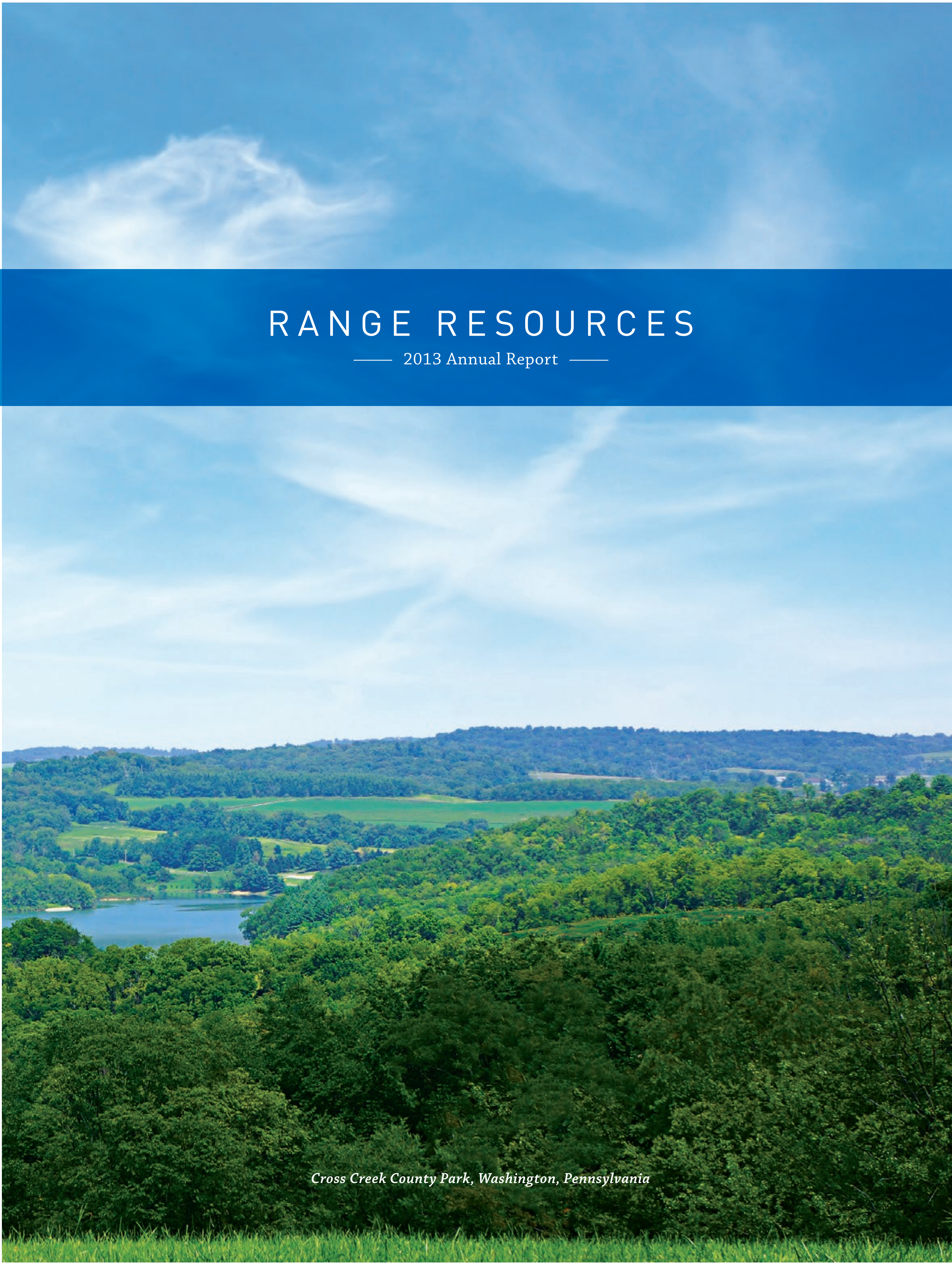
RANGE RESOURCES

2013 Annual Report



Cross Creek County Park, Washington, Pennsylvania

the CROSS CREEK PROJECT

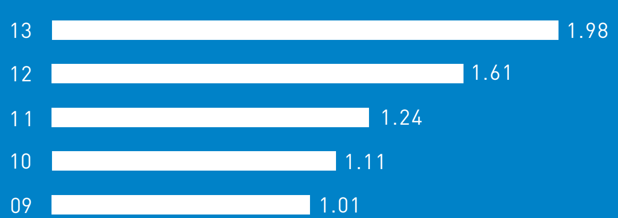
Range worked closely with the Washington County, Pennsylvania Board of County Commissioners to responsibly and effectively develop natural gas in Cross Creek County Park. The park was fully developed in three years, resulting in tens of millions of dollars in new and future revenues for the county, plus various improvements to the park.

> "Range has been a terrific partner from the very start, working closely with the Board of Commissioners and park staff on a daily basis. They were able to responsibly develop the gas beneath the 2,000 park acres while only impacting 1% of the surface, often times relying on previously cleared areas. The locations are not visible from parts of the park where people visit, making the impact even smaller, but the economic impacts will be positive for several generations."
>
> — LARRY MAGGI, *Washington County Board of Commissioners Chairman*

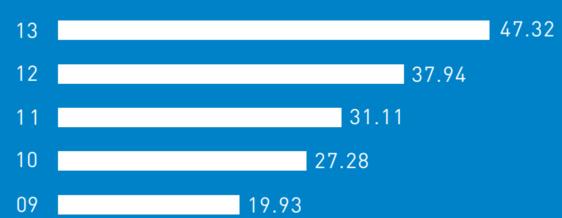
The successful partnership has served as a case study for other nearby bodies of government that manage public lands on how to maximize the benefits of natural gas development through modern technologies.

FINANCIAL HIGHLIGHTS

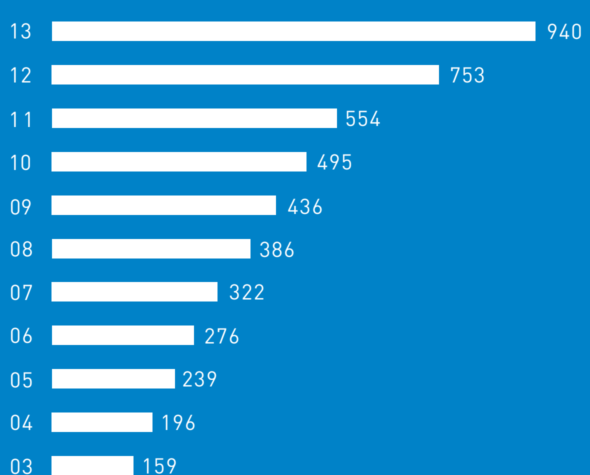
PRODUCTION PER SHARE DEBT ADJUSTED
(Mcfe)



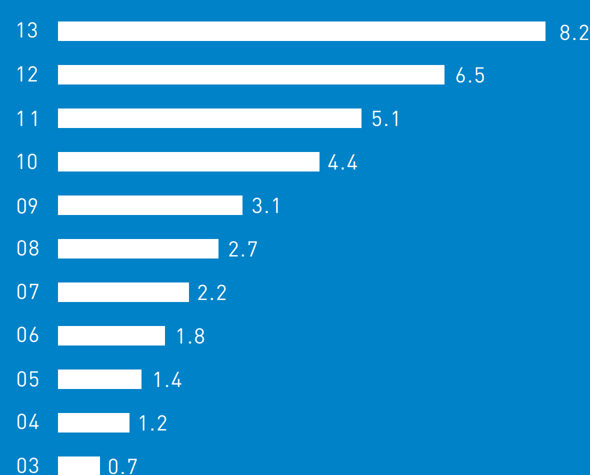
RESERVES PER SHARE DEBT ADJUSTED
(Mcfe)



PRODUCTION
(Mmcfe per day)



PROVED RESERVES
(Tcfe)



DEAR FELLOW SHAREHOLDERS:

2013 WAS A VERY GOOD YEAR FOR RANGE. WE POSTED ANOTHER PROFITABLE YEAR OF DOUBLE-DIGIT PRODUCTION AND RESERVE GROWTH, WHILE REDUCING COSTS AND BEING GOOD STEWARDS OF THE ENVIRONMENT AND THE COMMUNITIES WHERE WE LIVE AND WORK. LAST YEAR, WE GREW PRODUCTION 25% WITH A CAPITAL BUDGET OF $1.3 BILLION. CASH FLOW INCREASED 25% YEAR-OVER-YEAR, AND CASH FLOW PER SHARE, DEBT ADJUSTED, GREW 26% YEAR-OVER-YEAR. OUR PROVED RESERVES GREW 26% TO 8.2 TCFE, WHICH EQUATES TO REPLACING 612% OF OUR PRODUCTION.

The all-in cost to find and develop these reserves was $0.61 per mcfe. Reserves per share, debt adjusted, increased 25%, while production per share, debt adjusted, grew 26%.

As a result of our development activity, we have moved 6.4 Tcfe of unproved resource potential to proved reserves over the past four years. Because of this excellent performance, our total DD&A rate has declined 38%, from $2.33 per mcfe in 2009 to $1.44 in 2013. Looking at this same time period, our operating expense per mcfe declined 57%, from $0.83 per mcfe to $0.36. In short, Range is continuing to improve its capital and operating efficiency and the results are flowing through to the bottom line. Net income for 2013 was $116 million, up from $13 million in 2012.

In December, we reached two new production milestones as our gross Marcellus production reached one Bcfe per day and our corporate net production reached one Bcfe per day. Late last year, Sunoco Logistics' Mariner West project became fully operational and Enterprise's ATEX project started line fill in December, providing two very important ethane outlets for our Marcellus Shale production. In summary, 2013 was an excellent year in both operational and financial performance.

Looking to 2014, I believe there will be three key items that will distinguish performance among companies in our industry: (i) owning a sizable acreage position in the core area of one of the key plays, such as the Marcellus; (ii) the ability to consistently execute operationally and financially; and (iii) having a strong, forward-thinking marketing team. The first is critical because the application of the technology of horizontal drilling and multiple stage hydraulic fracturing has been applied to most of the domestic basins. Therefore, most of the major plays have more than likely been identified and are largely leased. The key, then, is to have a large concentrated acreage position in the core of one of the major plays. The economics are very different in the core versus non-core areas, due to differences in rock quality and the corresponding impact on the productivity of wells. Fortunately, our company has a huge position in the core of the Marcellus, which is the best natural gas play in North America - maybe the world, given the economics of the Marcellus and the risks elsewhere.

Second, I believe that the ability to consistently execute at a high level will be critical in 2014. At this point in time, the key plays and the resource potential in them are largely known. The key now will be to consistently drive up oil and gas production from these plays. Notably, Range has a 10-year track record of consistently meeting or exceeding its targets — a 10-year period with a 20% production CAGR. Although past performance does not guarantee future success in any industry, we have created a team and a culture that consistently performs, and meets or exceeds targets. Time after time, rather than succumbing to events like freezing weather, hurricanes and significant infrastructure delays, our team finds ways to overcome and achieve our targets.

Third, for 2014 and beyond, having a strong, forward-looking marketing team will be vital. Given the renaissance of the U.S. oil and gas business, supply is temporarily ahead of demand, although we see strong signs that demand growth is coming. We believe that Range is also well positioned to market our products as we execute a plan to grow production significantly. The best evidence for this, again, is our performance. After discovering the Marcellus Shale in 2004 and bringing the first well online in 2005, we knew the Marcellus Shale gas had very high Btu content and would not meet pipeline specifications because it contained so much ethane. Early on, some in the industry viewed gas this rich as a negative, and we were approached by some companies who wanted Range to pay a fee to them in order to “fix” our ethane problem. Rather than accept this as a solution, our team was very creative in building a diversified portfolio of three ethane markets based on three different pricing formulas that would not only ensure that our gas met pipeline quality specifications, but would also provide market price diversification and enable Range to grow production to greater than 3 Bcfe per day. Very importantly, rather than these solutions costing us money, our team’s solution enhances the value of the project. If all three marketing arrangements were fully operational today, Range’s ethane revenue would increase by about 25% compared to leaving ethane in the gas stream. That’s net of all transportation and processing costs and including additional propane recovery. We believe this is the best ethane sales portfolio of any company in the United States, and it’s a direct result of our team’s hard work and creativity.

We are currently selling our Appalachian Basin gas not only to customers in the northeast but also to customers located south, southeast and west of the basin. By 2017, our Marketing Team is working to have the capability of selling our Appalachian Basin gas to customers as far west as Wisconsin, on a line south to Texas, east to Florida and north to Maine. We are projecting that we could be able to move 4 to 5 Bcf per day of Appalachian gas to where two-thirds of the current United States demand for natural gas exists.

