect to the collateral securing such indebtedness. The Convertible Notes are structurally subordinated to all present and future secured and unsecured debt and other obligations of the Company's subsidiaries. The Convertible Notes are fully and unconditionally guaranteed by the subsidiaries that guarantee the Company's indebtedness under the Amended Credit Facility, the 7.625% Senior Notes and the 7.0% Senior Notes.

The Convertible Notes bear interest at a rate of 5% per annum, payable semi-annually in arrears on March 15 and September 15 of each year. Holders of the remaining Convertible Notes may require the Company to purchase all or a portion of their Convertible Notes for cash on each of March 20, 2015, March 20, 2018 and March 20, 2023 at a purchase price equal to 100% of the principal amount of the Convertible Notes to be repurchased, plus accrued and unpaid interest, if any, up to but excluding the applicable purchase date. The Company has the right, with at least 30 days' notice, to call the Convertible Notes. The Company classified the Convertible Notes as a current obligation on the Consolidated Balance Sheets as of December 31, 2014 as the holders may require us to purchase their Convertible Notes for cash on March 20, 2015.

7.625% Senior Notes Due 2019

On September 27, 2011, the Company issued $400.0 million in principal amount of 7.625% Senior Notes due 2019 at par. The 7.625% Senior Notes mature on October 1, 2019. Interest is payable in arrears semi-annually on April 1 and October 1 beginning April 1, 2012. The 7.625% Senior Notes are senior unsecured obligations of the Company and rank equal in right of payment with all of the Company's other existing and future senior unsecured indebtedness, including the Company's Convertible Notes and 7.0% Senior Notes. The 7.625% Senior Notes are redeemable at the Company's option at a redemption price of 103.813% of the principal amount of the notes on October 1, 2015. The 7.625% Senior Notes are fully and unconditionally guaranteed by the subsidiaries that guarantee the Company's indebtedness under the Amended Credit Facility, the Convertible Notes and the 7.0% Senior Notes. The 7.625% Senior Notes include certain covenants that limit the Company's ability to incur additional indebtedness, make restricted payments, create liens or sell assets and that prohibit the Company from paying dividends. The Company is currently in compliance with all financial covenants and has complied with all financial covenants since issuance.

7.0% Senior Notes Due 2022

On March 12, 2012, the Company issued $400.0 million in aggregate principal amount of 7.0% Senior Notes due 2022 at par. The 7.0% Senior Notes mature on October 15, 2022. Interest is payable in arrears semi-annually on April 15 and October 15 of each year. The 7.0% Senior Notes are senior unsecured obligations and rank equal in right of payment with all of the Company's other existing and future senior unsecured indebtedness, including the Company's Convertible Notes and 7.625% Senior Notes. The 7.0% Senior Notes are redeemable at the Company's option on October 15, 2017 at a redemption price of 103.5% of the principal amount of the notes. The 7.0% Senior Notes are fully and unconditionally guaranteed by the subsidiaries that guarantee the Company's indebtedness under the Amended Credit Facility, the Convertible Notes and the 7.625% Senior Notes. The 7.0% Senior Notes include certain covenants that limit the Company's ability to incur additional indebtedness, make restricted payments, create liens or sell assets and that prohibit the Company from paying dividends. The Company is currently in compliance with all financial covenants and has complied with all financial covenants since issuance.

Lease Financing Obligation Due 2020

On July 23, 2012, the Company entered into the Lease Financing Obligation, whereby the Company received $100.8 million through the sale and subsequent leaseback of existing compressors and related facilities owned by the Company. The Lease Financing Obligation expires on August 10, 2020, and the Company has the option to purchase the equipment at the end of the lease term for the then current fair market value. The Lease Financing Obligation also contains an early buyout option where the Company may purchase the equipment on February 10, 2019. The lease payments related to the equipment are recognized as principal and interest expense based on a weighted average implicit interest rate of 3.3%. See Note 13 for discussion of aggregate minimum future lease payments. As the result of the disposition of equipment in the West Tavaputs Divestiture and the Piceance Divestiture, the Company's remaining Lease Financing Obligation has been reduced to $3.6 million as of December 31, 2014 and the early buyout option is reduced to $1.8 million.

The following table summarizes, for the periods indicated, the cash or accrued portion of interest expense related to the Amended Credit Facility, 9.875% Senior Notes that were redeemed in full on July 15, 2013, Convertible Notes, 7.625% Senior Notes, 7.0% Senior Notes and the Lease Financing Obligation along with the non-cash portion resulting from the amortization of the debt discount and transaction costs through interest expense:

	As of December 31,		
	2014	2013	2012
	(in thousands)		
Amended Credit Facility (1)			
Cash interest	$ 4,837	$ 6,802	$ 5,652
Non-cash interest	2,342	2,342	2,342
9.875% Senior Notes (2)			
Cash interest	$ —	$13,373	$24,688
Non-cash interest	—	1,361	2,571
Convertible Notes (3)			
Cash interest	$ 1,264	$ 1,267	$ 2,909
Non-cash interest	5	6	1,771
7.625% Senior Notes (4)			
Cash interest	$30,500	$30,500	$30,500
Non-cash interest	1,090	1,070	1,066
7.0% Senior Notes (5)			
Cash interest	$28,000	$28,000	$22,400
Non-cash interest	814	795	659
Lease Financing Obligation (6)			
Cash interest	$ 638	$ 2,852	$ 1,353
Non-cash interest	12	30	15

(1) Cash interest includes amounts related to interest and commitment fees paid on the Amended Credit Facility and participation and fronting fees paid on the letter of credit.
(2) The stated interest rate for the 9.875% Senior Notes was 9.875% per annum with an effective interest rate of 11.2% per annum. The Company redeemed the 9.875% Senior Notes in full on July 15, 2013.
(3) The stated interest rate for the Convertible Notes is 5% per annum. The effective interest rate of the Convertible Notes includes amortization of the debt discount, which represented the fair value of the equity conversion feature at the time of issue. The stated interest rate of 5% on the Convertible Notes is the effective interest rate of the $25.3 million remaining principal balance, as the related debt discount was fully amortized as of March 31, 2012.
(4) The stated interest rate for the 7.625% Senior Notes is 7.625% per annum with an effective interest rate of 8.0% per annum.
(5) The stated interest rate for the 7.0% Senior Notes is 7.0% per annum with an effective interest rate of 7.2% per annum.
(6) The effective interest rate for the Lease Financing Obligation is 3.3% per annum. The decrease in cash interest from $2.9 million to $0.6 million for the years ended December 31, 2013 and 2014, respectively, is due to the West Tavaputs and Piceance Divestitures.

6. Asset Retirement Obligations

A reconciliation of the Company's asset retirement obligations for the year ended December 31, 2014, 2013 and 2012 is as follows:

	Year Ended December 31,		
	2014	2013	2012
		(in thousands)	
Beginning of period	$ 43,005	$ 47,616	$ 69,302
Liabilities incurred	4,027	2,359	4,046
Liabilities settled	(6,283)	(1,096)	(871)
Disposition of properties	(23,722)	(13,543)	(33,560)
Accretion expense	2,587	3,481	4,421
Revisions to estimate	3,238	4,188	4,278
End of period	$ 22,852	$ 43,005	$ 47,616
Less: Liabilities associated with properties held for sale	146	—	—
Less: Current asset retirement obligations	1,114	3,805	1,566
Long-term asset retirement obligations	$ 21,592	$ 39,200	$ 46,050

7. Fair Value Measurements

Assets and Liabilities Measured on a Recurring Basis

The Company's financial instruments, including cash and cash equivalents, accounts and notes receivable and accounts payable are carried at cost, which approximates fair value due to the short-term maturity of these instruments. The recorded value of the Amended Credit Facility, as discussed in Note 5, approximates its fair value due to its floating rate structure based on the LIBOR spread and the Company's borrowing base utilization.

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). The Company utilizes a mid-market pricing convention (the mid-point price between bid and ask prices) for valuation as a practical expedient for assigning fair value. The Company uses market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk. These inputs can be readily observable, market corroborated or generally unobservable. The Company primarily applies the market and income approaches for recurring fair value measurements and utilizes the best available information. Given the Company's historical market transactions, its markets and instruments are fairly liquid. Therefore, the Company has been able to classify fair value balances based on the observability of those inputs. A fair value hierarchy was established that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurements) and the lowest priority to unobservable inputs (Level 3 measurements).

Level 1—Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Level 1 primarily consists of financial instruments such as exchange-traded derivatives, listed securities and U.S. government treasury securities.

Level 2—Pricing inputs are other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace. Instruments in this category include non-exchange-traded derivatives such as over-the-counter forwards and options.

Level 3—Pricing inputs include significant inputs that are generally less observable than objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value. At each balance sheet date, the Company performs an analysis of all applicable instruments and includes in Level 3 all of those whose fair value is based on significant unobservable inputs.

The following tables set forth by level within the fair value hierarchy the Company's financial assets and financial liabilities that were measured at fair value on a recurring basis. Assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of assets and liabilities and their placement within the fair value hierarchy levels.

	As of December 31, 2014			
	Level 1	Level 2	Level 3	Total
	(in thousands)			
Assets				
Deferred Compensation Plan	$ 1,069	$ —	$—	$ 1,069
Cash Equivalents—Money Market Funds	75,066	—	—	75,066
Commodity Derivatives	—	195,176	—	195,176
Liabilities				
Commodity Derivatives	$ —	$ 200	$—	$ 200

	As of December 31, 2013			
	Level 1	Level 2	Level 3	Total
	(in thousands)			
Assets				
Deferred Compensation Plan	$ 941	$ —	$—	$ 941
Cash Equivalents—Money Market Funds	53	—	—	53
Commodity Derivatives	—	11,483	—	11,483
Liabilities				
Commodity Derivatives	$ —	$ 14,771	$—	$ 14,771

All fair values reflected in the table above and on the Consolidated Balance Sheets have been adjusted for non-performance risk. For applicable financial assets carried at fair value, the credit standing of the counterparties is analyzed and factored into the fair value measurement of those assets. In addition, the fair value measurement of a liability has been adjusted to reflect the nonperformance risk of the Company. The following methods and assumptions were used to estimate the fair values of the assets and liabilities in the table above.