On the financial front, we strive to maintain a strong, flexible balance sheet to fund our operating strategy. Range continues to build economies of scale and our cost structure continues to improve, enhancing our competitiveness. Range’s continued operational success, combined with the lower interest rate macroeconomic environment, has resulted in a lower cost of capital.

I believe that we are well positioned for 2014 and beyond. We have a large footprint in the core of what we believe is the best gas play in the U.S., a technical and operations team that has demonstrated it can execute well, and a strong marketing team with a demonstrated track record. Our philosophy at Range is straightforward: to be good stewards for our shareholders, the environment and the communities where we live and work. It’s that simple. This core commitment starts with Range’s Board of Directors and extends to our over 800 employees. It’s this culture that has allowed us to continue to responsibly develop some of the most exciting and prolific assets in our industry, and it’s what will drive us well into the future.

I would like to welcome our newest Board member, Mary Ralph Lowe, who joined the Range Board in April of 2013. Mary Ralph has served as president and chief executive officer of Maralo, LLC, a private oil and gas exploration and production company, since 1973. She served on the Board of Apache Corporation from 1996 to 2002, and currently serves on numerous Boards including Texas Christian University, the Performing Arts Center of Fort Worth, the National Cowgirl Museum and Hall of Fame, and the Modern Art Museum of Fort Worth. Mary Ralph brings a wealth of knowledge and experience to the Board, and Range is fortunate to have her as a member of our Board.

Thanks to our employees for their dedication, hard work and creativity that made 2013 a success for Range. Thanks to our Board of Directors for their wisdom and guidance during the year. Thank you to our shareholders for your belief in our company and its future.

Jeffrey L. Ventura

JEFFREY L. VENTURA
President and Chief Executive Officer

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, 2013

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: 001-12209

RANGE RESOURCES CORPORATION

(Exact Name of Registrant as Specified in Its Charter)

Delaware	**34-1312571**
(State or Other Jurisdiction of Incorporation or Organization)	(IRS Employer Identification No.)
100 Throckmorton Street, Suite 1200, Fort Worth, Texas	**76102**
(Address of Principal Executive Offices)	(Zip Code)

Registrant's telephone number, including area code
(817) 870-2601

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

Title of Each Class	Name of each exchange on which registered
Common Stock, $.01 par value	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 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 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 (check one):

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 Act). Yes ☐ No ☒

The aggregate market value of the voting and non-voting common equity held by non-affiliates as of June 30, 2013 was $12,297,478,000. This amount is based on the closing price of registrant's common stock on the New York Stock Exchange on that date. Shares of common stock held by executive officers directors of the registrant are not included in the computation. However, the registrant has made no determination that such individuals are "affiliates" within the meaning of Rule 405 of the Securities Act of 1933.

As of February 24, 2014, there were 163,687,012 shares of Range Resources Corporation Common Stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's definitive proxy statement to be furnished to stockholders in connection with its 2014 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission within 120 days after the end of the fiscal year to which this report relates, are incorporated by reference in Part III, Items 10-14 of this report.

RANGE RESOURCES CORPORATION

Unless the context otherwise indicates, all references in this report to "Range," "we," "us" or "our" are to Range Resources Corporation and its wholly-owned subsidiaries and its ownership interests in equity method investments. Unless otherwise noted, all information in the report relating to natural gas, natural gas liquids and oil reserves and the estimated future net cash flows attributable to those reserves are based on estimates and are net to our interest. If you are not familiar with the oil and gas terms used in this report, please refer to the explanation of such terms under the caption "Glossary of Certain Defined Terms" at the end of Item 15 of this report.

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Disclosures Regarding Forward-Looking Statements

This Annual Report on Form 10-K, particularly Item 1. and 2. Business and Properties, Item 1A. Risk Factors, Item 3. Legal Proceedings, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, and Item 7A. Quantitative Disclosures about Market Risk, includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended and Section 21E of the Securities Exchange Act of 1934, as amended. These statements typically contain words such as "anticipate," "believe," "estimate," "expect," "forecast," "plan," "predict," "target," "project," "could," "should," "would" or similar words, indicating that future outcomes are uncertain. In accordance with "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995, these statements are accompanied by cautionary language identifying important factors, though not necessarily all such factors, that could cause future outcomes to differ materially from those set forth in the forward-looking statements.

Forward-looking statements in this Report may include, but are not limited to, levels of revenues, income from operations, net income or earnings per share; levels of capital and exploration expenditures; the success or timing of completion of ongoing or anticipated capital; exploration projects; volumes of production or sales of natural gas, natural gas liquids, and crude oil; levels of worldwide prices of crude oil; levels of domestic natural gas prices; levels of natural gas liquids, natural gas and crude oil reserves; the acquisition or divestiture of assets; the potential effect of judicial proceedings on our business and financial condition; and the anticipated effects of actions of third parties such as competitors, or federal, state or local regulatory authorities.

While management believes that these forward-looking statements are reasonable as and when made, there can be no assurance that future developments affecting us will be those that we anticipate. All comments concerning our expectations for future revenues and operating results are based on our forecasts for our existing operations and do not include the potential impact of any future acquisitions, should we choose to make any. Our forward-looking statements involve significant risks and uncertainties (some of which are beyond our control) and assumptions that could cause actual results to differ materially from our historical experience and our present expectations or projections. For a description of known material factors that could cause our actual results to differ from those in the forward-looking statements, see "Item 1A. Risk Factors."

Readers are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date hereof. We undertake no obligation to publicly update or revise any forward-looking statements after the date they are made, whether as a result of new information, future events or otherwise.

PART I

ITEMS 1 AND 2. BUSINESS AND PROPERTIES

General

Range Resources Corporation, a Delaware corporation, is a Fort Worth, Texas-based independent natural gas, natural gas liquids ("NGLs") and oil company, engaged in the exploration, development and acquisition of natural gas and oil properties, mostly in the Appalachian and Southwestern regions of the United States. Our corporate offices are located at 100 Throckmorton Street, Suite 1200, Fort Worth, Texas 76102 (telephone (817) 870-2601). Our common stock is listed and traded on the New York Stock Exchange (the "NYSE") under the symbol "RRC." At December 31, 2013, we had 163.4 million shares outstanding.

Our 2013 average production from operations consisted of the following:

- total production of 939.8 Mmcfe per day, an increase of 25% from 2012;
- 77% natural gas;
- natural gas production volume of 264.5 Bcf, an increase of 22% from 2012;
- NGLs production volume of 9.3 Mmbbls, an increase of 33% from 2012; and
- crude oil production volume of 3.8 Mmbbls, an increase of 34% from 2012.

At year-end 2013, our proved reserves had the following characteristics:

- 8.2 Tcfe of proved reserves;
- 69% natural gas;
- 51% proved developed;
- 85% operated;
- a reserve life index of 22 years (based on fourth quarter 2013 production);
- a pre-tax present value of $7.9 billion of future net cash flows attributable to our proved reserves, discounted at 10% per annum ("PV-10"[a]); and
- a standardized after-tax measure of discounted future net cash flows of $5.9 billion.

(a) PV-10 is considered a non-GAAP financial measure as defined by the SEC. We believe that the presentation of PV-10 is relevant and useful to our investors as supplemental disclosure to the standardized measure, or after-tax amount, because it presents the discounted future net cash flows attributable to our proved reserves before taking into account future corporate income taxes and our current tax structure. While the standardized measure is dependent on the unique tax situation of each company, PV-10 is based on prices and discount factors that are consistent for all companies. Because of this, PV-10 can be used within the industry and by creditors and securities analysts to evaluate estimated net cash flows from proved reserves on a more comparable basis. The difference between the standardized measure and the PV-10 amount is discounted estimated future income tax of $2.0 billion at December 31, 2013.

Available Information

Our internet website is available at http://www.rangeresources.com. Information contained on or connected to our website is not incorporated by reference into this Form 10-K and should not be considered part of this report or any other filing we make with the U.S. Securities and Exchange Commission (the "SEC"). We make available, free of charge, on our website, the annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports, as soon as reasonably practicable after filing such reports with the SEC. Other information such as presentations, our Corporate Governance Guidelines, the charters of the Audit Committee, the Compensation Committee, the Dividend Committee, and the Governance and Nominating Committee, and the Code of Business Conduct and Ethics are available on our website and in print to any stockholder who provides a written request to the Corporate Secretary at 100 Throckmorton Street, Suite 1200, Fort Worth, Texas 76102. Our Code of Business Conduct and Ethics applies to all directors, officers and employees, including the President and Chief Executive Officer and Chief Financial Officer.

The public may read and copy any materials that we file with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Washington, DC 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Also, the SEC maintains an internet website that contains reports, proxy and information statements, and other information regarding issuers, including Range, that file electronically with the SEC. The public can obtain any document we file with the SEC at http://www.sec.gov.

Our Business Strategy

Our objective is to build stockholder value through consistent growth in reserves and production on a cost-efficient basis. Our strategy to achieve our objective is to increase reserves and production through internally generated drilling projects coupled with occasional complementary acquisitions and divestiture of non-core assets. Our strategy requires us to make significant investments and financial commitments in technical staff, acreage, seismic data and technology to build drilling inventory and market our products. Our core strategy has the following principal elements:

- concentrate in core operating areas;
- maintain multi-year drilling inventory;
- focus on cost efficiency;
- commit to environmental protection, health and safety and community stewardship;
- maintain long-life reserve base;
- maintain operational and financial flexibility; and
- provide employee equity ownership and incentive compensation.

Concentrate in Core Operating Areas. We currently operate in two regions: the Appalachian (which includes Pennsylvania, Virginia, and West Virginia) and Southwestern (which includes the Permian Basin of West Texas, the Texas Panhandle, the Nemaha Uplift in Northern Oklahoma and Kansas and the Anadarko Basin of Western Oklahoma). Concentrating our drilling and producing activities in these core areas allows us to develop the regional expertise needed to interpret specific geological and operating trends and develop economies of scale. Operating in a number of core areas allows us to create a portfolio to assist in our goal of consistent production and reserve growth at attractive returns.

Maintain Multi-Year Drilling Inventory. We focus on areas with multiple prospective, productive horizons and development opportunities. We use our technical expertise to build and maintain a multi-year drilling inventory. We believe that a large, multi-year inventory of drilling projects increases our ability to efficiently plan for the economic growth of production and reserves. Currently, we have over 12,000 proven and unproven drilling locations in inventory. Our focus is to grow year-over-year production by 20-25% by focusing on developing fields in our operating regions.

Focus on Cost Efficiency. We concentrate in core areas which we believe to have sizeable hydrocarbon deposits in place that will allow us to consistently increase production while controlling costs. As there is little long-term competitive sales price advantage available to a commodity producer, the costs to find, develop, and produce a commodity are important to organizational sustainability and long-term shareholder value creation. We endeavor to control costs such that our cost to find, develop and produce natural gas and oil is one of the lowest cost structures in the industry. We operate a significant portion of our total net production and believe that our extensive knowledge of the geologic and operating conditions in the areas where we operate provides us with the ability to achieve operational efficiencies.

Commit to Environmental Protection, Health and Safety and Community Stewardship. We strive to implement the latest technologies and best commercial practices to minimize potential impacts from the development of our natural resources on the environment, worker health and safety, and the health and safety of the communities where we operate. Working with peer companies, regulators, nongovernmental organizations, industries not related to the natural gas industry, and other engaged stakeholders, we consistently analyze and review performance while striving for continual improvement. In July 2010, we voluntarily elected to provide, on our website, the hydraulic fracturing additives for all wells operated by us and completed to the Marcellus Shale formation. We participate in FracFocus, a national publically accessible web-based registry to report, on a well-by-well basis, the additives and chemicals and amount of water used in the hydraulic fracturing process for each of the wells we operate. We encourage every employee to maintain safe operations, minimize environmental impact and conduct their daily business with the highest of ethical standards.

Maintain Long-Life Reserve Base. Long-life natural gas and oil reserves provide a more stable growth platform than short-life reserves. Long-life reserves reduce reinvestment risk as they lessen the amount of reinvestment capital deployed each year to replace production. Long-life natural gas and oil reserves also assist us in minimizing costs as stable production makes it easier to build and maintain operating economies of scale. We use our drilling, divestiture and acquisition activities to assist in executing this strategy.

Maintain Operational and Financial Flexibility. Because of the risks involved in drilling, coupled with changing commodity prices, we are flexible and adjust our capital budget throughout the year. If certain areas generate higher than anticipated returns, we may accelerate development in those areas and decrease expenditures elsewhere. We also believe in maintaining a strong balance sheet, ample liquidity and using commodity derivatives to stabilize our realized prices. This allows us to be more opportunistic in lower price environments and provides more consistent cash flows and financial results.

Provide Employee Equity Ownership and Incentive Compensation. We want our employees to think and act like stockholders. To achieve this, we reward and encourage them through equity ownership in Range. All full-time employees are eligible to receive equity grants. As of December 31, 2013, our employees owned equity securities in our benefit plans (vested and unvested) that had an aggregate market value of approximately $413.0 million.

Significant Accomplishments in 2013

- ***Production growth*** – In 2013, our production averaged 939.8 Mmcfe per day, an increase of 25% from 2012. Targeted drilling in the Marcellus Shale play in Pennsylvania drove our production growth.
- ***Reserve growth*** – Total proved reserves increased 26% in 2013 to 8.2 Tcfe, marking the twelfth consecutive year our proved reserves have increased. This achievement is the result of continued drilling success, as all of our production and reserve growth in 2013 came from our drilling program. While consistent growth is challenging to sustain, we believe the quality of our technical teams and our substantial inventory of drilling locations provide the basis for future reserve, production and cash flow growth.
- ***Successful drilling program*** – In 2013, we drilled 219 gross natural gas and oil wells plus an additional 6 service wells. We replaced 505% of our production through drilling in 2013 and our overall drilling success rate was 99%. We continue to build our drilling inventory which is critical to our ability to drill a large number of wells each year on a cost effective and efficient basis.
- ***Large resource potential from unconventional and conventional plays*** – Maintaining a large exposure to potential resources is important. We continued expansion of our unconventional resource shale plays in 2013. We have 5 large unconventional and prospective plays – the Marcellus, Utica/Point Pleasant and Upper Devonian shales in Pennsylvania, the Huron Shale in Virginia and the Cline Shale in West Texas. These plays cover expansive areas, provide multi-year drilling opportunities and, collectively, have sustainable lower risk growth profiles. The economics of these plays have been enhanced by continued advancements in drilling and completion technologies. We have expanded into the conventional horizontal Mississippian play in Northern Oklahoma and Kansas. We have leased 1.3 million net acres in these 5 shale plays and approximately 160,000 net acres in the Mississippian. We also have approximately 155,000 net acres in our coal bed methane plays in Virginia.
- ***Continued development of processing and pipeline takeaway capacity and marketing of NGLs*** – We continue to ensure we have sufficient processing capacity and marketing agreements in place for our production. In 2011, we entered into an ethane sales contract where a third party will transport ethane from the tailgate of a third-party processing and fractionation facility to the international border for further delivery into Canada. Initial deliveries under this agreement commenced in second half 2013. Also in 2011, we entered into an agreement to transport ethane to the Gulf Coast for which initial deliveries also commenced in late 2013. We also transport propane by rail to the Philadelphia harbor for sales to domestic and international customers. During the year, we entered into additional firm transportation agreements to provide gas gathering and transportation from southwestern and northeastern Pennsylvania. At December 31, 2013, our agreements provide commitments that total 1.3 Bcfe per day.
- ***Focus on financial flexibility*** – Debt per mcfe of proved reserves was $0.38 at December 31, 2013 compared to $0.44 at December 31, 2012. In March 2013, we issued $750.0 million of senior subordinated fixed rate 5.00% notes having a 10-year maturity. The proceeds we received from the issuance of the 5.00% senior subordinated notes were used to reduce the outstanding balance on our bank credit facility. The issuance helped to better align the maturity schedule of our debt with the long-term life of our assets and reduce interest rate volatility. In May 2013, we redeemed all $250.0 million aggregate principal amount of our 7.25% senior subordinated notes due 2018 with borrowings under our bank credit facility. As of December 31, 2013, we maintain a $2.0 billion bank credit facility and our committed borrowing capacity on that date was $1.75 billion.
- ***Successful land acquisitions completed*** – In 2013, we leased or renewed $137.5 million of acreage located in our core areas, primarily in the Marcellus Shale and the conventional horizontal Mississippian play in Northern Oklahoma and Kansas. We continued to see outstanding results in the Marcellus Shale. Production in the Marcellus Shale increased 39% while we continue to prove up acreage, acquire additional acreage and gain access to additional pipeline and processing capacity.
- ***Successful dispositions completed*** – In April 2013, we sold our Delaware Basin and Permian Basin properties in Southeast New Mexico and West Texas for gross proceeds of $275.0 million. We also received $40.5 million of additional proceeds primarily related to the sale of miscellaneous proved and unproved properties.

Industry Operating Environment

We operate entirely within the continental United States. As traditional basins in the U.S. have matured, exploration and production has shifted to unconventional "resource" plays, typically shale reservoirs that historically were not thought to be economically productive for natural gas and oil. These plays cover large areas, provide multi-year inventories of drilling opportunities and, with modern oil and gas technology, have sustainable lower risk and higher growth profiles if located in the core area of each play. The economics of these plays have been enhanced by continued advancements in drilling and completion technologies. These advancements make these plays more resilient to lower commodity prices while increasing the domestic supply of natural gas and oil. Examples of such technological advancements include advanced 3-D seismic processing, hydraulic fracture stimulation using almost one hundred percent sand and water, advances in well logging and analysis, horizontal drilling and completion technologies and automated remote well monitoring and emission control devices.

The oil and natural gas industry is affected by many factors that we cannot control. Government regulations, particularly in the areas of taxation, energy, climate change and the environment, can have a significant impact on operations and profitability. The impact of these factors is extremely difficult to accurately predict or anticipate. Although it is difficult for us to predict the occurrence of events that may affect commodity prices or the degree to which these prices will be affected, the prices for any commodity we produce will generally approximate current market prices in the geographic region of the production.

Natural gas prices are generally determined by North American supply and demand. The New York Mercantile Exchange ("NYMEX") monthly settlement prices for natural gas averaged $3.67 per mcf in 2013, with a high of $4.19 per mcf in June and a low of $3.32 per mcf in February. Natural gas prices continue to be under pressure due to concerns over excess supply of natural gas due to the high productivity of shale plays in the United States and continued slow growth in demand. This decrease in demand is somewhat offset by an increase in the use of natural gas for power generation.

Significant factors that will impact 2014 crude oil prices include worldwide economic conditions, political and economic developments in the Middle East, demand in Asian and European markets, and the extent to which members of the Organization of Petroleum Exporting Countries and other oil exporting nations are able to manage oil supply through export quotas. NYMEX monthly settlement prices for oil averaged $98.20 per barrel in 2013, with a high of $106.54 per barrel in August and a low of $92.07 per barrel in April.

NGLs prices are generally determined by North American supply and demand. We expect NGLs prices in 2014 to continue to be under pressure due to concerns over excess supply and variable weather patterns.

Natural gas, NGLs and oil prices affect:

- the amount of cash flow available to us for capital expenditures;
- our ability to borrow and raise additional capital;
- the quantity of natural gas, NGLs and oil that we can economically produce; and
- revenues and profitability.

Natural gas prices are likely to affect us more than oil prices because approximately 69% of our proved reserves is natural gas. Any continued or extended decline in natural gas, NGLs and oil prices could have a material adverse effect on our financial position, results of operations, cash flows and access to capital. To achieve more predictable cash flows and to reduce our exposure to downward price fluctuations, we currently, and may in the future, use derivative instruments to hedge future sales prices on our natural gas, NGLs and oil production. The use of derivative instruments has in the past and may in the future, prevent us from realizing the full benefit of upward price movements but also partially protects us from declining price movements.

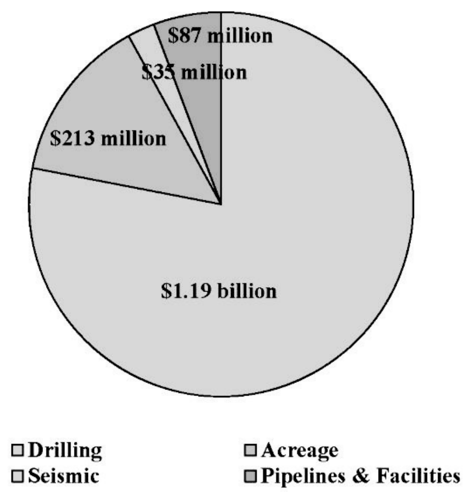
Segment and Geographical Information

Our operations consist of one reportable segment. We have a single, company-wide management team that administers all properties as a whole rather than by discrete operating segments. We track only basic operational data by area. We do not maintain complete separate financial statement information by area. We measure financial performance as a single enterprise and not on an area-by-area basis. Our operations are limited to the United States and we focus on both unconventional resource plays and conventional plays in the Appalachian and Southwestern regions of the United States.

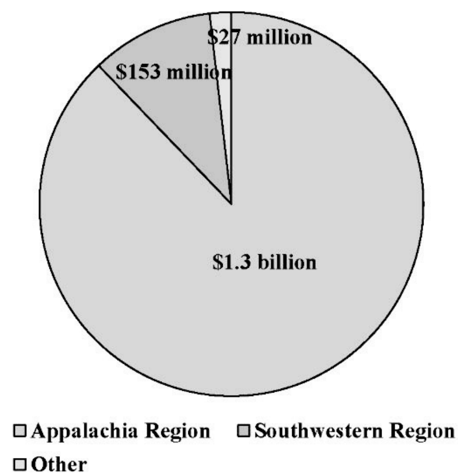
Outlook for 2014

Our capital expenditure budget for 2014 has been initially set at approximately $1.52 billion. As has been our historical practice, we will periodically review our capital expenditures throughout the year and adjust the budget based on commodity prices, drilling success and markets for our products. At December 31, 2013, approximately 80% of our expected 2014 natural gas, NGLs and oil production is hedged. For a complete discussion of our hedging activities, a listing of open contracts at December 31, 2013 and the estimated fair value of these contracts as of that date, see Note 11 to our consolidated financial statements. Our estimated 2014 capital expenditure budget detail and budget by area are shown below:

2014 Capital Budget Detail



2014 Capital Budget by Area



Production, Price and Cost History

The following table sets forth information regarding natural gas, NGLs and oil production, realized prices and production costs for the last three years. For more information, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

	Year Ended December 31,		
	2013	2012	2011
Production			
Natural gas (Mmcf)	264,528	216,555	145,206
Natural gas liquids (Mbbls)	9,255	6,967	5,352
Crude oil and condensate (Mbbls)	3,827	2,851	1,960
Total (Mmcfe) [(a)]	343,022	275,465	189,077
Average sales prices (wellhead)			
Natural gas (per mcf)	$ 3.61	$ 2.83	$ 4.21
Natural gas liquids (per bbl)	34.07	38.05	50.23
Crude oil and condensate (per bbl)	86.00	83.46	86.22
Total (per mcfe) [(a)]	4.66	4.05	5.55
Average realized prices (including derivatives that qualify for hedge accounting):			
Natural gas (per mcf)	$ 4.03	$ 3.93	$ 5.06
Natural gas liquids (per bbl)	34.07	38.05	50.23
Crude oil and condensate (per bbl)	87.47	82.77	86.22
Total (per mcfe) [(a)]	5.00	4.91	6.21
Average realized prices (including all derivative settlements and third party transportation costs)			
Natural gas (per mcf)	$ 3.08	$ 3.11	$ 4.43
Natural gas liquids (per bbl)	31.29	41.03	50.82
Crude oil and condensate (per bbl)	84.70	83.64	81.34
Total (per mcfe) [(a)]	4.16	4.35	5.68
Production costs			
Lease operating (per mcfe)	$ 0.34	$ 0.39	$ 0.57
Workovers (per mcfe)	0.02	0.02	0.02
Stock-based compensation (per mcfe)	0.01	0.01	0.01
Total (per mcfe)	$ 0.37	$ 0.42	$ 0.60

[(a)] Oil and NGLs are converted at the rate of one barrel equals six mcf based upon the approximate relative energy content of oil to natural gas, which is not necessarily indicative of the relationship of oil and natural gas prices.

Proved Reserves

The following table sets forth our estimated proved reserves for 2013, 2012 and 2011 based on the average of prices on the first day of each month of the given calendar year, in accordance with the SEC rules that became effective on December 31, 2009. Oil includes both crude oil and condensate. We have no natural gas, NGLs or oil reserves from non-traditional sources. Additionally, we do not provide optional disclosures of probable or possible reserves.

	Summary of Oil and Gas Reserves of Fiscal Year-End Based on Average Fiscal-Year Prices				
Reserve Category	Natural Gas (Mmcf)	NGLs (Mbbls)	Oil (Mbbls)	Total (Mmcfe) [a]	%
2013:					
Proved					
Developed	2,797,483	206,477	26,054	4,192,666	51%
Undeveloped	2,868,162	167,935	22,306	4,009,608	49%
Total Proved	5,665,645	374,412	48,360	8,202,274	100%
2012:					
Proved					
Developed	2,373,604	154,984	25,667	3,457,502	53%
Undeveloped	2,419,072	85,415	19,415	3,048,068	47%
Total Proved	4,792,676	240,399	45,082	6,505,570	100%
2011:					
Proved					
Developed	1,907,209	64,472	17,872	2,401,274	48%
Undeveloped	2,102,467	78,043	13,660	2,652,687	52%
Total Proved	4,009,676	142,515	31,532	5,053,961	100%

(a) Oil and NGLs are converted to mcfe at the rate of one barrel equals six mcf based upon the relative energy content of oil to natural gas, which is not indicative of the relationship of oil and natural gas prices.