Level 1 Fair Value Measurements—The Company maintains a non-qualified deferred compensation plan (as discussed in more detail in Note 11) which allows certain management employees to defer receipt of a portion of their compensation. The Company maintains assets for the deferred compensation plan in a rabbi trust. The assets of the rabbi trust are invested in publicly traded mutual funds and are recorded in prepayments and other current assets and deferred financing costs and other noncurrent assets on the Consolidated Balance Sheets. The Company also has highly liquid short term investments in money market funds. The deferred compensation plan financial assets are reported at fair value based on active market quotes, which represent Level 1 inputs. The money market fund investments are recorded at carrying value, which approximates fair value, and represents Level 1 inputs. The fair values of the Company's fixed rate $400.0 million principal 7.625% Senior Notes and $400.0 million principal 7.0% Senior Notes totaled $725.8 million and $847.2 million as of December 31, 2014 and 2013, respectively. The fair values of the Company's fixed rate Senior Notes are based on active market quotes, which represent Level 1 inputs.

Level 2 Fair Value Measurements—The fair value of oil, natural gas and NGL swaps and forwards are estimated using a combined income and market valuation methodology with a mid-market pricing convention based upon forward commodity price and volatility curves. The curves are obtained from independent pricing services reflecting broker market quotes. The Company did not make any adjustments to the obtained curves. The pricing services publish observable market information from multiple brokers and exchanges. No proprietary models are used by the pricing services for the inputs. The Company utilized the counterparties' valuations to assess the reasonableness of the Company's valuations.

There is no active, public market for the Company's Amended Credit Facility, Convertible Notes or Lease Financing Obligation. The Amended Credit Facility balance of zero and $115.0 million as of December 31, 2014 and 2013, respectively, approximates its fair value due to its floating rate structure. The Convertible Notes fair value of $25.1 million as of December 31, 2014 and 2013 is measured based on market-based parameters of the various components of the Convertible Notes and over the counter trades. The Lease Financing Obligation fair values of $3.5 million and $41.7 million as of December 31, 2014 and 2013, respectively, are measured based on market-based parameters of comparable term secured financing instruments. The fair value measurements for the Amended Credit Facility, Convertible Notes and Lease Financing Obligation represent Level 2 inputs.

Level 3 Fair Value Measurements—As of December 31, 2014 and 2013, the Company did not have assets or liabilities that were measured on a recurring basis classified under a Level 3 fair value hierarchy.

Assets and Liabilities Measured on a Non-recurring Basis

The Company utilizes fair value on a non-recurring basis to perform impairment tests on its property and equipment when required. During the year ended December 31, 2014, the Company recognized impairment on proved and unproved property of $39.8 million. Included in the total impairment charge of $39.8 million was $21.1 million of impairment charges related to the remaining Powder River Basin assets for which the Company utilized third party purchase offers as the basis for determining fair value. This property was classified as held for sale as of December 31, 2014. The inputs used to determine such fair value for other non-recurring impairment tests are primarily based upon internally developed cash flow models as well as available external market data and would generally be classified within Level 3.

	Net Carrying Value as of December 31, 2014	Impairment for the Year Ended December 31, 2014		
		Level 1	Level 2	Level 3
		(in thousands)		
Proved property [1][2]	$1,588,038	$—	$—	$15,761
Unproved property [1][2]	151,368	—	—	24,082

(1) See Note 2 for additional details on impairment expense recognized.

(2) Includes $6.7 million of net proved property and $2.5 million of net unproved property associated with properties held for sale as of December 31, 2014.

The Company utilizes fair value on a non-recurring basis to perform impairment tests on its property and equipment when required. During the year ended December 31, 2013, the Company recorded impairment charges of $226.6 million on proved and unproved oil and gas properties. Included in the total impairment charge of $226.6 million was $209.5 million of impairment charges related to the West Tavaputs area of the Uinta Basin for which the Company utilized third party purchase offers as the basis for determining fair value. This property was sold in December 2013. The inputs used to determine such fair value for other non-recurring impairment tests are primarily based upon internally developed cash flow models as well as available external market data and would generally be classified within Level 3.

		Impairment for the Year Ended December 31, 2013		
	Net Carrying Value as of December 31, 2013	Level 1	Level 2	Level 3
		(in thousands)		
Proved property [1]	$1,937,913	$—	$—	$206,953
Unproved property [1]	246,270	—	—	19,598

(1) See Note 2 for additional details on impairment expense recognized.

8. Derivative Instruments

The Company uses financial derivative instruments as part of its price risk management program to achieve a more predictable cash flow from its production revenues by reducing its exposure to commodity price fluctuations. The Company has entered into financial commodity swap contracts related to the sale of a portion of the Company's production. The Company does not enter into derivative instruments for speculative or trading purposes.

In addition to financial contracts, the Company at times may be party to various physical commodity contracts for the sale of oil, natural gas and NGLs that have varying terms and pricing provisions. These physical commodity contracts qualify for the normal purchase and normal sale exception and, therefore, are not subject to hedge or mark-to-market accounting. The financial impact of physical commodity contracts is included in oil, natural gas and NGL production revenues at the time of settlement.

All derivative instruments, other than those that meet the normal purchase and normal sale exception, as mentioned above, are recorded at fair value and included on the Consolidated Balance Sheets as assets or liabilities. The following table summarizes the location, as well as the gross and net fair value amounts of all derivative instruments presented on the Consolidated Balance Sheets as of the dates indicated.

	As of December 31, 2014		
Balance Sheet	**Gross Amounts of Recognized Assets**	**Gross Amounts Offset in the Balance Sheet**	**Net Amounts of Assets Presented in the Balance Sheet**
		(in thousands)	
Derivative assets (current)	$145,426	$ (200)(1)	$145,226
Derivative assets (noncurrent)	49,750	—(1)	49,750
Total derivative assets	$195,176	$ (200)	$194,976
	Gross Amounts of Recognized Liabilities	**Gross Amounts Offset in the Balance Sheet**	**Net Amounts of Liabilities Presented in the Balance Sheet**
		(in thousands)	
Derivative liabilities	$ (200)	$ 200(2)	$ —
Derivatives and other noncurrent liabilities	—	—(2)	—(3)
Total derivative liabilities	$ (200)	$ 200	$ —

	As of December 31, 2013		
Balance Sheet	**Gross Amounts of Recognized Assets**	**Gross Amounts Offset in the Balance Sheet**	**Net Amounts of Assets Presented in the Balance Sheet**
		(in thousands)	
Derivative assets (current)	$ 8,259	$(8,086)(1)	$ 173
Derivative assets (noncurrent)	3,224	(685)(1)	2,539
Total derivative assets	$ 11,483	$(8,771)	$ 2,712
	Gross Amounts of Recognized Liabilities	**Gross Amounts Offset in the Balance Sheet**	**Net Amounts of Liabilities Presented in the Balance Sheet**
		(in thousands)	
Derivative liabilities	$ (14,074)	$ 8,086(2)	$ (5,988)
Derivatives and other noncurrent liabilities	(697)	685(2)	(12)(3)
Total derivative liabilities	$ (14,771)	$ 8,771	$ (6,000)

(1) Amounts are netted against derivative asset balances with the same counterparty, and therefore, are presented as a net asset on the Consolidated Balance Sheets.
(2) Amounts are netted against derivative liability balances with the same counterparty, and therefore are presented as a net liability on the Consolidated Balance Sheets.
(3) As of December 31, 2014 and 2013, this line item on the Consolidated Balance Sheets includes $3.0 million and $3.5 million of other noncurrent liabilities, respectively.

Effective January 1, 2012, the Company elected to discontinue hedge accounting prospectively. As a result, the mark-to-market value of all commodity hedge instruments within AOCI at December 31, 2011 was frozen in AOCI as of the de-designation date and was reclassified into earnings in future periods as the original hedged transactions occurred. All cash flow hedged transactions were completed by December 31, 2014. The following table summarizes the cash flow hedge gains, net of tax, and their locations on the Consolidated Balance Sheets and Consolidated Statements of Operations for the periods indicated:

	Derivatives Qualifying as Cash Flow Hedges	Year Ended December 31, 2014	2013	2012
		(in thousands)		
Amount of Gain (Loss) Recognized in AOCI (1)	Commodity Hedges	$—	$ —	$ —
Amount of Gain (Loss) Reclassified from AOCI into Income (net of tax) (1)(2)	Commodity Hedges	$669	$4,663	$50,712
Amount of Gain (Loss) Recognized in Income on Ineffective Hedges	Commodity Hedges	$—	$ —	$ —

(1) Presented net of income tax expense of $0.4 million, $2.8 million and $30.5 million for the years ended December 31, 2014, 2013 and 2012, respectively.
(2) Gains reclassified from AOCI into income are included in the oil, gas and NGL production revenues in the Consolidated Statements of Operations.

As of December 31, 2014, the Company had financial instruments in place to hedge the following volumes for the periods indicated:

	Year Ending December 31, 2015	2016	2017
Oil (Bbls)	4,022,600	1,737,000	365,000
Natural Gas (MMbtu)	7,207,000	1,830,000	—

The table below summarizes the commodity derivative gains and losses the Company recognized related to its oil, gas and NGL derivative instruments for the periods indicated:

	Year Ended December 31, 2014	2013	2012
		(in thousands)	
Commodity derivative settlements on derivatives designated as cash flow hedges (1)	$ 1,070	$ 7,463	$81,166
Total commodity derivative gain (loss) (2)	197,447	(23,068)	72,759

(1) Included in oil, gas and NGL production revenues in the Consolidated Statements of Operations.
(2) Included in commodity derivative gain (loss) in the Consolidated Statements of Operations.