The following table sets forth summary information by area with respect to estimated proved reserves at December 31, 2013:

	Reserve Volumes					PV-10 [a]	
	Natural Gas (Mmcf)	NGLs (Mbbls)	Oil (Mbbls)	Total (Mmcfe)	%	Amount (In thousands)	%
Appalachian Region	5,327,652	340,834	27,757	7,539,201	92%	$ 6,916,206	88%
Southwestern Region	337,993	33,578	20,603	663,073	8%	981,338	12%
Total	5,665,645	374,412	48,360	8,202,274	100%	$ 7,897,544	100%

(a) PV-10 was prepared using the twelve-month average prices for 2013, discounted at 10% per annum. Year-end PV-10 is a non-GAAP financial measure as defined by the SEC. We believe that the presentation of PV-10 is relevant and useful to our investors as supplemental disclosure to the standardized measure, or after tax amount, because it presents the discounted future net cash flows attributable to our proved reserves prior to taking into account future corporate income taxes and our current tax structure. While the standardized measure is dependent on the unique tax situation of each company, PV-10 is based on prices and discount factors that are consistent for all companies. Because of this, PV-10 can be used within the industry and by creditors and securities analysts to evaluate estimated net cash flows from proved reserves on a more comparable basis. The difference between the standardized measure and the PV-10 amount is the discounted estimated future income tax of $2.0 billion at December 31, 2013. Included in the $7.9 billion pre-tax PV-10 is $5.4 billion related to proved developed reserves.

Reserve Estimation

All reserve information in this report is based on estimates prepared by our petroleum engineering staff. We also have the following independent petroleum consultants conduct an audit of our year-end reserves: DeGolyer and MacNaughton (Southwestern) and Wright and Company, Inc. (Appalachian). These engineers were selected for their geographic expertise and their historical experience in engineering certain properties. The proved reserve audits performed for 2013, 2012 and 2011, in the aggregate represented 96%, 93% and 89% of our proved reserves. The reserve audits performed for 2013, 2012 and 2011, in the aggregate represented 97%, 88% and 87% of our 2013, 2012 and 2011 associated pre-tax present value of proved reserves discounted at ten percent. Copies of the summary reserve reports prepared by each of these independent petroleum consultants are included as an exhibit to this Annual Report on Form 10-K. The technical person at each independent petroleum consulting firm responsible for reviewing the reserve estimates presented herein meets the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with our independent petroleum consultants to ensure the integrity, accuracy and timeliness of data furnished to independent petroleum consultants for their reserve audit process. Throughout the year, our technical team meets periodically with representatives of each of our independent petroleum consultants to review properties and discuss methods and assumptions. Our senior management reviews and approves significant changes to our proved reserves. We provide historical information to our consultants for our largest producing properties such as ownership interest, natural gas, NGLs and oil production, well test data, commodity prices and operating and development costs. The consultants perform an independent analysis and differences are reviewed with our Senior Vice President of Reservoir Engineering and Economics. In some cases, additional meetings are held to review identified reserve differences. The reserve auditor estimates of proved reserves and the pre-tax present value of such reserves discounted at 10% did not differ from our estimates by more than 10% in the aggregate. However, when compared on a lease-by-lease, field-by-field or area-by-area basis, some of our estimates may be greater than those of the auditors and some may be less than the estimates of the reserve auditors. When such differences do not exceed 10% in the aggregate, our reserve auditors are satisfied that the proved reserves and pre-tax present value of such reserves discounted at 10% are reasonable and will issue an unqualified opinion. Remaining differences are not resolved due to the limited cost benefit of continuing such analysis.

Historical variances between our reserve estimates and the aggregate estimates of our independent petroleum consultants have been less than 5%. All of our reserve estimates are reviewed and approved by our Senior Vice President of Reservoir Engineering and Economics, who reports directly to our President and Chief Executive Officer. Our Senior Vice President of Reservoir Engineering and Economics holds a Bachelor of Science degree in Electrical Engineering from the Pennsylvania State University. Before joining Range, he held various technical and managerial positions with Amoco, Hunt Oil and Union Pacific Resources and has more than thirty years of engineering experience in the oil and gas industry. During the year, our reserves group may also perform separate, detailed technical reviews of reserve estimates for significant acquisitions or for properties with problematic indicators such as excessively long lives, sudden changes in performance or changes in economic or operation conditions. We did not file any reports during the year ended December 31, 2013 with any federal authority or agency with respect to our estimate of natural gas and oil reserves.

Reserve Technologies

Proved reserves are those quantities of natural gas, natural gas liquids and oil, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations. The term “reasonable certainty” implies a high degree of confidence that the quantities of natural gas, NGLs and oil actually recovered will equal or exceed the estimate. To achieve reasonable certainty, our internal technical staff employs technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used in the estimation of our proved reserves include, but are not limited to, empirical evidence through drilling results and well performance, well logs, geologic maps and available downhole and production data, seismic data, well test data and reservoir simulation modeling.

Reporting of Natural Gas Liquids

We produce natural gas liquids, or NGLs, as part of the processing of our natural gas. The extraction of NGLs in the processing of natural gas reduces the volume of natural gas available for sale. At December 31, 2013, NGLs represented approximately 27% of our total proved reserves on an mcf equivalent basis. NGLs are products priced by the gallon (and sold by the barrel) to the end-user. In reporting proved reserves and production of NGLs, we have included production and reserves in barrels. Prices for a barrel of NGLs in 2013 averaged approximately 60% lower than the average prices for equivalent volumes of oil. We report all production information related to natural gas net of the effect of any reduction in natural gas volumes resulting from the processing of NGLs. As of December 31, 2013, we have 676 Bcfe of ethane reserves (112.6 Mmbbls) associated with our Marcellus Shale, which are included in NGLs proved reserves.

Proved Undeveloped Reserves (PUDs)

As of December 31, 2013, our PUDs totaled 22.3 Mmbbls of crude oil, 167.9 Mmbbls of NGLs and 2.9 Tcfe of natural gas, for a total of 4.0 Tcfe. Costs incurred in 2013 relating to the development of PUDs were approximately $504.1 million. Approximately 90% of our PUDs at year-end 2013 were associated with our major development area in the Marcellus Shale. All PUD drilling locations are scheduled to be drilled prior to the end of 2018 with more than 75% of the future development costs to be spent in the next three years. Changes in PUDs that occurred during the year were due to:

- conversion of approximately 434 Bcfe of PUDs into proved developed reserves;
- new PUDs added consisting of 1,185 Bcfe;

- 234 Bcfe positive revision with improved recovery partially offset by reserves reclassified to unproved because of a slower pace of development activity beyond the five-year development horizon; and
- 23 Bcfe reduction from the sale of properties.

Proved Reserves (PV-10)

The following table sets forth the estimated future net cash flows, excluding open derivative contracts, from proved reserves, the present value of those net cash flows discounted at a rate of 10% (PV-10), and the expected benchmark prices and average field prices used in projecting net cash flows over the past five years. Our reserve estimates do not include any probable or possible reserves. Field prices, or wellhead prices reported below, are net of third party transportation, gathering and compression expenses (in millions, except prices):

	2013	2012	2011	2010	2009
Future net cash flows	$ 21,029	$ 11,156	$ 15,610	$ 12,516	$ 6,721
Present value					
Before income tax	7,898	3,960	6,084	4,647	2,593
After income tax (Standardized Measure)	5,862	3,224	4,515	3,479	2,091
Benchmark prices (NYMEX)					
Gas price (per mcf)	3.67	2.76	4.12	4.38	3.87
Oil price (per barrel)	97.33	95.05	95.61	79.81	60.85
Wellhead prices					
Gas price (per mcf)	3.75	2.75	3.55	3.70	3.19
Oil price (per barrel)	86.66	86.91	85.59	72.51	54.65
NGLs price (per barrel)	25.93	32.23	49.24	39.14	34.05

Future net cash flows represent projected revenues from the sale of proved reserves net of production and development costs (including operating expenses and production taxes) and revenues are based on a twelve-month unweighted average of the first day of the month pricing, without escalation. Future cash flows are reduced by estimated production costs, administrative costs, costs to develop and produce the proved reserves and abandonment costs, all based on current year-end economic conditions. There can be no assurance that the proved reserves will be produced in the future or that prices, production or development costs will remain constant. There are numerous uncertainties inherent in estimating reserves and related information and different reservoir engineers often arrive at different estimates for the same properties.

Property Overview

Our natural gas and oil operations are concentrated in the Appalachian and Southwestern regions of the United States. Our properties consist of interests in developed and undeveloped natural gas and oil leases in these regions. These interests entitle us to drill for and produce natural gas, NGLs, crude oil and condensate from specific areas. Our interests are mostly in the form of working interests and, to a lesser extent, royalty and overriding royalty interests. We have a single company-wide management team that administers all properties as a whole. We track only basic operational data by area. We do not maintain complete separate financial statement information by area. We measure financial performance as a single enterprise and not on an area-by-area basis.

The table below summarizes data for our operating regions for the year ended December 31, 2013.

Region	Average Daily Production (mcfe per day)	Production (mmcfe)	Percentage of Production	Proved Reserves (mmcfe)	Percentage of Proved Reserves
Appalachian	814,369	297,245	87%	7,539,201	92%
Southwestern	125,417	45,777	13%	663,073	8%
Total	939,786	343,022	100%	8,202,274	100%

The following table summarizes our costs incurred by operating region for the year ended December 31, 2013 (in thousands):

	Acreage Purchases	Development Costs	Exploration Costs	Gathering Facilities	Asset Retirement Obligations	Total
Appalachian	$ 127,892	$ 720,832	$ 234,673	$ 37,625	$ 69,412	$ 1,190,434
Southwestern	9,646	217,836	19,478	9,461	6,961	263,382
Total costs incurred	$ 137,538	$ 938,668	$ 254,151	$ 47,086	$ 76,373	$ 1,453,816

Approximately 83% of our proved reserves at December 31, 2013 are located in the Marcellus Shale in our Appalachia region. This play has a large portfolio of drilling opportunities. The following table below sets forth annual production volumes, average sales prices and production cost data for our Marcellus Shale field which, as of December 31, 2013, is our only field in which reserves are greater than 15% of our total proved reserves.

Marcellus Shale Field	2013	2012	2011
Production:			
Natural gas (Mmcf)	203,926	149,589	80,554
NGLs (Mbbls)	7,213	5,034	3,423
Crude oil and condensate (Mbbls)	2,529	1,564	695
Total Mmcfe [(a)]	262,377	189,178	105,264
Sales Prices: [(b)]			
Natural gas (per mcf)	$ 2.59	$ 1.86	$ 3.17
NGLs (per bbl)	33.19	38.48	51.83
Crude oil and condensate (per bbl)	82.11	78.56	74.84
Total (per mcfe)	3.72	3.14	4.60
Production Costs:			
Lease operating (per mcfe)	$ 0.16	$ 0.18	$ 0.33
Production and ad valorem tax (per mcfe) [(c)]	0.11	0.26	—

(a) Oil and NGLs are converted at the rate of one barrel equals six mcf based upon the approximate relative energy content of oil to natural gas, which is not indicative of the relationship of oil and natural gas prices.
(b) We do not record hedging or the results of hedging at the field level. Includes deductions for third party transportation, gathering and compression expense.
(c) Includes Pennsylvania impact fee.

Appalachian Region

Our properties in this area are located in the Appalachian Basin in the northeastern United States, principally in Pennsylvania, West Virginia and Virginia. The reserves principally produce from the Marcellus Shale, the Pennsylvanian (coalbed formation), Berea, Big Lime, Huron Shale, Medina and Upper Devonian formations at depths ranging from 2,500 feet to 9,000 feet. We own 6,136 net producing wells, 84% of which we operate. Our average working interest in this region is 75%. We have approximately 1.6 million gross (1.3 million net) acres under lease, which includes 305,000 acres in which we also own a royalty interest.

Reserves at December 31, 2013 were 7.5 Tcfe, an increase of 1.8 Tcfe, or 31%, from 2012 with drilling additions, a favorable reserve revision for performance, price and improved recovery were partially offset by production and downward revisions for proved undeveloped reserves no longer in our current five year development plan. Annual production increased 31% from 2012. During 2013, we spent $955.5 million in this region to drill 121 (117.8 net) development wells and 39 (35.2 net) exploratory wells, of which 159 (152.9 net) were productive. At December 31, 2013, the Appalachian region had an inventory of over 950 proven drilling locations and 600 proven recompletions. During the year, the Appalachian region drilled 115 proven locations, added 255 new proven drilling locations and deleted 214 proven drilling locations with reserves reclassified to unproved because of a slower pace of development activity beyond the five-year development horizon as required by the SEC’s reserve reporting requirements. During the year, the region achieved a 99.9% drilling success rate.

Marcellus Shale

We began operations in the Marcellus Shale in Pennsylvania during 2004. The Marcellus Shale is a unconventional reservoir, which produces natural gas, NGLs, crude oil and condensate. This has been our largest investment area over the last five years. We had over 586 proven drilling locations at December 31, 2013. Our 2013 production from the Marcellus Shale increased 39% from 2012. During 2013, we drilled 104 (101 net) development wells and 39 (35.2 net) exploratory wells, of which 142 (135.9 net) were successful. In 2014, we plan to drill 161.9 net wells. During 2013, we had approximately 8 drilling rigs in the field and expect to run an average of 9 rigs throughout 2014.

We have long-term agreements with third parties to provide gathering and processing services and infrastructure assets in the Marcellus Shale, which includes gathering and residue gas pipelines, compression, cryogenic processing and liquid fractionation. Pursuant to these agreements, in mid-2013, MarkWest Liberty Midstream, L.L.C. expanded its natural gas liquids infrastructure at one location to include new de-ethanization capacity at two of its complexes where we hold contracted capacity.

In 2011, we executed an ethane sales contract for the liquids-rich gas in southwestern Pennsylvania whereby a third party will transport ethane from the tailgate of the third-party processing and fractionation facilities to the international border for further delivery into Canada. Initial deliveries commenced in the second half 2013. Also in 2011, we entered into an agreement to transport ethane to the Gulf Coast where initial deliveries also commenced in late 2013.

In 2012, we entered into a fifteen year agreement to transport ethane and propane from the tailgate of a third-party processing plant to a terminal and dock facility near Philadelphia. Initial deliveries are expected to commence by the end of 2014. In the meantime, since 2012, we began transporting propane by rail and truck to the terminal and dock facility near Philadelphia for sale to domestic and international customers. Also in 2012, we executed a fifteen year ethane sales agreement from the same terminal near Philadelphia which is expected to begin in mid-2015.

Since 2008, we have entered into various firm transportation agreements to provide gas gathering and transportation from southwestern and northeastern Pennsylvania which, at December 31, 2013 provide commitments for 1.3 Bcfe per day. Some of our agreements, which extend to 2030, are contingent on pipeline modifications and/or construction. To support our drilling efforts and to control costs, we have contracts with drilling contractors to use two drilling rigs through 2015, and agreements for hydraulic fracturing services, including related equipment, material and labor, through 2015 in Pennsylvania.

Southwestern Region

The Southwestern region includes drilling, production and field operations in the Permian Basin of West Texas, the Texas Panhandle, as well as in the Anadarko Basin of western Oklahoma, Nemaha Uplift of northern Oklahoma and Kansas, the East Texas Basin and Mississippi. In the Southwestern region, we own 1,538 net producing wells, 96% of which we operate. Our average working interest is 80%. We have approximately 710,000 gross (508,000 net) acres under lease.

Total proved reserves in the Southwestern region decreased 97.0 Bcfe, or 13%, at December 31, 2013, when compared to year-end 2012. Drilling additions (162.1 Bcfe) and positive pricing revisions were offset by production, property sales (142.1 Bcfe) and negative performance revisions. Annual production volumes decreased 4% from 2012. During 2013, this region spent $237.3 million to drill 58.0 (55.1 net) development wells and 1.0 (0.5 net) exploratory wells, of which 58 (54.6 net) were productive. During the year, the region achieved a 98% drilling success rate. The region also drilled 6 service wells in 2013.

At December 31, 2013, the Southwestern region had a development inventory of over 125 proven drilling locations and over 200 proven recompletions. During the year, the Southwestern region drilled 19 proven locations, added 64 new proven locations and deleted 39 proven drilling locations primarily due to the sale of properties. Development projects include recompletions and infill drilling. These activities also include increasing reserves and production through cost control, upgrading lifting equipment, improving gathering systems and surface facilities, and performing reticulations and refracturing operations.

In December 2013, we announced our plans to offer for sale certain of our properties in the Permian Basin. These properties include approximately 90,000 (70,000 net) acres, almost all of which are held by production in Glasscock and Sterling Counties. The data room opened in January 2014 and we expect to receive bids in late February. However, the completion of the sale is dependent upon prospective buyer due diligence procedures and there can be no assurance the sale will be completed.

Producing Wells

The following table sets forth information relating to productive wells at December 31, 2013. We also own royalty interests in an additional 1,591 wells in which we do not own a working interest. If we own both a royalty and a working interest in a well, such interests are included in the table below. Wells are classified as natural gas or crude oil according to their predominant production stream. We do not have a significant number of dual completions.

	Total Wells		Average Working Interest
	Gross	Net	
Natural gas	9,387	7,023	75%
Crude oil	719	651	91%
Total	10,106	7,674	76%

The day-to-day operations of natural gas and oil properties are the responsibility of the operator designated under pooling or operating agreements. The operator supervises production, maintains production records, employs or contracts for field personnel and performs other functions. An operator receives reimbursement for direct expenses incurred in the performance of its duties as well as monthly per-well producing and drilling overhead reimbursement at rates customarily charged by unaffiliated third parties. The charges customarily vary with the depth and location of the well being operated.

Drilling Activity

The following table summarizes drilling activity for the past three years. Gross wells reflect the sum of all wells in which we own an interest. Net wells reflect the sum of our working interests in gross wells. As of December 31, 2013, we were in the process of drilling 14 (10.8 net) wells. In 2013, we also drilled 6 (6 net) service wells.

	2013		2012		2011	
	Gross	Net	Gross	Net	Gross	Net
Development wells						
Productive	178.0	171.9	226.0	202.3	262.0	236.5
Dry	1.0	1.0	–	–	–	–
Exploratory wells						
Productive	39.0	35.5	72.0	54.5	38.0	28.2
Dry	1.0	0.2	–	–	1.0	1.0
Total wells						
Productive	217.0	207.4	298.0	256.8	300.0	264.7
Dry	2.0	1.2	–	–	1.0	1.0
Total	219.0	208.6	298.0	256.8	301.0	265.7
Success ratio	99.1%	99.4%	100%	100%	99.7%	99.6%

Gross and Net Acreage

We own interests in developed and undeveloped natural gas and oil acreage. These ownership interests generally take the form of working interests in oil and natural gas leases that have varying terms. Developed acreage includes leased acreage that is allocated or assignable to producing wells or wells capable of production even though shallower or deeper horizons may not have been fully explored. Undeveloped acreage includes leased acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of natural gas or oil, regardless of whether or not the acreage contains proved reserves.

The following table sets forth certain information regarding the developed and undeveloped acreage in which we own a working interest as of December 31, 2013. Acreage related to royalty, overriding royalty and other similar interests is excluded from this summary:

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Illinois	—	—	13,332	7,312	13,332	7,312
Kansas	—	—	43,059	41,171	43,059	41,171
Louisiana	5,673	1,376	410	147	6,083	1,523
Mississippi	5,592	3,321	1,264	690	6,856	4,011
New York	—	—	3,900	1,423	3,900	1,423
Ohio	40	40	—	—	40	40
Oklahoma	184,457	126,840	212,432	152,110	396,889	278,950
Pennsylvania	514,141	476,476	509,247	437,702	1,023,388	914,178
Texas	163,062	120,617	80,338	54,623	243,400	175,240
Virginia	121,157	79,097	241,899	148,722	363,056	227,819
West Virginia	51,792	50,229	61,421	60,524	113,213	110,753
Wyoming	—	—	9,565	9,565	9,565	9,565
	1,045,914	857,996	1,176,867	913,989	2,222,781	1,771,985
Average working interest		82%		78%		80%

Undeveloped Acreage Expirations

The table below summarizes by year our undeveloped acreage scheduled to expire in the next five years.

	Acres		% of Total
As of December 31,	Gross	Net	Undeveloped
2014	217,568	179,624	26%
2015	106,102	96,603	14%
2016	156,439	110,682	16%
2017	32,309	29,478	4%
2018	38,994	27,122	4%

In most cases the drilling of a commercial well will hold acreage beyond the expiration date. We have leased acreage that is subject to lease expiration if initial wells are not drilled within a specified period, generally between three to five years. However, we have in the past and expect in the future, to be able to extend the lease terms of some of these leases and exchange or sell some of these leases with other companies. The expirations included in the table above do not take into account the fact that we may be able to extend the lease terms. We do not expect to lose significant lease acreage because of failure to drill due to inadequate capital, equipment or personnel. However, based on our evaluation of prospective economics, we have allowed acreage to expire from time to time and expect to allow additional acreage to expire in the future.

Title to Properties

We believe that we have satisfactory title to all of our producing properties in accordance with generally accepted industry standards. As is customary in the industry, in the case of undeveloped properties, often minimal investigation of record title is made at the time of lease acquisition. Investigations are made before the consummation of an acquisition of producing properties and before commencement of drilling operations on undeveloped properties. Individual properties may be subject to burdens that we believe do not materially interfere with the use or affect the value of the properties. Burdens on properties may include:

- customary royalty interests;
- liens incident to operating agreements and for current taxes;
- obligations or duties under applicable laws;
- development obligations under oil and gas leases; or
- net profit interests.

Delivery Commitments

For a discussion of our delivery commitments, see “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations-*Delivery Commitments*.”

Employees

As of January 1, 2014, we had 867 full-time employees, 320 of whom were field personnel. All full-time employees are eligible to receive equity awards approved by the compensation committee of the board of directors. No employees are currently covered by a labor union or other collective bargaining arrangement. We believe that the relationship with our employees is excellent. We regularly use independent consultants and contractors to perform various professional services, particularly in the areas of drilling, completion, field services, on-site production services and certain accounting functions.

Competition

Intense competition exists in all sectors of the oil and gas industry and in particular, we encounter substantial competition in developing and acquiring natural gas and oil properties, securing and retaining personnel, conducting drilling and field operations and marketing production. Competitors in exploration, development, acquisitions and production include the major oil and gas companies as well as numerous independent oil and gas companies, individual proprietors and others. Although our sizable acreage position and core area concentration provide some competitive advantages, many competitors have financial and other resources substantially exceeding ours. Therefore, competitors may be able to pay more for desirable leases and evaluate, bid for and purchase a greater number of properties or prospects than our financial or personnel resources allow. Our ability to replace and expand our reserve base depends on our ability to attract and retain quality personnel and identify and acquire suitable producing properties and prospects for future drilling. For more information, see “Item 1A. Risk Factors.”

Marketing and Customers

We market the majority of our natural gas, NGLs, crude oil and condensate production from the properties we operate for our interest, and that of the other working interest owners. We pay our royalty owners from the sales attributable to our working interest. Natural gas, NGLs and oil purchasers are selected on the basis of price, credit quality and service reliability. For a summary of purchasers of our natural gas, NGLs and oil production that accounted for 10% or more of consolidated revenue, see Note 16 to our consolidated financial statements. Because alternative purchasers of natural gas and oil are usually readily available, we believe that the loss of any of these purchasers would not have a material adverse effect on our operations. Production from our properties is marketed using methods that are consistent with industry practice. Sales prices for natural gas, NGLs and oil production are negotiated based on factors normally considered in the industry, such as index or spot price, distance from the well to the pipeline, commodity quality and prevailing supply and demand conditions. Our natural gas production is sold to utilities, marketing and mid-stream companies and industrial users. Our NGLs production is typically sold to natural gas processors or users of NGLs. Our oil and condensate production is sold to crude oil processors, transporters and refining and marketing companies in the area. Market volatility due to fluctuating weather conditions, international political developments, overall energy supply and demand, economic growth rates and other factors in the United States and worldwide have had, and will continue to have, a significant effect on energy prices.

We enter into derivative transactions with unaffiliated third parties for a varying portion of our production to achieve more predictable cash flows and to reduce our exposure to short-term fluctuations in natural gas, NGLs and oil prices. For a more detailed discussion, see “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations” and “Item 7A. Quantitative and Qualitative Disclosures about Market Risk.”