The Company's derivative financial instruments are generally executed with major financial or commodities trading institutions that expose the Company to market and credit risks and may, at times, be concentrated with certain counterparties or groups of counterparties. The Company had hedges in place with eight different counterparties as of December 31, 2014. Although notional amounts are used to express the volume of these contracts, the amounts potentially subject to credit risk, in the event of non-performance by the counterparties, are substantially smaller. The creditworthiness of counterparties is subject to continual review by management, and the Company believes all of these institutions currently are acceptable credit risks. Full performance is anticipated, and the Company has no past due receivables from any of its counterparties.

It is the Company's policy to enter into derivative contracts with counterparties that are lenders in the Amended Credit Facility, affiliates of lenders in the Amended Credit Facility or potential lenders in the Amended Credit Facility. The Company's derivative contracts are documented using an industry standard contract known as a Schedule to the Master Agreement and International Swaps and Derivative Association, Inc. ("ISDA") Master Agreement or other contracts. Typical terms for these contracts include credit support requirements, cross default provisions, termination events and set-off provisions. The Company is not required to provide any credit support to its counterparties other than cross collateralization with the properties securing the Amended Credit Facility. The Company has set-off provisions in its derivative contracts with lenders under its Amended Credit Facility which, in the event of a counterparty default, allow the Company to set-off amounts owed to the defaulting counterparty under the Amended Credit Facility or other obligations against monies owed the Company under derivative contracts. Where the counterparty is not a lender under the Company's Amended Credit Facility, it may not be able to set-off amounts owed by the Company under the Amended Credit Facility, even if such counterparty is an affiliate of a lender under such facility. The Company does not have any derivative balances that are offset by cash collateral.

9. Income Taxes

The expense for income taxes consisted of the following for the periods indicated:

	Year Ended December 31,		
	2014	2013	2012
		(in thousands)	
Current:			
Federal	$ 1,220	$ (1,233)	$ 966
State	44	(352)	886
Foreign	1	2	1
Deferred:			
Federal	10,246	(107,300)	100
State	6,398	(9,750)	(317)
Total	$17,909	$(118,633)	$1,636

Income tax expense differed from the amounts computed by applying the U.S. federal income tax rate of 35% to pretax income from continuing operations as a result of the following:

	Year Ended December 31,		
	2014	2013	2012
		(in thousands)	
Income tax expense at the federal statutory rate	$11,546	$(108,978)	$ 777
State income taxes, net of federal tax effect	932	(6,702)	(269)
Incentive stock compensation	199	678	635
Nondeductible political contributions and lobbying costs	108	96	271
Nondeductible officer compensation	229	138	—
Other permanent items	89	52	26
Deferred tax related to the changes in overall state tax rates	5,230	(3,851)	310
Other, net	(424)	(66)	(114)
Income tax expense (benefit)	$17,909	$(118,633)	$1,636

The tax effects of temporary differences that give rise to significant components of the deferred tax assets and deferred tax liabilities at December 31, 2014 and 2013 are presented below:

	As of December 31,	
	2014	2013
	(in thousands)	
Current:		
Deferred tax assets (liabilities):		
Derivative instruments	$ (54,933)	$ (89)
Accrued expenses	229	400
Bad debt expense	5	8
Prepaid expenses	(702)	(648)
Other	(17)	130
Total current deferred tax assets (liabilities)	$ (55,418)	$ (199)
Long-term:		
Deferred tax assets:		
Net operating loss carryforward	$ 56,529	$ 75,511
Deferred offering costs	1,182	1,243
Stock-based compensation	15,767	14,200
Deferred rent	787	962
Minimum tax credit carryforward	1,690	688
Deferred compensation	1,062	999
State tax credit carryforwards	5,110	5,871
Production payment loan	—	3,839
Financing obligation	1,586	16,227
Other	250	222
Less: Valuation allowance	(5,110)	(5,871)
Total long-term deferred tax assets	78,853	113,891
Deferred tax liabilities:		
Oil and gas properties	(182,385)	(276,523)
Long-term derivative instruments	(18,818)	1,306
Total long-term deferred tax liabilities	(201,203)	(275,217)
Net long-term deferred tax liabilities	$(122,350)	$(161,326)

At December 31, 2014, the Company had approximately $168.2 million of federal tax net operating loss carryforwards which expire beginning in 2027. The Company has a federal alternative minimum tax credit carryforward of $1.7 million, which has no expiration date.

In assessing the realizability of deferred tax assets, management must consider whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. Management considers all available evidence (both positive and negative) in determining whether a valuation allowance is required. Such evidence includes the scheduled reversal of deferred tax liabilities, projected future taxable income and tax planning strategies in making this assessment, and judgment is required in considering the relative weight of negative and positive evidence. The Company continues to monitor facts and circumstances in the reassessment of the likelihood that operating loss carryforwards, credits and other deferred tax assets will be utilized prior to their expiration. As a result, it may be determined that a deferred tax asset valuation allowance should be established. Any increases or decreases in a deferred tax asset valuation allowance would impact net income through offsetting changes in income tax expense. At December 31, 2014, the Company had approximately $7.9 million of state income tax credit carryforwards that begin expiring in 2018. A valuation allowance against these credits was recorded in 2011. It is currently estimated that the state income tax credits will not be utilized because the Company does not project to have sufficient future taxable income in the appropriate jurisdictions, and therefore the valuation allowance on the full amount of the credit carryforwards will remain.

At December 31, 2014 and 2013, the Consolidated Balance Sheet reflected a net deferred tax liability of $177.8 million and $161.5 million, respectively.

The Company accounts for uncertainty in income taxes for tax positions taken or expected to be taken in a tax return. The Company recognizes the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained upon examination by the taxing authorities, based on the technical merits. The Company did not have any additions, reductions or settlements of unrecognized tax benefits in the years ended December 2014, 2013 and 2012. In 2014, the Company generated no uncertain tax positions.

The Company's policy is to classify accrued penalties and interest related to unrecognized tax benefits in the Company's income tax provision. As of December 31, 2014, the Company did not have any accrued interest or penalties associated with any unrecognized tax benefits, nor was any interest expense recognized during the current year.

The Company and its subsidiaries file income tax returns in the U.S. federal jurisdiction and in various states. With few exceptions, the Company is subject to U.S. federal tax examination for years 2011 through 2014 and is subject to state tax examination for years 2010 through 2014.

10. Stockholders' Equity

Common and Preferred Stock. The Company's authorized capital structure consists of 75,000,000 shares of preferred stock, par value $0.001 per share and 150,000,000 shares of common stock, par value $0.001 per share. In October 2004, 150,000 shares of $0.001 per share par value preferred stock were designated as Series A Junior Participating Preferred Stock, none of which are outstanding. The remainder of the authorized preferred stock is undesignated. There are no issued and outstanding shares of preferred stock.

When issued, each share of Series A Junior Participating Preferred Stock will entitle the holder thereof to 1,000 votes on all matters submitted to a vote of the Company's stockholders.

Treasury Stock. The Company may occasionally acquire treasury stock, which is recorded at cost, in connection with the vesting and exercise of stock-based awards or for other reasons. As of December 31, 2014, all treasury stock held by the Company was retired.

The following table reflects the activity in the Company's common and treasury stock for the periods indicated:

	Year Ended December 31,		
	2014	2013	2012
Common Stock Outstanding:			
Shares at beginning of period	49,152,448	48,150,475	47,809,903
Exercise of common stock options	7,926	259,699	36,560
Shares issued for 401(k) plan	36,533	47,235	41,415
Shares issued for directors' fees	44,551	52,081	12,973
Shares issued for nonvested equity shares of common stock	857,870	1,081,259	454,666
Shares retired or forfeited	(572,691)	(438,301)	(205,042)
Shares at end of period	49,526,637	49,152,448	48,150,475
Treasury Stock:			
Shares at beginning of period	—	—	—
Treasury stock acquired	116,813	96,880	92,393
Treasury stock retired	(116,813)	(96,880)	(92,393)
Shares at end of period	—	—	—

Accumulated Other Comprehensive Income. The components of accumulated other comprehensive income and related tax effects for the years ended December 31, 2012, 2013 and 2014 were as follows:

	Gross	Tax Effect	Net of Tax
		(in thousands)	
Accumulated other comprehensive income—December 31, 2011	$ 89,714	$(33,670)	$ 56,044
Reclassification adjustment for realized gains on hedges included in net income	(81,170)	30,458	(50,712)
Accumulated other comprehensive income—December 31, 2012	$ 8,544	$ (3,212)	$ 5,332
Reclassification adjustment for realized gains on hedges included in net income	(7,465)	2,802	(4,663)
Accumulated other comprehensive income—December 31, 2013	$ 1,079	$ (410)	$ 669
Reclassification adjustment for realized gains on hedges included in net income	(1,079)	410	(669)
Accumulated other comprehensive income—December 31, 2014	$ —	$ —	$ —

11. Equity Incentive Compensation Plans and Other Employee Benefits

The Company maintains various stock-based compensation plans and other employee benefit plans as discussed below. Stock-based compensation is measured at the grant date based on the value of the awards, and the fair value is recognized on a straight-line basis over the requisite service period (usually the vesting period).

The following table presents the non-cash stock-based compensation related to equity awards for the periods indicated:

	Year Ended December 31,		
	2014	2013	2012
	(in thousands)		
Common stock options	$ 2,073	$ 4,696	$ 7,189
Nonvested equity common stock	6,845	7,492	7,394
Nonvested equity common stock units (1)	1,065	1,272	708
Nonvested performance-based equity	990	2,174	1,079
Total	$10,973	$15,634	$16,370

(1) Includes non-cash stock-based compensation related to director fees of $0.1 million, $0.4 million and $0.2 million for the years ended December 31, 2014, 2013 and 2012, respectively.