We incur gathering and transportation expense to move our production from the wellhead and tanks to purchaser specified delivery points. These expenses vary based on volume, distance shipped and the fee charged by the third-party gatherers and transporters. In the Southwestern region, our production is transported primarily through purchaser-owned or third-party trucks, field gathering systems and transmission pipelines. Transportation capacity on these gathering and transportation systems and pipelines is occasionally constrained. In Appalachia, we own some gas gathering and transportation pipelines, which transport a portion of our Appalachian production and third-party production to transmission lines, directly to end-users and interstate pipelines. Our remaining Appalachian production is transported on third-party pipelines on which, in most cases, we hold long-term contractual capacity. We attempt to balance sales, storage and transportation positions, which can include purchase of commodities from third parties for resale, to satisfy transportation commitments.

We have not experienced significant difficulty to date in finding a market for all of our production as it becomes available or in transporting our production to those markets; however, there is no assurance that we will always be able to transport and market all of our production or obtain favorable prices.

We have entered into three ethane agreements to sell or transport ethane from our Marcellus Shale area. Initial deliveries commenced in late 2013 on two of these agreements. The remaining agreement is contingent on pipeline modifications and/or construction with operations expected to begin in mid-2015. For more information, see "Item 1A. Risk Factors – *Our business depends on natural gas and oil transportation and NGLs processing facilities, most of which are owned by others and depends on our ability to contract with those parties."*

Seasonal Nature of Business

Generally, but not always, the demand for natural gas and propane decreases during the summer months and increases during the winter months. Seasonal anomalies such as mild winters or hot summers sometimes lessen this fluctuation. In addition, pipelines, utilities, local distribution companies and industrial end-users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer. This can also lessen the seasonality of demand.

Governmental Regulation

Enterprises that sell securities in public markets are subject to regulatory oversight by federal agencies such as the SEC and the NYSE, a private stock exchange which requires us to comply with listing requirements in order to keep our common stock listed there. This regulatory oversight imposes on us the responsibility for establishing and maintaining disclosure controls and procedures and internal controls over financial reporting, and ensuring that the financial statements and other information included in submissions to the SEC do not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made in such submissions not misleading. Failure to comply with the listing rules and regulations of the SEC could subject us to litigation from public or private plaintiffs. Failure to comply with the rules of the NYSE could result in the de-listing of our common stock, which could have an adverse effect on the market price of our common stock. Compliance with some of these rules and regulations is costly, and regulations are subject to change or reinterpretation.

Exploration and development and the production and sale of oil and gas are subject to extensive federal, state and local regulations. An overview of these regulations is set forth below. We believe we are in substantial compliance with currently applicable laws and regulations and the continued substantial compliance with existing requirements will not have a material adverse effect on our financial position, cash flows or results of operations. However, current regulatory requirements may change, currently unforeseen environmental incidents may occur or past non-compliance with environmental laws or regulations may be discovered. See "Item 1A. Risk Factors – *The natural gas and oil industry is subject to extensive regulation."* We do not believe we are affected differently by these regulations than others in the industry.

General Overview. Our oil and gas operations are subject to various federal, state, tribal and local laws and regulations. Generally speaking, these regulations relate to matters that include, but are not limited to:

- leases;
- acquisition of seismic data;
- location of wells, pads, roads, impoundments, facilities, rights of way;
- size of drilling and spacing units or proration units;
- number of wells that may be drilled in a unit;
- unitization or pooling of oil and gas properties;
- drilling, casing and completion of wells;
- issuance of permits in connection with exploration, drilling and production;
- well production, maintenance, operations and security;
- spill prevention plans;
- emissions permitting or limitations;
- protection of endangered species;
- use, transportation, storage and disposal of fluids and materials incidental to oil and gas operations;
- surface usage and the restoration of properties upon which wells have been drilled;
- calculation and disbursement of royalty payments and production taxes;

- plugging and abandoning of wells; and
- transportation of production.

In August 2005, Congress enacted the Energy Policy Act of 2005 ("EPAct 2005"). Among other matters, the EPAct 2005 amends the Natural Gas Act ("NGA"), to make it unlawful for "any entity," including otherwise non-jurisdictional producers such as Range, to use any deceptive or manipulative device or contrivance in connection with the purchase or sale of natural gas or the purchase or sale of transportation services subject to regulation by the FERC, in contravention of rules prescribed by the FERC. On January 20, 2006, the FERC issued rules implementing this provision. The rules make it unlawful in connection with the purchase or sale of natural gas subject to the jurisdiction of the FERC, or the purchase or sale of transportation services subject to the jurisdiction of the FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; to make any untrue statement of material fact or omit any such statement necessary to make the statements not misleading; or to engage in any act or practice that operates as a fraud or deceit upon any person. EPAct 2005 also gives the FERC authority to impose civil penalties for violations of the NGA up to $1,000,000 per day per violation. The new anti-manipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sale or gathering, but does apply to activities or otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to the FERC's jurisdiction which includes the reporting requirements under Order No. 704, described below. It therefore reflects a significant expansion of the FERC's enforcement authority. Range has not been affected differently than any other producer of natural gas by this act. Failure to comply with applicable laws and regulations can result in substantial penalties. The regulatory burden on the industry increases the cost of doing business and affects profitability. Although we believe we are in substantial compliance with all applicable laws and regulations, such laws and regulations are frequently amended or reinterpreted. Therefore, we are unable to predict the future costs or impact of compliance. Additional proposals and proceedings that affect the oil and natural gas industry are regularly considered by Congress, the states, the FERC, and the courts. We cannot predict when or whether any such proposals may become effective.

On December 26, 2007, the FERC issued a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing ("Order 704"). Under Order 704, wholesale buyers and sellers of more than 2.2 million MMBtus of physical natural gas in the previous calendar year, including natural gas gatherers and marketers, are now required to report, on May 1 of each year beginning in 2009, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to, or may contribute to the formation of price indices. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order 704. Order 704 also requires market participants to indicate whether they report prices to any index publishers, and if so, whether their reporting complies with the FERC's policy statement on price reporting. On November 15, 2012, in docket No. RM13-1, the FERC issued a Notice of Inquiry seeking comments on whether requiring all market participants engaged in sales of wholesale physical natural gas in interstate commerce to report quarterly to the Commission every natural gas transaction within the Commission's NGA jurisdiction that entails physical delivery for the next day or for the next month in order to improve natural gas market transparency. We cannot predict when or whether any such proposals may become effective.

Environmental and Occupational Health and Safety Matters

Our operations are subject to numerous stringent federal, state and local laws and regulations governing occupational health and safety, the discharge of materials into the environment or otherwise relating to environmental protection, some of which carry substantial administrative, civil and criminal penalties for failure to comply. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling, production and transporting through pipelines, govern the sourcing and disposal of water used in the drilling and completion process, limit or prohibit drilling activities on certain lands lying within wilderness, wetlands, frontier and other protected areas, require some form of remedial action to prevent or mitigate pollution from existing and former operations such as plugging abandoned wells or closing earthen impoundments and impose substantial liabilities for pollution resulting from operations or failure to comply with regulatory filings. These laws and regulations also may restrict the rate of production. Moreover, changes in environmental laws and regulations often occur, and any changes that result in more stringent and costly well construction, drilling, water management or completion activities or more restrictive waste handling storage, transport, disposal or cleanup requirements for any substances used or produced in our operations could materially adversely affect our operations and financial position, as well as those of the oil and natural gas industry in general.

The Comprehensive Environmental Response, Compensation and Liability Act, as amended ("CERCLA"), also known as the "Superfund" law, and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons who are considered to be responsible for the release of a "hazardous substance" into the environment. These persons may include owners or operators of the disposal site or sites where the hazardous substance release occurred and companies that disposed of or arranged for the disposal of the hazardous substances at the site where the release occurred. Under CERCLA, all of these persons may be subject to joint and several liabilities 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, pursuant to environmental statutes, common law or both, to file claims for personal injury and property damages allegedly caused by the release of hazardous substances or other pollutants into the environment. Although petroleum, including crude oil and natural gas, is not a "hazardous substance" under CERCLA, at least two courts have ruled that certain wastes associated with the production of crude oil may be classified as "hazardous substances" under CERCLA and that releases of such wastes may therefore give rise to liability under CERCLA. While we generate materials in the course of our operations that may be regulated as hazardous substances, we have not received notification that we may be potentially responsible for cleanup costs under CERCLA or comparable state laws. Other state laws regulate the disposal of oil and natural gas wastes, and new state and federal regulatory initiatives that could have a significant adverse impact on us may periodically be proposed and enacted.

We also may incur liability under the Resource Conservation and Recovery Act, as amended ("RCRA") and comparable state laws, which impose requirements related to the handling and disposal of non-hazardous solid wastes and hazardous wastes. Drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil, natural gas or geothermal energy are currently regulated by the United States Environmental Protection Agency ("EPA") and state agencies under RCRA's less stringent non-hazardous solid waste provisions. It is possible that these solid wastes could in the future be re-classified as hazardous wastes, whether by amendment of RCRA or adoption of new laws, which could significantly increase our costs to manage and dispose of such wastes. Moreover, ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes and waste compressor oils, may be regulated as hazardous wastes. Although the costs of managing wastes classified as hazardous waste may be significant, we do not expect to experience more burdensome costs than similarly situated companies in our industry.

We currently own or lease, and have in the past owned or leased, properties that for many years have been used for the exploration and production of crude oil and natural gas. Petroleum hydrocarbons or wastes may have been disposed of or released on or under the properties owned or leased by us, or on or under other locations where such materials have been taken for disposal. In addition, some of these properties have been operated by third parties whose treatment and disposal or release of petroleum hydrocarbons and wastes was not under our control. These properties and the materials disposed or released on them may be subject to CERCLA, RCRA and comparable state laws and regulations. Under such laws and regulations, we could be required to remove or remediate previously disposed wastes or property contamination, or to perform remedial activities to prevent future contamination.

The Federal Water Pollution Control Act, as amended, and comparable state laws impose restrictions and strict controls regarding the discharge of pollutants, including produced waters and other oil and natural gas wastes, into federal and state waters. 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 wetlands, unless authorized by permit. These laws and any implementing regulations provide for administrative, civil and criminal penalties for any unauthorized discharges of oil and other substances in reportable quantities and may impose substantial potential liability for the costs of removal, remediation and damages. Pursuant to these laws and regulations, we may be required to obtain and maintain approvals or permits for the discharge of wastewater or storm water and are required to develop and implement spill prevention, control and countermeasure plans, also referred to as "SPCC plans," in connection with on-site storage of greater than threshold quantities of oil. We regularly review our natural gas and oil properties to determine the need for new or updated SPCC plans and, where necessary, we will be developing or upgrading such plans, the costs of which are not expected to be substantial.

The Oil Pollution Act of 1990, as amended ("OPA") contains numerous requirements relating to the prevention of and response to oil spills into waters of the United States. The OPA subjects owners of facilities to strict, joint and several liability for all containment and cleanup costs and certain other damages arising from an oil spill, including, but not limited to, the costs of responding to a release of oil to surface waters. While we believe we have been in substantial compliance with OPA, noncompliance could result in varying civil and criminal penalties and liabilities.

The Clean Air Act, as amended, and comparable state laws restrict the emission of air pollutants from many sources, including compressor stations. These laws and any implementing regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions, impose stringent air permit requirements, or use specific equipment or technologies to control emissions. We may be required to incur certain capital expenditures in the next few years for air pollution control equipment in connection with maintaining or obtaining operating permits and approvals for emissions of pollutants. For example, in 2012, the EPA published final rules under the Clean Air Act that subject oil and natural gas production, processing, transmission and storage operations to regulation under the New Source Performance Standards ("NSPS") and National Emission Standards for Hazardous Air Pollutants ("NESHAP") programs. With regards to production activities, these final rules require, among other things, the reduction of volatile organic compound emissions from three subcategories of fractured and refractured gas wells for which well completion operations are conducted: wildcat (exploratory) and delineation gas wells; low reservoir pressure non-wildcat and non-delineation gas wells; and all "other" fractured and refractured gas wells. All three subcategories of wells must route flow back emissions to a gathering line or be captured and combusted using a combustion device such as a flare. However, the "other" wells must use reduced emission completions, also known as "green completions," with or without combustion devices, after January 1, 2015. These regulations also establish specific requirements regarding emissions from production-related wet seal and reciprocating compressors and from pneumatic controllers and storage vessels, effective as early as

October 15, 2013. Our flow back operations in many of our divisions already meet these requirements by capturing and/or flaring gas emissions and, in many of our divisions, we have also been utilizing vapor recovery units or enclosed burner units on storage vessels which reduce emissions below published levels. We do not believe continuing to implement such requirements will have a material adverse effect on our operations as compared to other similarly situated operators.