Unrecognized compensation cost as of December 31, 2014 was $15.7 million related to grants of nonvested stock options and nonvested equity shares of common stock that are expected to be recognized over a weighted-average period of 2.3 years.

Stock Options and Nonvested Equity Shares. In May 2012, the Company's stockholders approved and the Company adopted its 2012 Equity Incentive Plan (the "2012 Incentive Plan"). The purpose of the 2012 Incentive Plan is to enhance the Company's ability to attract and retain officers, employees and directors and to provide such persons with an interest in the Company aligned with the interests of stockholders. The 2012 Incentive Plan provides for the grant of stock options (including incentive stock options and non-qualified stock options) and other awards, including performance units, performance shares, share awards, share units, restricted stock, cash incentive, and stock appreciation rights or SARs.

The aggregate number of shares that the Company may issue under the 2012 Incentive Plan may not exceed 2,051,402 shares, subject to adjustment for future stock splits, stock dividends and similar changes in the Company's capitalization. Shares underlying grants that expire without being exercised or are forfeited are available for grant under the 2012 Incentive Plan. The aggregate number of shares of common stock subject to options, stock appreciation rights, or performance-based awards granted to a participant during any calendar year may not exceed 500,000 shares. The 2012 Incentive Plan provides that all awards granted under the 2012 Incentive Plan expire not more than 10 years from the grant date and have an exercise price of no less than the closing price of the Company's common stock on the date of grant.

Currently, the Company's practice is to issue new shares upon stock option exercise. The Company does not expect to repurchase any shares in the open market or issue treasury shares to settle any such exercises. For the years ended December 31, 2014, 2013 and 2012, the Company did not pay cash to repurchase any stock option exercises.

The fair value of each share-based option award under all of the Company's plans is estimated on the date of grant using a Black-Scholes pricing model that incorporates the assumptions noted in the following table. Estimated expected volatilities were based upon historical volatility of the Company's common stock. The Company does not expect to declare or pay dividends in the foreseeable future; thus, the Company used a 0% expected dividend yield, which is comparable to most of its peers in the industry. The expected terms range from 0.09 years to 6.0 years, or a weighted average of 4.3 years to 4.6 years, based on 25% of each grant's vesting on each anniversary date and factoring in potential blackout dates, historic exercises and expectations of future employee behavior. The risk-free rate is based on the U.S. Treasury yield curve in effect on the date of grant and extrapolated to approximate the expected life of the award. The Company estimated a 4% to 10% annual compounded forfeiture rate for the year 2012 based on historical employee turnover and actual forfeitures. The Company did not grant any share-based option awards during the years 2014 or 2013.

	2012
Weighted average volatility	51%
Expected dividend yield	— %
Weighted average expected term (in years)	4.3
Weighted average risk-free rate	1.8%

A summary of share-based option activity under all the Company's plans as of December 31, 2014, and changes during the year then ended, is presented below:

	Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value
Outstanding at January 1, 2014	1,748,696	$32.66		
Granted	—	$ —		
Exercised	(7,926)	$18.22		
Forfeited or expired	(401,405)	$33.56		
Outstanding at December 31, 2014	1,339,365	$32.47	1.37	$—
Vested and expected to vest, at December 31, 2014 through the life of the options	1,332,062	$30.33	1.92	$—
Vested and exercisable at December 31, 2014	1,151,004	$33.05	1.60	$—

The per share weighted-average grant date fair value of options granted for the year ended December 31, 2012 was $11.02. The total intrinsic value of options exercised for the years ended December 31, 2014, 2013 and 2012 were $0.1 million, $0.5 million and $0.4 million, respectively. With respect to stock option exercises, the Company received $0.1 million, $6.4 million, and $0.7 million for the years ended December 31, 2014, 2013 and 2012, respectively.

A summary of the Company's nonvested equity shares of common stock as of December 31, 2014, 2013 and 2012, and changes during the years then ended, is presented below:

	Year Ended December 31,					
	2014		2013		2012	
	Shares	Weighted Average Grant Date Fair Value	Shares	Weighted Average Grant Date Fair Value	Shares	Weighted Average Grant Date Fair Value
Outstanding at January 1,	756,118	$22.17	579,188	$31.02	639,628	$35.12
Granted	542,209	$22.00	630,715	$17.98	274,679	$25.62
Vested	(292,168)	$24.05	(270,482)	$29.82	(241,736)	$34.61
Forfeited or expired	(213,095)	$21.99	(183,303)	$24.87	(93,383)	$33.39
Outstanding at December 31,	793,064	$21.47	756,118	$22.17	579,188	$31.02

Equity common stock units were issued beginning on July 1, 2012 and will be converted to shares of common stock as they vest. As of December 31, 2014, equity common stock units have only been issued for payment of director fees. A summary of the Company's nonvested equity share units of common stock as of December 31, 2014, 2013 and 2012, and changes during the years then ended, is presented in the table below:

	Year Ended December 31,					
	2014		2013		2012	
	Shares	Weighted Average Grant Date Fair Value	Shares	Weighted Average Grant Date Fair Value	Shares	Weighted Average Grant Date Fair Value
Outstanding at January 1,	55,778	$19.35	49,185	$18.50	—	$ —
Granted	45,928	$24.49	56,464	$22.33	58,983	$18.83
Vested	(46,761)	$22.25	(49,871)	$18.96	(9,798)	$20.51
Forfeited or expired	—	$ —	—	$ —	—	$ —
Outstanding at December 31,	54,945	$23.84	55,778	$19.35	49,185	$18.50

The fair value of equity awards vested for the years ended December 31, 2014, 2013 and 2012 was $8.0 million, $8.1 million and $8.6 million, respectively.

Performance Share Programs

2014 Program. In February 2014, the Compensation Committee of the Board of Directors of the Company approved a new performance share program (the "2014 Program") pursuant to the 2012 Equity Incentive Plan. The performance-based awards contingently vest in May 2017, depending on the level at which the performance goals are achieved. The performance goals, which will be measured over the three year period ending December 31, 2016, consist of the Company's total shareholder return ("TSR") ranking relative to a defined peer group's individual TSRs ("Relative TSR") (weighted at 60%) and the percentage change in discretionary cash flow per debt adjusted share relative to a defined peer group's percentage calculation ("DCF per Debt Adjusted Share") (weighted at 40%). The Relative TSR and DCF per Debt Adjusted Share goals will vest at 25% of the total award for performance met at the threshold level, 100% at the target level and 200% at the stretch level. If the actual results for a metric are between the threshold and target levels or between the target and stretch levels, the vested number of shares will be prorated based on the actual results compared to the threshold, target and stretch goals. If the threshold metrics are not met, no shares will vest. In any event, the total number of shares of common stock that could vest will not exceed 200% of the original number of performance shares granted. At the end of the three year vesting period, any shares that have not vested will be forfeited. A total of 315,661 shares were granted under this program during the year ended December 31, 2014. All compensation expense related to the TSR metric will be recognized if the requisite service period is fulfilled, even if the market condition is not achieved. All compensation expense related to the DCF per Debt Adjusted Share metric will be based upon the number of shares expected to vest at the end of the three year period.

2013 Program. In February 2013, the Compensation Committee approved a new performance share program (the "2013 Program") pursuant to the 2012 Equity Incentive Plan. The performance-based awards contingently vest in May 2016, depending on the level at which the performance goals are achieved. The performance goals, which will be measured over the three year period ending December 31, 2015, consist of the Company's Relative TSR (weighted at 33 1/3%), the percentage change in discretionary cash flow per debt adjusted share relative to a defined peer group's percentage calculation ("DCF per Debt Adjusted Share") (weighted at 33 1/3%) and percentage change in proved oil, natural gas and NGL reserves per debt adjusted share ("Reserves per Debt Adjusted Share") (weighted at 33 1/3%). The Relative TSR and DCF per Debt Adjusted Share goals will vest at 25% of the total award for performance met at the threshold level, 100% at the target level and 200% at the stretch level. The Reserves per Debt Adjusted Share goal will vest at 50% of the total award for performance met at the threshold level, 100% at the target level and 200% at the stretch level. If the actual results for a metric are between the threshold and target levels or between the target and stretch levels, the vested number of shares will be prorated based on the actual results compared to the threshold, target and stretch goals. If the threshold metrics are not met, no shares will vest. In any event, the total number of shares of common stock that could vest will not exceed 200% of the original number of performance shares granted. At the end of the three year vesting period, any shares that have not vested will be forfeited. A total of 450,544 shares were granted under this program during the year ended December 31, 2013. All compensation expense related to the Relative TSR metric will be recognized if the requisite service period is fulfilled, even if the market condition is not achieved. All compensation expense related to the DCF per Debt Adjusted Share metric and the Reserves per Debt Adjusted Share metric will be based upon the number of shares expected to vest at the end of the three year period.

2012 Program. In March 2012, the Compensation Committee approved a new performance share program (the "2012 Program"). The performance-based awards contingently vest in May 2015, depending on the level at which the performance goals are achieved. The performance goals, which will be measured over the three year period ending December 31, 2014, consist of the Company's TSR ranking relative to a defined peer group's individual TSR (weighted at 33 1/3%), the percentage change in DCF per Debt Adjusted Share relative to a defined peer group's percentage calculation (weighted at 33 1/3%) and the change in proved oil and natural gas reserves per debt adjusted share (weighted at 33 1/3%). Fifty percent of the total award will vest for performance met at the threshold level, 100% will vest at the target level and 200% will vest at the stretch level. If the actual results for a metric are between the threshold and target levels or between the target and stretch levels, the vested number of shares will be adjusted on a prorated basis of the actual results compared to the threshold, target and stretch goals. If the threshold metrics are not met, no shares will vest. In any event, the total number of shares of common stock that could vest will not exceed 200% of the original number of performance shares granted. At the end of the three year vesting period, any shares that have not vested will be forfeited. All compensation expense related to the TSR metric will be recognized if the requisite service period is fulfilled, even if the market condition is not achieved. All compensation expense related to the DCF per Debt Adjusted Share and oil and natural gas reserves per debt adjusted share metrics will be based upon the number of shares expected to vest at the end of the three year period. A total of 179,987 shares were granted under this program during the year ended December 31, 2012. Based upon the Company's performance through 2014, none of the 2012 Program performance shares will vest in May 2015.

2010 Program. In February 2010, the Compensation Committee approved a performance share program (the "2010 Program"). Upon commencement of the 2010 Program and during each subsequent year of the 2010 Program through 2013, the Compensation Committee met to approve target and stretch goals for certain operational or financial metrics that are selected by the Compensation Committee for the upcoming year and to determine whether metrics for the prior year have been met. As new goals are established each year for the performance-based awards, a new grant date and a new fair value are created for financial reporting purposes for those shares that could potentially vest in the upcoming year. Compensation expense is recognized based upon an estimate of the extent to which the performance goals would be met. If such goals are not met, no compensation expense is recognized and any previously recognized compensation expense is reversed.

The 2010 Program has both performance-based and market-based goals. All compensation expense related to the market-based goals will be recognized if the requisite service period is fulfilled, even if the market condition is not achieved. Based on Company performance in 2010, 2011, 2012 and 2013, 25.9%, 26.6%, 0.0% and 19.8%, respectively, of the 2010 Program performance-based shares vested in February 2011, February 2012, February 2013 and February 2014, respectively, for a total of 72.3% of the total performance-based shares vested over the four year vesting period. A total of 59,582, 57,944, zero and 21,968 shares vested in February 2011, February 2012, February 2013 and February 2014, respectively.

Based on the 2010 Program market-based goals, which were based on the Company's TSR ranking relative to a defined peer group's individual TSR, 37.5%, 12.5%, 0.0% and 33.4% vested in February 2011, 2012, 2013 and 2014, respectively, based on the Company's rankings as of December 31, 2010, 2011, 2012, and 2013, respectively, for a total of 83.4% of the total market-based shares vested over the four year vesting period. A total of 21,574, 6,801, zero and 9,242 shares vested in February 2011, February 2012, February 2013 and February 2014, respectively.

A summary of the Company's non-vested performance-based equity shares of common stock as of December 31, 2014, 2013 and 2012, and changes during the years then ended, is presented below:

	Year Ended December 31,					
	2014		2013		2012	
	Shares	Weighted Average Grant Date Fair Value	Shares	Weighted Average Grant Date Fair Value	Shares	Weighted Average Grant Date Fair Value
Outstanding at January 1,	584,032	$19.80	291,606	$26.85	195,630	$33.36
Vested	(42,833)	$19.51	—	$ —	(64,745)	$39.90
Modified, performance goals revised (1)	—	$ —	(108,933)	$27.75	(121,191)	$39.90
Modified, performance goals revised (1)	—	$ —	108,933	$18.18	121,191	$27.75
Granted	315,661	$23.86	450,544	$19.99	179,987	$27.57
Forfeited or expired	(242,783)	$22.13	(158,118)	$22.52	(19,266)	$33.82
Outstanding at December 31,	614,077	$19.62	584,032	$19.80	291,606	$26.85

(1) As the Compensation Committee approved new performance metrics for the vesting of performance shares in the upcoming year, a new grant date was then created for any unvested awards that were granted in previous years, and a new fair value was established for financial reporting purposes.

The fair value of the performance-based shares vested in the years ended December 31, 2014 and 2012 was $0.8 million and $2.6 million, respectively.

Director Fees. The Company's non-employee, or outside, directors, may elect to receive all or a portion of their annual retainer and meeting fees in the form of restricted stock units ("RSUs"), which are settled with shares of the Company's common stock, issued pursuant to the Company's 2012 Incentive Plan. After each quarter, RSUs with a value equal to the fees payable for that quarter, calculated using the closing price for the Company's common stock on the last trading day of the quarter, will be delivered to each outside director who elected before that quarter to receive RSUs for payment of director fees. These nonvested RSUs will vest immediately at the end of the applicable quarter. Once vested, the RSUs will settle at the end of the applicable quarter or such later date elected by the director.

A summary of the Company's directors' fees and equity-based compensation for the years ended December 31, 2014, 2013 and 2012 is presented below:

	Year Ended December 31,		
	2014	2013	2012
Director fees (shares)	3,928	16,151	12,973
Stock-based compensation (in thousands)	$ 75	$ 351	$ 276

Other Employee Benefits-401(k) Savings Plan. The Company has an employee-directed 401(k) savings plan (the "401(k) Plan") for all eligible employees over the age of 21. Under the 401(k) Plan, employees may make voluntary contributions based upon a percentage of their pretax income, subject to statutory limitations.

The Company matches 100% of each employee's contribution, up to 6% of the employee's pretax income, with 50% of the match made with the Company's common stock. The Company's cash and common stock contributions are fully vested upon the date of match, and employees can immediately sell the portion of the match made with the Company's common stock. The Company made matching cash and common stock contributions of $1.7 million, $1.9 million and $2.0 million for the years ended December 31, 2014, 2013 and 2012, respectively.

Deferred Compensation Plan. In 2010, the Company adopted a non-qualified deferred compensation plan for certain employees and officers whose eligibility to participate in the plan was determined by the Compensation Committee of the Company's Board of Directors. The Company makes matching cash contributions on behalf of eligible employees up to 6% of the employee's cash compensation once the contribution limits are reached on the Company's 401(k) Plan. All amounts deferred and matched under the plan vest immediately. Deferred compensation, including accumulated earnings on the participant-directed investment selections, is distributable in cash at participant-specified dates or upon retirement, death, disability, change in control or termination of employment.

The table below summarizes the activity in the plan during the years ended December 31, 2014 and 2013, and the Company's ending deferred compensation liability as of December 31, 2014 and 2013:

	Year Ended December 31,	
	2014	2013
	(in thousands)	
Beginning deferred compensation liability balance	$ 941	$ 966
Employee contributions	441	206
Company matching contributions	160	115
Distributions	(503)	(441)
Participant earnings (losses)	30	95
Ending deferred compensation liability balance	$1,069	$ 941
Amount to be paid within one year	$ 220	$ 451
Remaining balance to be paid beyond one year	$ 849	$ 490

The Company has established a rabbi trust to offset the deferred compensation liability and protect the interests of the plan participants. The investments in the rabbi trust seek to offset the change in the value of the related liability. As a result, there is no expected impact on earnings or earnings per share from the changes in market value of the investment assets because the changes in market value of the trust assets are offset by changes in the value of the deferred compensation plan liability. The gains and losses from changes in fair value of the investments are included in interest and other income in the Consolidated Statements of Operations.

The following table represents the Company's activity in the investment assets held in the rabbi trust during the years ended December 31, 2014 and 2013:

	Year Ended December 31,	
	2014	2013
	(in thousands)	
Beginning investment balance	$ 941	$ 966
Investment purchases	601	321
Distributions	(503)	(441)
Earnings (losses)	30	95
Ending investment balance	$1,069	$ 941

12. Significant Customers and Other Concentrations

Significant Customers. During 2014, two customers individually accounted for over 10% of the Company's oil, gas and NGL production revenues. During 2013, one customer individually accounted for over 10% of the Company's oil, gas and NGL production revenues. During 2012, two customers individually accounted for over 10% of the Company's oil, gas and NGL production revenues. Although diversified among many companies, collectability is dependent upon the financial stability of each individual company and is influenced by the general economic conditions of the industry. Management believes that the loss of any individual purchaser would not have a long-term material adverse impact on the financial position or results of operations of the Company.

Concentrations of Market Risk. The future results of the Company's oil and gas operations will be affected by the market prices of oil, natural gas and NGLs. A readily available market for oil, natural gas and NGLs in the future will depend on numerous factors beyond the control of the Company, including weather, imports, marketing of competitive fuels, proximity and capacity of oil and gas pipelines and other transportation facilities, any oversupply or undersupply of oil, gas and NGLs, the regulatory environment, the economic environment and other regional, national and international economic and political events, none of which can be predicted with certainty.

The Company operates in the exploration, development and production phase of the oil and gas industry. Its receivables include amounts due from purchasers of oil and gas production and amounts due from joint venture partners for their respective portions of operating expenses and exploration and development costs. The Company believes that no single customer or joint venture partner exposes the Company to significant credit risk. While certain of these customers and joint venture partners are affected by periodic downturns in the economy in general or in their specific segment of the natural gas or oil industry, the Company believes that its level of credit-related losses due to such economic fluctuations has been and will continue to be immaterial to the Company's results of operations in the long-term. Trade receivables are generally not collateralized. The Company analyzes customers' and joint venture partners' historical credit positions and payment histories prior to extending credit.

Concentrations of Credit Risk. Derivative financial instruments that hedge the price of oil, natural gas and NGLs are generally executed with major financial or commodities trading institutions which expose the Company to market and credit risks and may, at times, be concentrated with certain counterparties or groups of counterparties. The Company's policy is to execute financial derivatives only with major, creditworthy financial institutions. The Company has placed derivative instruments with eight different counterparties, of which all are lenders or affiliates of lenders in the Amended Credit Facility.

The creditworthiness of counterparties is subject to continuing review, and the Company believes all of these institutions currently are acceptable credit risks. Full performance is anticipated, and the Company has no past due receivables from any of its counterparties. Where the counterparty is a lender under the Amended Credit Facility, the counterparty risk is mitigated to the extent that the Company is indebted to such lender under the Amended Credit Facility.