In 2009, the EPA published its findings that emissions of carbon dioxide, methane and other greenhouse gases ("GHGs") present a danger to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the Earth's atmosphere and other climatic conditions. Based on these findings, the EPA adopted regulations under the existing Clean Air Act establishing Title V and Prevention of Significant Deterioration ("PSD") permitting requirements for large sources of GHG's that are potential major sources of GHG emissions. We could become subject to these Title V and PSD permitting requirements and be required to install "best available control technology" to limit emissions of GHG's from any new or significantly modified facilities that we may seek to construct in the future if such facilities emitted volumes of GHGs in excess of threshold permitting levels. The EPA has also adopted rules requiring the reporting of GHG emissions from specified emission sources in the United States on an annual basis, including certain oil and natural gas production facilities, which include certain of our facilities. We are monitoring some of the GHG emissions from our operations and believe that our monitoring activities are in substantial compliance with applicable reporting obligations.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of federal climate legislation in the U.S., a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting those GHGs. Moreover, if Congress undertakes comprehensive tax reform in the coming year, it is possible that such reform include a carbon tax, which could impose additional direct costs on operations and reduce demand for refined products.

Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emission allowances or comply with new regulatory or reporting requirements including the imposition of a carbon tax. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for oil and natural gas, which could reduce the demand for the oil and natural gas that we produce. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts and floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations.

Hydraulic fracturing, which has been used by the industry for over 60 years, is an important and common practice used to stimulate production of natural gas and/or oil from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand and chemicals under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate production. We routinely apply hydraulic fracturing techniques as part of our operations. This process is typically regulated by state oil and natural gas commissions but the EPA has asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel fuels under the federal Safe Drinking Water Act and issued revised permitting guidance in February 2014 addressing the performance of such activities. Also, in November 2011, the EPA announced its intent to develop and issue regulations under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing and in the Semi-Annual Regulatory Agenda published on July 3, 2013, the agency continued to project the issuance of an Advance Notice of Proposed Rulemaking that would seek public input on the design and scope of such disclosure regulations. Moreover, from time to time, Congress has considered adopting legislation intended to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process. In addition to any actions by Congress, certain states in which we operate, including Pennsylvania, Texas and West Virginia have adopted, and other states are considering adopting, regulations imposing or that could impose new or more stringent permitting, public disclosure, or well-construction requirements on hydraulic fracturing operations. Local governments also may seek to adopt ordinances within their jurisdiction regulating the time, place or manner of drilling activities in general or hydraulic fracturing activities in particular. We believe that we follow applicable standard industry practices and legal requirements for groundwater protection in our hydraulic fracturing activities. Nevertheless, if new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process is adopted in areas where we currently or in the future plan to operate, we may incur additional, more significant, costs to comply with such requirements and also could become subject to additional permitting requirements and experience added delays or curtailment in the pursuit of exploration, development, or production activities.

In addition, certain government reviews have been conducted or are underway that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with a final draft report drawing conclusions about the potential impacts of hydraulic fracturing on drinking water resources expected to be available for public comment and peer review in 2014. Moreover, the EPA is developing effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities that it plans to propose as standards in 2014. Also, in May 2013, the federal Bureau of Land Management ("BLM") published a supplemental notice of proposed rulemaking governing hydraulic fracturing on federal and Indian oil and gas leases that would require public disclosure of chemicals used in hydraulic fracturing, confirmation that wells used in fracturing operations meet appropriate construction standards, and development of appropriate plans for managing flowback water returning to the surface. These existing or any future studies, depending on any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the federal Safe Drinking Act or other regulatory mechanisms.

We believe that our hydraulic fracturing activities follow applicable industry practices and legal requirements for groundwater protection and that our fracturing operations have not resulted in material environmental liabilities. We do not have insurance policies in effect that are intended to provide coverage for losses solely related to hydraulic fracturing operations; however, we believe our existing insurance policies would cover third-party bodily injury and property damage caused by hydraulic fracturing including sudden and accidental pollution coverage.

Oil and natural gas exploration, development and production activities on federal lands, including Indian lands and lands administered by the BLM, are subject to the National Environmental Policy Act, as amended (“NEPA”). NEPA requires federal agencies, including the BLM, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. Currently, we have minimal exploration and production activities on federal lands. However, for those current activities as well as for future or proposed exploration and development plans on federal lands, governmental permits or authorizations that are subject to the requirements of NEPA are required. This process has the potential to delay or limit, or increase the cost of, the development of oil and natural gas projects. Authorizations under NEPA are also subject to protest, appeal or litigation, any or all of which may delay or halt projects.

The federal Endangered Species Act, as amended, restricts activities that may affect endangered and threatened species or their habitats. If endangered species are located in an area where we wish to conduct seismic surveys, development activities or abandonment operations, the work could be prohibited or delayed or expensive mitigation may be required. Moreover, the designation of previously unidentified endangered or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas. For example, as a result of a settlement approved by the U.S. District Court for the District of Columbia in September 2011, the U.S. Fish and Wildlife Service is required to make a determination on the listing of numerous species as endangered or threatened under the Endangered Species Act prior to the completion of the agency’s 2017 fiscal year. The designation of previously unprotected species in areas where we operate as threatened or endangered could cause us to incur increased costs arising from species protection measures or could result in limitations on our exploration and production activities that could have an adverse impact on our ability to develop and produce our reserves.

The Migratory Bird Treaty Act implements various treaties and conventions between the United States and certain other nations for the protection of migratory birds. In accordance with this law, the taking, killing or possessing of migratory birds covered under this act is unlawful without a permit. If there is the potential to adversely affect migratory birds as a result of our operations, we may be required to obtain necessary permits to conduct those operations, which may result in specified operating restrictions on a temporary, seasonal, or permanent basis in affected areas and an adverse impact on our ability to develop and produce our reserves.

In summary, we believe we are in substantial compliance with currently applicable environmental laws and regulations. Although we have not experienced any material adverse effect from compliance with environmental requirements, there is no assurance that this will continue. We did not have any material capital or other non-recurring expenditures in connection with complying with environmental laws or environmental remediation matters in 2013, nor do we anticipate that such expenditures will be material in 2014. However, we regularly have expenditures to comply with environmental laws and those costs continue to increase as our operations expand.

We are also subject to the requirements of the federal Occupational Safety and Health Act, as amended (“OSHA”), and comparable state laws that regulate the protection of the health and safety of employees. In addition, OSHA’s hazard communication standard requires that information be maintained about hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We believe that our operations are in substantial compliance with the OSHA requirements.

ITEM 1A. RISK FACTORS

We are subject to various risks and uncertainties in the course of our business. The following summarizes the known material risks and uncertainties, which may adversely affect our business, financial condition or results of operations. These risks are not the only risks we face. Our business could also be impacted by additional risks and uncertainties not currently known to us or that we currently deem to be immaterial.

Risks Related to Our Business

Volatility of natural gas, NGLs and oil prices significantly affects our cash flow and capital resources and could hamper our ability to produce natural gas, NGLs, crude oil and condensate economically

Natural gas, NGLs and oil prices are volatile, and a decline in prices adversely affects our profitability and financial condition. The oil and gas industry is typically cyclical, and we expect the volatility to continue. Over the past four years, the average NYMEX monthly settlement price of natural gas has been as high as $5.27 per mcf and as low as $2.04 mcf. During that same time frame, the average NYMEX monthly oil settlement price was as high as $108.15 per barrel and as low as $68.01 per barrel. As of the end of January 2014, natural gas was at $5.56 per mcf and oil was at $94.99 per barrel. Natural gas prices are likely to affect us more than oil prices because approximately 69% of our December 31, 2013 proved reserves are natural gas. Long-term supply and demand for natural gas, NGLs and oil is uncertain and subject to a myriad of factors such as:

- the domestic and foreign supply of natural gas, NGLs and oil;
- the price, availability and demand for alternative fuels and sources of energy;
- weather conditions;
- the level of consumer demand for natural gas, NGLs and oil;
- the price and level of foreign imports;
- U.S. domestic and worldwide economic conditions;
- the availability, proximity and capacity of transportation facilities and processing facilities;
- the effect of worldwide energy conservation efforts;
- political conditions in natural gas and oil producing regions; and
- domestic (federal, state and local) and foreign governmental regulations and taxes.

Lower natural gas, NGLs and oil prices may not only decrease our revenues on a per unit basis but also may reduce the amount of natural gas, NGLs and oil that we can economically produce. A reduction in production could result in a shortfall in expected cash flows and require a reduction in capital spending or require additional borrowing. Without the ability to fund capital expenditures, we would be unable to replace reserves which would negatively affect our future rate of growth.

Producing natural gas, NGLs and oil may involve unprofitable efforts. As of December 31, 2013, the relationship between the price of oil and the price of natural gas continues to be at an unprecedented spread. Normally, natural gas liquids production is a by-product of natural gas production. Due to the current differences in prices, we and other producers may choose to sell natural gas at below cost, or otherwise dispose of natural gas to allow for the profitable sale of only NGLs and condensate. Over the past three years, the average Mont Belvieu NGL composite has been as high as $1.31 per gallon and as low as $0.70 per gallon.

Information concerning our reserves and future net cash flow estimates is uncertain

There are numerous uncertainties inherent in estimating quantities of proved natural gas and oil reserves and their values, including many factors beyond our control. Estimates of proved reserves are by their nature uncertain. Although we believe these estimates are reasonable, actual production, revenues and costs to develop will likely vary from estimates and these variances could be material.

Reserve estimation is a subjective process that involves estimating volumes to be recovered from underground accumulations of natural gas and oil that cannot be directly measured. As a result, different petroleum engineers, each using industry-accepted geologic and engineering practices and scientific methods, may calculate different estimates of reserves and future net cash flows based on the same available data. Because of the subjective nature of natural gas, NGLs and oil reserve estimates, each of the following items may differ materially from the amounts or other factors estimated:

- the amount and timing of natural gas, NGLs and oil production;
- the revenues and costs associated with that production;

- the amount and timing of future development expenditures; and
- future commodity prices.

The discounted future net cash flows from our proved reserves included in this report should not be considered as the market value of the reserves attributable to our properties. As required by generally accepted accounting principles, the estimated discounted future net revenues from our proved reserves are based on a twelve month average price (first day of the month) while cost estimates are based on current year-end economic conditions. Actual future prices and costs may be materially higher or lower. In addition, the ten percent discount factor that is required to be used to calculate discounted future net revenues for reporting purposes under generally accepted accounting principles is not necessarily the most appropriate discount factor based on the cost of capital in effect from time to time and risks associated with our business and the oil and gas industry in general.

If natural gas, NGLs and oil prices decrease or drilling efforts are unsuccessful, we may be required to record writedowns of our natural gas and oil properties

In the past we have been required to write down the carrying value of certain of our natural gas and oil properties, and there is a risk that we will be required to take additional writedowns in the future. Writedowns may occur when natural gas and oil prices are low, or if we have downward adjustments to our estimated proved reserves, increases in our estimates of operating or development costs, deterioration in our drilling results or mechanical problems with wells where the cost to redrill or repair is not supported by the expected economics.

Accounting rules require that the carrying value of natural gas and oil properties be periodically reviewed for possible impairment. Impairment is recognized for the excess of book value over fair value when the book value of a proven property is greater than the expected undiscounted future net cash flows from that property and on acreage when conditions indicate the carrying value is not recoverable. We may be required to write down the carrying value of a property based on natural gas and oil prices at the time of the impairment review, or as a result of continuing evaluation of drilling results, production data, economics, divestiture activity, and other factors. While an impairment charge reflects our long-term ability to recover an investment, it does not impact cash or cash flow from operating activities, but it does reduce our reported earnings and increases our leverage ratios.

Significant capital expenditures are required to replace our reserves

Our exploration, development and acquisition activities require substantial capital expenditures. Historically, we have funded our capital expenditures through a combination of cash flow from operations, our bank credit facility and debt and equity issuances. We have also engaged in asset monetization transactions. Future cash flows are subject to a number of variables, such as the level of production from existing wells, prices of natural gas, NGLs and oil and our success in developing and producing new reserves. If our access to capital were limited due to various factors, which could include a decrease in revenues due to lower natural gas, NGLs and oil prices or decreased production or deterioration of the credit and capital markets, we would have a reduced ability to replace our reserves. We may not be able to incur additional bank debt, issue debt or equity, engage in asset monetization or access other methods of financing on an economic basis to meet our reserve replacement requirements.

The amount available for borrowing under our bank credit facility is subject to a borrowing base, which is determined by our lenders, at their discretion, taking into account our estimated proved reserves and is subject to periodic redeterminations based on pricing models determined by the lenders at such time. Declines in natural gas, NGLs and oil prices adversely impact the value of our estimated proved reserves and, in turn, the market values used by our lenders to determine our borrowing base. If commodity prices (particularly natural gas prices) decline, it will have similar adverse effects on our reserves and borrowing base.