13. Commitments and Contingencies

Lease Financing Obligation. The Company has a Lease Financing Obligation with Bank of America Leasing & Capital, LLC as the lead bank as discussed in Note 5. The aggregate undiscounted minimum future lease payments, including both principal and interest components, are presented below:

	As of December 31, 2014 (in thousands)
2015	$ 537
2016	537
2017	537
2018	537
2019	1,826
Thereafter	—
Total	$3,974

Transportation Charges. The Company entered into two firm transportation contracts to provide capacity on natural gas pipeline systems. The remaining term on these contracts is six years. The contracts require the Company to pay transportation charges regardless of the amount of pipeline capacity utilized by the Company. Beginning October 1, 2014, these transportation costs are included in unused commitments expense in the Consolidated Statements of Operations. As a result of the divestitures discussed in Note 4, the Company will likely not utilize the firm capacity on the natural gas pipelines.

The amounts in the table below represent the Company's future minimum transportation charges.

	As of December 31, 2014 (in thousands)
2015	$ 17,742
2016	18,692
2017	18,692
2018	18,692
2019	18,692
Thereafter	29,595
Total	$122,105

Purchase Commitments. The Company has one take-or-pay purchase agreement for supply of carbon dioxide ("CO2"), which has a total financial commitment of $1.7 million. The CO2 is for use in fracture stimulation operations. Under this contract, the Company is obligated to purchase a minimum monthly volume at a set price. If the Company takes delivery of less than the minimum required amount, the Company is responsible for full payment (deficiency payment) in December 2015.

Lease and Other Commitments. The Company leases office space, vehicles and certain equipment under non-cancelable operating leases. Additionally, the Company has entered into various long-term agreements for telecommunication services.

The Company has entered into a sales throughput contract in the South Altamont area of the Uinta Oil Basin. Under this contract, the Company is obligated to sell and deliver a minimum volume commitment ("MVC") of 450.0 MMcf for the period of December 1, 2014 to November 30, 2015. If the minimum volume is not delivered, the Company must make a deficiency payment in the amount of up to $0.8 million. This contract replaces the initial capital expenditures associated with the connection of South Altamont wells that would otherwise be incurred as connected. As of December 31, 2014, the Company had satisfied approximately 19.3 MMcf of this commitment, resulting in an estimated deficiency payment of up to $0.7 million due December 1, 2015.

Future minimum annual payments under lease and other agreements are as follows:

	As of December 31, 2014 (in thousands)
2015	$ 4,204
2016	2,838
2017	2,690
2018	2,525
2019	634
Thereafter	—
Total	$12,891

Litigation. The Company is subject to litigation, claims and governmental and regulatory proceedings arising in the course of ordinary business. It is the opinion of the Company's management that current claims and litigation involving the Company are not likely to have a material adverse effect on its consolidated balance sheets, cash flows or statements of operations.

14. Guarantor Subsidiaries

In addition to the Amended Credit Facility, the 7.625% Senior Notes, the 7.0% Senior Notes and the Convertible Notes, which are registered securities, are jointly and severally guaranteed on a full and unconditional basis by the Company's 100% owned subsidiaries ("Guarantor Subsidiaries"). Presented below are the Company's condensed consolidating balance sheets, statements of operations, statements of other comprehensive income (loss) and statements of cash flows, as required by Rule 3-10 of Regulation S-X of the Securities Exchange Act of 1934, as amended.

During the three months ended June 30, 2014, Bill Barrett Corporation, as parent, merged two of the Company's 100% owned subsidiaries, CBM Production Company and GB Acquisition Corporation, into the parent company. The condensed consolidating financial statements reflect the new guarantor structure for all periods presented.

The following condensed consolidating financial statements have been prepared from the Company's financial information on the same basis of accounting as the Consolidated Financial Statements. Investments in the subsidiaries are accounted for under the equity method. Accordingly, the entries necessary to consolidate the Company and the Guarantor Subsidiaries are reflected in the intercompany eliminations column.

Condensed Consolidating Balance Sheets

	As of December 31, 2014			
	Parent Issuer	Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
	(in thousands)			
Assets:				
Current assets	$ 426,103	$ 2	$ —	$ 426,105
Property and equipment, net	1,672,513	80,608	—	1,753,121
Intercompany receivable (payable)	59,592	(59,592)	—	—
Investment in subsidiaries	18,647	—	(18,647)	—
Noncurrent assets	65,258	—	—	65,258
Total assets	$2,242,113	$ 21,018	$(18,647)	$2,244,484
Liabilities and Stockholders' Equity:				
Current liabilities	$ 263,649	$ 1,038	$ —	$ 264,687
Long-term debt	803,222	—	—	803,222
Deferred income taxes	122,350	—	—	122,350
Other noncurrent liabilities	23,404	1,333	—	24,737
Stockholders' equity	1,029,488	18,647	(18,647)	1,029,488
Total liabilities and stockholders' equity	$2,242,113	$ 21,018	$(18,647)	$2,244,484

	As of December 31, 2013			
	Parent Issuer	Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
	(in thousands)			
Assets:				
Current assets	$ 154,986	$ 2,261	$ —	$ 157,247
Property and equipment, net	2,127,624	74,872	—	2,202,496
Intercompany receivable (payable)	59,076	(59,076)	—	—
Investment in subsidiaries	12,063	—	(12,063)	—
Noncurrent assets	21,770	—	—	21,770
Total assets	$2,375,519	$ 18,057	$(12,063)	$2,381,513
Liabilities and Stockholders' Equity:				
Current liabilities	$ 192,106	$ 613	$ —	$ 192,719
Long-term debt	979,082	—	—	979,082
Deferred income taxes	158,071	3,255	—	161,326
Other noncurrent liabilities	40,542	2,126	—	42,668
Stockholders' equity	1,005,718	12,063	(12,063)	1,005,718
Total liabilities and stockholders' equity	$2,375,519	$ 18,057	$(12,063)	$2,381,513

Condensed Consolidating Statements of Operations

	Year Ended December 31, 2014			
	Parent Issuer	Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
	(in thousands)			
Operating and other revenues	$ 447,907	$ 24,384	$ —	$ 472,291
Operating expenses	(497,258)	(17,800)	—	(515,058)
General and administrative	(53,361)	—	—	(53,361)
Interest income and other income (expense)	129,118	—	—	129,118
Income (loss) before income taxes and equity in earnings (loss) of subsidiaries	26,406	6,584	—	32,990
Provision for income taxes	(17,909)	—	—	(17,909)
Equity in earnings (loss) of subsidiaries	6,584	—	(6,584)	—
Net income (loss)	$ 15,081	$ 6,584	$(6,584)	$ 15,081

	Year Ended December 31, 2013			
	Parent Issuer	Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
	(in thousands)			
Operating and other revenues	$ 538,932	$ 29,161	$ —	$ 568,093
Operating expenses	(655,219)	(27,949)	—	(683,168)
General and administrative	(64,902)	—	—	(64,902)
Interest income and other income (expense)	(131,389)	—	—	(131,389)
Income (loss) before income taxes and equity in earnings (loss) of subsidiaries	(312,578)	1,212	—	(311,366)
Provision for income taxes	118,633	—	—	118,633
Equity in earnings (loss) of subsidiaries	1,212	—	(1,212)	—
Net income (loss)	$(192,733)	$ 1,212	$(1,212)	$(192,733)

	Year Ended December 31, 2012			
	Parent Issuer	Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
	(in thousands)			
Operating and other revenues	$ 683,319	$16,876	$ —	$ 700,195
Operating expenses	(599,215)	(9,105)	—	(608,320)
General and administrative	(68,666)	—	—	(68,666)
Interest and other income (expense)	(20,991)	—	—	(20,991)
Income (loss) before income taxes and equity in earnings (loss) of subsidiaries	(5,553)	7,771	—	2,218
Provision for income taxes	(1,636)	—	—	(1,636)
Equity in earnings (loss) of subsidiaries	7,771	—	(7,771)	—
Net income (loss)	$ 582	$ 7,771	$(7,771)	$ 582

Condensed Consolidating Statements of Comprehensive Income (Loss)

	Year Ended December 31, 2014			
	Parent Issuer	Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
	(in thousands)			
Net Income (Loss)	$15,081	$6,584	$(6,584)	$15,081
Other Comprehensive Income (Loss), net of tax:				
Effect of derivative financial instruments	(669)	—	—	(669)
Other comprehensive loss	(669)	—	—	(669)
Comprehensive Income (Loss)	$14,412	$6,584	$(6,584)	$14,412

	Year Ended December 31, 2013			
	Parent Issuer	Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
	(in thousands)			
Net Income (Loss)	$(192,733)	$1,212	$(1,212)	$(192,733)
Other Comprehensive Income (Loss), net of tax:				
Effect of derivative financial instruments	(4,663)	—	—	(4,663)
Other comprehensive loss	(4,663)	—	—	(4,663)
Comprehensive Income (Loss)	$(197,396)	$1,212	$(1,212)	$(197,396)

	Year Ended December 31, 2012			
	Parent Issuer	Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
	(in thousands)			
Net Income (Loss)	$ 582	$7,771	$(7,771)	$ 582
Other Comprehensive Income (Loss), net of tax:				
Effect of derivative financial instruments	(50,712)	—	—	(50,712)
Other comprehensive loss	(50,712)	—	—	(50,712)
Comprehensive Income (Loss)	$(50,130)	$7,771	$(7,771)	$(50,130)

Condensed Consolidating Statements of Cash Flows

	Year Ended December 31, 2014			
	Parent Issuer	Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
	(in thousands)			
Cash flows from operating activities	$ 241,628	$ 20,089	$ —	$ 261,717
Cash flows from investing activities:				
Additions to oil and gas properties, including acquisitions	(562,141)	(18,802)	—	(580,943)
Additions to furniture, fixtures and other	(3,658)	—	—	(3,658)
Proceeds from sale of properties and other investing activities	553,477	1,819	—	555,296
Intercompany transfers	3,156	—	(3,156)	—
Cash flows from financing activities:				
Proceeds from debt	165,000	—	—	165,000
Principal and redemption premium payments on debt	(283,546)	—	—	(283,546)
Intercompany transfers	—	(3,156)	3,156	—
Other financing activities	(2,557)	—	—	(2,557)
Change in cash and cash equivalents	111,359	(50)	—	111,309
Beginning cash and cash equivalents	54,545	50	—	54,595
Ending cash and cash equivalents	$ 165,904	$ —	$ —	$ 165,904

	Year Ended December 31, 2013			
	Parent Issuer	Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
	(in thousands)			
Cash flows from operating activities	$ 241,911	$ 23,354	$—	$ 265,265
Cash flows from investing activities:				
Additions to oil and gas properties, including acquisitions	(408,441)	(37,038)	—	(445,479)
Additions to furniture, fixtures and other	(2,254)	—	—	(2,254)
Proceeds from sale of properties and other investing activities	310,704	—	—	310,704
Cash flows from financing activities:				
Proceeds from debt	420,000	—	—	420,000
Principal and redemption premium payments on debt	(576,422)	—	—	(576,422)
Intercompany transfers	(13,684)	13,684	—	—
Other financing activities	3,336	—	—	3,336
Change in cash and cash equivalents	(24,850)	—	—	(24,850)
Beginning cash and cash equivalents	79,395	50	—	79,445
Ending cash and cash equivalents	$ 54,545	$ 50	$—	$ 54,595

	Year Ended December 31, 2012			
	Parent Issuer	Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
	(in thousands)			
Cash flows from operating activities	$ 372,331	$ 16,105	$—	$ 388,436
Cash flows from investing activities:				
Additions to oil and gas properties, including acquisitions	(925,012)	(33,642)	—	(958,654)
Additions to furniture, fixtures and other	(7,231)	—	—	(7,231)
Proceeds from sale of properties and other investing activities	328,888	—	—	328,888
Cash flows from financing activities:				
Proceeds from debt	875,826	—	—	875,826
Principal and redemption premium payments on debt	(595,386)	—	—	(595,386)
Intercompany transfers	(17,537)	17,537	—	—
Other financing activities	(9,765)	—	—	(9,765)
Change in cash and cash equivalents	22,114	—	—	22,114
Beginning cash and cash equivalents	57,281	50	—	57,331
Ending cash and cash equivalents	$ 79,395	$ 50	$—	$ 79,445

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS

(In Thousands, Except Per Share Data Unless Otherwise Indicated)
(Unaudited)

Oil and Gas Producing Activities

Costs Incurred. Costs incurred in oil and gas property acquisition, exploration and development activities and related depletion per equivalent unit-of-production were as follows:

	Year Ended December 31,		
	2014	2013	2012
	(in thousands, except per Boe data)		
Acquisition costs:			
Unproved properties (1)	$ 44,121	$ 13,728	$162,982
Proved properties (1)	49,660	370	6,033
Exploration costs	855	2,499	32,189
Development costs	549,982	455,543	754,485
Asset retirement obligation	7,264	3,455	8,324
Total costs incurred (1)	$651,882	$475,595	$964,013
Depletion per Boe of production	$ 25.15	$ 18.78	$ 16.26

(1) Year ended December 31, 2014 includes $79.0 million related to property acquired through asset exchanges, consisting of $29.3 million of unproved acquisition costs and $49.7 million of proved acquisition costs.

Supplemental Oil and Gas Reserve Information. The reserve information presented below is based on estimates of net proved reserves as of December 31, 2014, 2013 and 2012 that were prepared by internal petroleum engineers in accordance with guidelines established by the SEC and were audited by the Company's independent petroleum engineering firm NSAI in 2014, 2013 and 2012.

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and NGLs 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). Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Analysis of Changes in Proved Reserves. The following table sets forth information regarding the Company's estimated net total proved and proved developed oil and gas reserve quantities:

	Oil (MBbls)	Gas (MMcf)	NGLs (MBbls)	Equivalent Units (MBoe)
Proved reserves:				
Balance at December 31, 2011	30,603	1,181,073	—	227,449
Purchases of oil and gas reserves in place	253	290	—	301
Extension, discoveries and other additions	17,312	83,439	—	31,219
Revisions of previous estimates	6,583	(212,687)	—	(28,865)
Sales of reserves	(1,298)	(211,490)	—	(36,546)
Production	(2,687)	(101,486)	—	(19,601)
Balance at December 31, 2012	50,766	739,139	—	173,957
Purchases of oil and gas reserves in place	—	—	—	—
Extension, discoveries and other additions	44,505	120,231	11,076	75,620
Revisions of previous estimates (1)	(8,052)	(98,788)	26,879	2,362
Sales of reserves	(223)	(241,557)	—	(40,482)
Production	(3,495)	(52,685)	(2,199)	(14,475)
Balance at December 31, 2013	83,501	466,340	35,756	196,982
Purchases of oil and gas reserves in place	5,501	12,313	1,190	8,743
Extension, discoveries and other additions	15,665	26,103	2,188	22,204
Revisions of previous estimates	(9,866)	(47,749)	(4,342)	(22,166)
Sales of reserves	(6,951)	(281,389)	(20,479)	(74,329)
Production	(4,012)	(21,744)	(1,476)	(9,112)
Balance at December 31, 2014	83,838	153,874	12,837	122,322
Proved developed reserves:				
December 31, 2012	20,715	492,053	—	102,724
December 31, 2013	26,303	238,651	17,155	83,233
December 31, 2014	29,292	50,590	3,825	41,549
Proved undeveloped reserves:				
December 31, 2012	30,051	247,086	—	71,232
December 31, 2013	57,199	227,688	18,602	113,749
December 31, 2014	54,546	103,284	9,013	80,773

(1) The increase in NGL revisions of previous estimates from the year ended 2012 to the year ended 2013 includes the impact of the Company's conversion to three stream production. Prior to 2013, NGL reserves were included in natural gas data, which impacts the comparability for the periods presented.

At December 31, 2014, the Company revised its proved reserves downward by 22.2 MMBoe due to engineering revisions of 14.1 MMBoe and aging of proved undeveloped reserves in the Blacktail Ridge and Lake Canyon areas of the Uinta Basin of 8.1 MMBoe. Pricing for 2014 was $4.35 per MMBtu and $94.99 per barrel of oil compared with pricing for 2013 of $3.67 per MMBtu and $96.91 per barrel of oil, resulting in insignificant pricing revisions. Prices were adjusted by lease for quality, transportation fees and regional price differences.

At December 31, 2013, the Company revised its proved reserves upward by 2.2 MMBoe, excluding pricing revisions. The Company also revised its 2013 proved reserves upward by 0.2 MMBoe, as 2013 pricing was $3.67 per MMBtu and $96.91 per barrel of oil compared with the 2012 pricing of $2.56 per MMBtu and $91.21 per barrel of oil. Prices were adjusted by lease for quality, transportation fees and regional price differences.

At December 31, 2012, the Company revised its proved reserves downward by 15.0 MMBoe, excluding pricing revisions, due primarily to negative engineering revisions related to the 20-acre infill drilling performance at the West Tavaputs area in the Uinta Basin. At December 31, 2012, the Company also revised its 2012 proved reserves downward by 13.9 MMBoe, as 2012 pricing was $2.56 per MMBtu and $91.21 per barrel of oil compared with the 2011 pricing of $3.93 per MMBtu and $92.71 per barrel of oil. Prices were adjusted by lease for quality, transportation fees and regional price differences.

Standardized Measure. Certain information concerning the assumptions used in computing the valuation of proved reserves and their inherent limitations are discussed below. The Company believes such information is important for a proper understanding and assessment of the data presented.

For the years ended December 31, 2014, 2013 and 2012, future cash inflows are calculated by applying the 12-month average pricing (as is required by the rules of the Securities and Exchange Commission) of oil and gas relating to the Company's proved reserves to the year-end quantities of those reserves. For the year ended December 31, 2014, calculations were made using adjusted average prices of $79.96 per Bbl for oil, $34.17 per Bbl for NGLs and $3.79 per MMBtu for gas, as compared to the average benchmark prices of $94.99 per Bbl for oil, $39.65 per Bbl for NGLs and $4.35 per Mcf for gas. For the year ended December 31, 2013, calculations were made using adjusted average prices of $83.35 per Bbl for oil, $29.60 per Bbl for NGLs and $3.14 per MMBtu for gas, as compared to the average benchmark prices of $96.91 per Bbl for oil, $39.75 per Bbl for NGLs and $3.67 per Mcf for gas. For the year ended December 31, 2012, calculations were made using adjusted average prices of $78.85 per Bbl for oil and $3.68 per MMBtu for gas, as compared to the average benchmark prices of $91.21 per Bbl for oil and $2.56 per Mcf for gas. The differences between the average benchmark prices and the adjusted average prices used in the calculation of the standardized measure are attributable to adjustments made for transportation, quality and basis differentials. The Company also records an overhead charge against its future cash flows.

The assumptions used to calculate estimated future cash inflows do not necessarily reflect the Company's expectations of actual revenues or costs, nor their present worth. In addition, variations from the expected production rate also could result directly or indirectly from factors outside of the Company's control, such as unexpected delays in development, changes in prices or regulatory or environmental policies. The reserve valuation further assumes that all reserves will be disposed of by production. However, if reserves are sold in place, additional economic considerations could also affect the amount of cash eventually realized.

Future development and production costs are calculated by estimating the expenditures to be incurred in developing and producing the proved oil, gas and NGL reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions.

Future income tax expenses are calculated by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pre-tax net cash flows relating to the Company's proved oil, gas and NGL reserves. Permanent differences in oil and gas related tax credits and allowances are recognized.

The following table presents the standardized measure of discounted future net cash flows related to proved oil, gas and NGL reserves:

	Year Ended December 31,		
	2014	2013	2012
		(in thousands)	
Future cash inflows	$ 7,725,475	$ 9,482,577	$ 6,723,981
Future production costs	(2,265,328)	(2,742,616)	(2,094,349)
Future development costs	(1,636,744)	(2,070,575)	(1,285,894)
Future income taxes	(910,446)	(1,127,818)	(616,484)
Future net cash flows	2,912,957	3,541,568	2,727,254
10% annual discount	(1,743,375)	(2,164,019)	(1,560,551)
Standardized measure of discounted future net cash flows	$ 1,169,582	$ 1,377,549	$ 1,166,703

The "standardized measure" is the present value of estimated future cash inflows from proved oil, gas and NGL reserves, less future development and production costs and future income tax expenses, using prices and costs as of the date of estimation without future escalation, without giving effect to hedging activities, non-property related expenses such as general and administrative expenses, debt service and depreciation, depletion and amortization and discounted using an annual discount rate of 10% to reflect timing of future cash flows.

The present value (at a 10% annual discount) of future net cash flows from the Company's proved reserves is not necessarily the same as the current market value of its estimated oil, gas and NGL reserves. The Company bases the estimated discounted future net cash flows from its proved reserves on prices and costs in effect on the day of estimate in accordance with the applicable accounting guidance. However, actual future net cash flows from its oil, gas and NGL properties will also be affected by factors such as actual prices the Company receives for oil, gas and NGL, the amount and timing of actual production, supply of and demand for oil and natural gas and changes in governmental regulations or taxation.

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

A summary of changes in the standardized measure of discounted future net cash flows is as follows:

	Year Ended December 31, 2014	2013	2012
	(in thousands)		
Standardized measure of discounted future net cash flows, beginning of period	$1,377,549	$1,166,703	$1,616,088
Sales of oil and gas, net of production costs and taxes	(331,559)	(393,451)	(414,662)
Extensions, discoveries and improved recovery, less related costs	263,383	584,379	251,460
Quantity revisions	(416,642)	(23,484)	(603,726)
Price revisions	758,863	448,883	(371,954)
Previously estimated development costs incurred during the period	84,995	100,320	413,543
Changes in estimated future development costs	112	(33,455)	82,202
Accretion of discount	174,925	140,120	211,735
Purchases of reserves in place	105,885	—	3,358
Sales of reserves	(901,443)	(475,396)	(296,788)
Changes in production rates (timing) and other	(4,253)	126	8,690
Net changes in future income taxes	57,767	(137,196)	266,757
Standardized measure of discounted future net cash flows, end of period	$1,169,582	$1,377,549	$1,166,703

Quarterly Financial Data

The following is a summary of the unaudited quarterly financial data, including income before income taxes, net income and net income per common share for the years ended December 31, 2014 and 2013.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter (1)
	(in thousands, except per share data)			
Year Ended December 31, 2014				
Total revenues	$127,688	$145,008	$ 135,263	$ 64,332
Less: Costs and expenses	108,471	118,594	246,296	95,058
Operating income (loss)	$ 19,217	$ 26,414	$(111,033)	$ (30,726)
Income (loss) before income taxes	(22,994)	(37,830)	(56,503)	150,317
Net income (loss)	(12,749)	(26,586)	(34,649)	89,065
Net income (loss) per common share, basic	(0.27)	(0.55)	(0.72)	1.85
Net income (loss) per common share, diluted	(0.27)	(0.55)	(0.72)	1.84

(1) The decrease in total revenues and expenses in the fourth quarter was primarily due to asset sales during the third quarter. See Note 4 for additional details.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands, except per share data)			
Year Ended December 31, 2013				
Total revenues	$138,277	$142,299	$ 148,555	$138,962
Less: Costs and expenses	136,501	131,568	348,625	131,376
Operating income (loss)	$ 1,776	$ 10,731	$(200,070)	$ 7,586
Income (loss) before income taxes	(52,578)	22,876	(267,151)	(14,513)
Net income (loss)	(33,151)	14,273	(166,656)	(7,199)
Net income (loss) per common share, basic	(0.70)	0.30	(3.51)	(0.15)
Net income (loss) per common share, diluted	(0.70)	0.30	(3.51)	(0.15)

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Financial Statistics

FINANCIAL DATA	2014	2013	2012
Net Income (Loss), millions	$ 15.1	$ (192.7)	$ 0.6
Adjusted Earnings (Loss) per Dilutive Share	$ (0.52)	$ (0.43)	$ 0.15
Discretionary Cash Flow, millions	$ 232	$ 281	$ 403
Discretionary Cash Flow, per Dilutive Share	$ 4.78	$ 5.92	$ 8.51
Production Revenue, per Boe	$ 50.73	$ 39.35	$ 37.90
Lease Operating Expenses and Gathering, Transportation and Processing, per Boe	$ 10.51	$ 9.50	$ 9.15
Production Taxes, per Boe	$ 3.44	$ 1.88	$ 1.30
G&A, excluding non-cash stock-based compensation, per Boe	$ 4.61	$ 3.39	$ 2.66
Depletion, Depreciation and Amortization, per Boe	$ 25.88	$ 19.33	$ 17.49
Discretionary Cash Flow, per Boe	$ 25.41	$ 19.44	$ 20.55

AVERAGE REALIZED PRICES			
Natural Gas, including hedge effect, per Mcf*	$ 4.45	$ 4.16	$ 5.07
Oil Prices, including hedge effect, per Bbl	$ 79.51	$ 82.38	$ 84.96
NGL Prices, including hedge effect, per Bbl	$ 31.51	$ 28.31	$ N/A
Combined, per Boe	$ 50.73	$ 39.35	$ 37.90

*includes effect of NGL revenues in 2012

Operating Statistics

PROVED RESERVES AND ACREAGE	2014	2013	2012
Natural Gas, Bcf	154	466	739
Oil, MMBbls	83.8	83.5	50.8
NGLs, MMBbls	12.8	35.8	N/A
Oil Equivalents, MMBoe	122	197	174
Percent Developed	34%	42%	59%
Pre-Tax PV-10, millions	$ 1,484	$ 1,750	$ 1,401
Net Acreage, rounded	580,000	814,000	1,198,000

PRODUCTION			
Natural Gas, Bcf	21.7	52.7	101.5
Oil, MMBbls	4.0	3.5	2.7
NGLs, MMBbls	1.5	2.2	N/A
Oil Equivalents, MMBoe	9.1	14.5	19.6
Average Daily Production, MBoe/d	25.0	39.7	53.7
Percent Oil	44%	24%	14%

OPERATING STATISTICS			
Capital Expenditures, millions	$ 569	$ 474	$ 963
Producing Wells, gross/net	768/462	1,698/1,142	1,831/1,361
Wells Drilled, gross/net	94/73	164/86	327/220

BOARD OF DIRECTORS

Jim W. Mogg, Chairman of the Board, Past Chairman of DCP Midstream Partners

Carin M. Barth, President of LB Capital, Inc.

Kevin O. Meyers, Past Senior Vice President, Exploration and Production, Americas of ConocoPhillips and President of ConocoPhillips Canada

William F. Owens, Former Governor of Colorado

Edmund P. Segner, Past President and Chief of Staff of EOG Resources, Inc.

Randy I. Stein, Tax, Accounting and Business Consultant, Former Principal of PricewaterhouseCoopers LLP

Michael E. Wiley, Past Chairman and Chief Executive Officer of Baker Hughes Incorporated

OFFICERS

R. Scot Woodall, Chief Executive Officer and President

Robert W. Howard, Chief Financial Officer and Treasurer

Terry R. Barrett, Senior Vice President – Geosciences

David R. Macosko, Senior Vice President – Accounting

Larry A. Parnell, Senior Vice President – Business Development

Kenneth A. Wonstolen, Senior Vice President – General Counsel

Duane J. Zavadil, Senior Vice President – EH&S, Regulatory and Government Affairs

William M. Crawford, Vice President – Finance and Marketing

Jennifer Martin, Vice President – Investor Relations

Mitchell J. Reneau, Vice President – Land

Troy L. Schindler, Vice President – Drilling

William K. Stenzel, Vice President – Engineering and Planning

Jerry D. Vigil, Vice President – Information Technology

Michelle Vion, Vice President – Human Resources

Paul J. White, Vice President – Production

CORPORATE INFORMATION

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Denver, Colorado 80202
Telephone: 303-293-9100
Fax: 303-291-0420
www.billbarrettcorp.com

Investor Relations
Jennifer Martin
Vice President – Investor Relations
investor_relations@billbarrettcorp.com

Annual Shareholders' Meeting
Our Annual Shareholder's Meeting will be held at 8:30 a.m. (MDT) on Tuesday, May 12, 2015
Bill Barrett Corporation, Corporate Headquarters
1099 18th St, Suite 2300
Denver, CO 80202

Transfer Agent
Computershare
211 Quality Circle, Suite 210
College Station, TX 77845
www.computershare.com/investor

Independent Auditors
Deloitte & Touche LLP
Denver, Colorado

Independent Reservoir Engineers
Netherland, Sewell & Associates, Inc.
Dallas, Texas

DISCLOSURE STATEMENTS

Please reference the accompanying Form 10-K for the year-ended December 31, 2014, as well as current reports on Form 8-K and quarterly reports on Form 10-Q, for further information regarding the following disclosures. SEC filings are posted to the Company's website at www.billbarrettcorp.com.

Forward-Looking Statements
This report contains forward-looking statements. A number of potential risks and uncertainties could cause actual results to differ materially from projections and expectations. Please see the "Cautionary Note Regarding Forward-Looking Statements" and "Risks Related to the Oil and Natural Gas Industry and Our Business" in the accompanying 10-K.

Non-GAAP Measures
Non-GAAP measures included herein include Adjusted Net Income, Discretionary Cash Flow, Pre-Tax PV10 and General and Administrative Expenses before Non-Cash Stock-Based Compensation. These measures are included because management believes they are useful to investors in evaluating the Company's operating performance. These measures are widely used in the oil and natural gas industry. Calculations of these measures may differ by company. Please refer to the Company's fourth quarter and full year earnings releases dated February 25, 2015 and February 20, 2014 for reconciliations of these measures to the closest GAAP measure.