Our future success depends on our ability to replace reserves that we produce

Because the rate of production from natural gas and oil properties generally declines as reserves are depleted, our future success depends upon our ability to economically find or acquire and produce additional natural gas, NGLs and oil reserves. Except to the extent that we acquire additional properties containing proved reserves, conduct successful exploration and development activities or, through engineering studies, identify additional behind-pipe zones or secondary recovery reserves, our proved reserves will decline as reserves are produced. Future natural gas, NGLs and oil production, therefore, is highly dependent upon our level of success in acquiring or finding additional reserves that are economically recoverable. We cannot assure you that we will be able to find or acquire and develop additional reserves at an acceptable cost.

We acquire significant amounts of unproved property to further our development efforts. Development and exploratory drilling and production activities are subject to many risks, including the risk that no commercially productive reservoirs will be discovered. We acquire both producing and unproved properties as well as lease undeveloped acreage that we believe will enhance growth potential and increase our earnings over time. However, we cannot assure you that all prospects will be economically viable or that we will not abandon our initial investments. Additionally, there can be no assurance that 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 or that we will recover all or any portion of our investment in such unproved property or wells.

Drilling is an uncertain and costly activity

The cost of drilling, completing, and operating a well is often uncertain, and many factors can adversely affect the economics of a well. Our efforts will be uneconomical if we drill dry holes or wells that are productive but do not produce enough natural gas, NGLs and oil to be commercially viable after drilling, operating and other costs. Furthermore, our drilling and producing operations may be curtailed, delayed, or canceled as a result of a variety of factors, including:

- high costs, shortages or delivery delays of drilling rigs, equipment, water for hydraulic fracturing services, labor, or other services;
- unexpected operational events and drilling conditions;
- reductions in natural gas, NGLs and oil prices;
- limitations in the market for natural gas, NGLs and oil;
- adverse weather conditions;
- facility or equipment malfunctions;
- equipment failures or accidents;
- title problems;
- pipe or cement failures;
- compliance with, or changes in, environmental, tax and other governmental requirements;
- environmental hazards, such as natural gas leaks, oil spills, pipeline ruptures, and discharges of toxic gases;
- lost or damaged oilfield drilling and service tools;
- unusual or unexpected geological formations;
- loss of drilling fluid circulation;
- pressure or irregularities in formations;
- fires;
- natural disasters;
- surface craterings and explosions; and
- uncontrollable flows of oil, natural gas or well fluids.

If any of these factors were to occur with respect to a particular field, we could lose all or a part of our investment in the field, or we could fail to realize the expected benefits from the field, either of which could materially and adversely affect our revenue and profitability.

Our producing properties are concentrated in the Appalachian Basin, making us vulnerable to risks associated with operating in one major geographic area

Our producing properties are geographically concentrated in the Appalachian Basin in Pennsylvania, Virginia and West Virginia. At December 31, 2013, 92% of our total estimated proved reserves were attributable to properties located in this area. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, state politics, processing or transportation capacity constraints, market limitations, water shortages or other drought related conditions or interruption of the processing or transportation of crude oil, condensate, natural gas or NGLs.

New technologies may cause our current exploration and drilling methods to become obsolete

There have been rapid and significant advancements in technology in the natural gas and oil industry, including the introduction of new products and services using new technologies. As competitors use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement new technologies at a substantial increase in cost. Further, competitors may obtain patents which might prevent us from implementing new technologies. In addition, competitors may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we can. One or more of the technologies that we currently use or that we may implement in the future may become obsolete. We cannot be certain that we will be able to implement technologies on a timely basis or at a cost that is acceptable to us. If we are unable to maintain technological advancements consistent with industry standards, our operations and financial condition may be adversely affected.

Our indebtedness could limit our ability to successfully operate our business

We are leveraged and our exploration and development program will require substantial capital resources depending on the level of drilling and the expected cost of services. Our existing operations will also require ongoing capital expenditures. In addition, if we decide to pursue additional acquisitions, our capital expenditures will increase, both to complete such acquisitions and to explore and develop any newly acquired properties.

The degree to which we are leveraged could have other important consequences, including the following:

- we may be required to dedicate a substantial portion of our cash flows from operations to the payment of our indebtedness, reducing the funds available for our operations;
- a portion of our borrowings are at variable rates of interest, making us vulnerable to increases in interest rates;
- we may be more highly leveraged than some of our competitors, which could place us at a competitive disadvantage;
- our degree of leverage may make us more vulnerable to a downturn in our business or the general economy;
- we are subject to numerous financial and other restrictive covenants contained in our existing credit agreements the breach of which could materially and adversely impact our financial performance;
- our debt level could limit our flexibility to grow the business and in planning for, or reacting to, changes in our business and the industry in which we operate; and
- we may have difficulties borrowing money in the future.

Despite our current levels of indebtedness, we still may be able to incur substantially more debt. This could further increase the risks described above. In addition to those risks above, we may not be able to obtain funding on acceptable terms.

Any failure to meet our debt obligations could harm our business, financial condition and results of operations

If our cash flow and capital resources are insufficient to fund our debt obligations, we may be forced to sell assets, seek additional equity or restructure our debt. In addition, any failure to make scheduled payments of interest and principal on our outstanding indebtedness would likely result in a reduction of our credit rating, which could harm our ability to incur additional indebtedness on acceptable terms. Our cash flow and capital resources may be insufficient for payment of interest on and principal of our debt in the future and any such alternative measures may be unsuccessful or may not permit us to meet scheduled debt service obligations, which could cause us to default on our obligations and impair our liquidity.

We are subject to financing and interest rate exposure risks

Our business and operating results can be harmed by factors such as the availability, terms of and cost of capital, increases in interest rates or a reduction in our credit rating. These changes could cause our cost of doing business to increase, limit our ability to pursue acquisition opportunities, reduce cash flow used for drilling and place us at a competitive disadvantage. For example, at December 31, 2013, approximately 84% of our debt is at fixed interest rates with the remaining 16% subject to variable interest rates.

Disruptions or volatility in the global finance markets may lead to a contraction in credit availability impacting our ability to finance our operations. We require continued access to capital. A significant reduction in cash flows from operations or the availability of credit could materially and adversely affect our ability to achieve our planned growth and operating results. We are exposed to some credit risk related to our bank credit facility to the extent that one or more of our lenders may be unable to provide necessary funding to us under our existing revolving line of credit if it experiences liquidity problems.

A worldwide financial downturn or negative credit market conditions may have lasting effects on our liquidity, business and financial condition that we cannot predict

Liquidity is essential to our business. Our liquidity could be substantially negatively affected by an inability to obtain capital in the long-term or short-term debt capital markets or equity capital markets or an inability to access bank financing. A prolonged credit crisis or turmoil in the global financial system, could materially affect our liquidity, business and financial condition. These conditions have adversely impacted financial markets previously and created substantial volatility and uncertainty, and could to do so again, with the related negative impact on global economic activity and the financial markets. Negative credit market conditions could materially affect our liquidity and may inhibit our lenders from fully funding our bank credit facility or cause them to make the terms of our bank credit facility costlier and more restrictive. We are subject to semiannual reviews, as well as unscheduled reviews, of our borrowing base under our bank credit facility, and we do not know the results of future redeterminations or the effect of then-current oil and natural gas prices on that process. A weak economic environment could also adversely affect the collectability of our trade receivables or performance by our suppliers and cause our commodity derivative arrangements to be ineffective if our counterparties are unable to perform their obligations or seek bankruptcy protection. Additionally, negative economic conditions could lead to reduced demand for natural gas, NGLs and oil or lower prices for natural gas and oil, which could have a negative impact on our revenues.

Derivative transactions may limit our potential gains and involve other risks

To manage our exposure to price risk, we currently and may in the future enter into derivative arrangements, utilizing commodity derivatives with respect to a portion of our future production. The goal of these hedges is to lock in prices so as to limit volatility and increase the predictability of cash flow. These transactions limit our potential gains if natural gas, NGLs and oil prices rise above the price established by the hedge.

In addition, derivative transactions may expose us to the risk of financial loss in certain circumstances, including instances in which:

- our production is less than expected;
- the counterparties to our futures contracts fail to perform on their contract obligations; or
- an event materially impacts natural gas, NGLs or oil prices or the relationship between the hedged price index and the natural gas or oil sales price.

We cannot assure you that any derivative transaction we may enter into will adequately protect us from declines in the prices of natural gas, NGLs or oil. On the other hand, where we choose not to engage in derivative transactions in the future, we may be more adversely affected by changes in natural gas, NGLs or oil prices than our competitors who engage in derivative transactions. Lower natural gas and oil prices may also negatively impact our ability to enter into derivative contracts at favorable prices.

Many of our current and potential competitors have greater resources than we have and we may not be able to successfully compete in acquiring, exploring and developing new properties

We face competition in every aspect of our business, including, but not limited to, acquiring reserves and leases, obtaining goods, services and employees needed to operate and manage our business and marketing natural gas, NGLs or oil. Competitors include multinational oil companies, independent production companies and individual producers and operators. Many of our competitors have greater financial and other resources than we do. As a result, these competitors may be able to address these competitive factors more effectively than we can or weather industry downturns more easily than we can. For more discussion regarding competition, see “Items 1 and 2. Business and Properties – Competition.”

We could experience periods of higher costs if commodity prices rise. These increases could reduce our profitability, cash flow and ability to complete development activities as planned

Historically, our capital and operating costs have risen during periods of increasing oil, NGLs and gas prices. These cost increases result from a variety of factors beyond our control, such as increases in the cost of electricity, steel and other raw materials that we and our vendors rely upon; increased demand for labor, services and materials as drilling activity increases; and increased taxes. Increased levels of drilling activity in the natural gas and oil industry in recent periods have led to increased costs of some drilling equipment, materials and supplies. Such costs may rise faster than increases in our revenue, thereby negatively impacting our profitability, cash flow and ability to complete development activities as scheduled and on budget.

The natural gas and oil industry is subject to extensive regulation

The natural gas and oil industry is subject to various types of regulations in the United States by local, state and federal agencies. Legislation affecting the industry is under constant review for amendment or expansion, frequently increasing our regulatory burden. Numerous departments and agencies, both state and federal, are authorized by statute to issue rules and regulations binding on participants in the natural gas and oil industry. Compliance with such rules and regulations often increases our cost of doing business, delays our operations and, in turn, decreases our profitability.

Our operations are subject to numerous and increasingly strict federal, state and local laws, regulations and enforcement policies relating to the environment. We may incur significant costs and liabilities in complying with existing or future environmental laws, regulations and enforcement policies and may incur costs arising out of property or natural resource damage or injuries to employees and other persons. These costs may result from our current and former operations and even may be caused by previous owners of property we own or lease or relate to third party sites where we have taken materials for recycling or disposal. Failure to comply with these laws and regulations may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties as well as corrective actions orders. Matters subject to regulation include:

- the amounts and types of substances and materials that may be released into the environment;
- response to unexpected releases to the environment;
- reports and permits concerning exploration, drilling, production and other regulated activities;
- the spacing of wells;
- unitization and pooling of properties;
- calculating royalties on oil and gas produced under federal and state leases; and
- taxation.

Under these laws and regulations, we could be liable for personal injuries, property damage, oil spills, discharge of hazardous materials, remediation and clean-up costs, natural resource damages and other environmental damages. We also could be required to install expensive pollution control measures or limit or cease activities on lands located within wilderness, wetlands or other environmentally or politically sensitive areas. If we incur these costs or damages it may reduce or eliminate funds available for exploration, development or acquisitions or cause us to incur losses.

The subject of climate change is receiving increasing attention from scientists, legislators and governmental agencies. There is an ongoing debate as to the extent to which our climate is changing, the potential causes of this change and its potential impacts. Some attribute global warming to increased levels of greenhouse gases ("GHGs"), including carbon dioxide and methane, which has led to significant legislative and regulatory efforts to limit GHG emissions.

There are a number of legislative and regulatory initiatives to address GHG emissions, which are in various phases of discussion or implementation. The outcome of federal and state actions to address global climate change could result in a variety of regulatory programs including potential new regulations to control or restrict emissions, taxes or other charges to deter emissions of GHGs, energy efficiency requirements to reduce demand, or other regulatory actions. These actions could:

- result in increased costs associated with our operations;
- increase other costs to our business;
- affect the demand for natural gas; and
- impact the prices we charge our customers.

Adoption of federal or state requirements mandating a reduction in GHG emissions could have far-reaching and significant impacts on the energy industry and the U.S. economy. We cannot predict the potential impact of such laws or regulations on our future consolidated financial condition, results of operations or cash flows. For more information regarding the environmental regulation of our business, see "Items 1 and 2. Business and Properties – Environment and Occupational Health and Safety Matters."

Our business is subject to operating hazards that could result in substantial losses or liabilities that may not be fully covered under our insurance policies

Natural gas, NGLs and oil operations are subject to many risks, including well blowouts, craterings, explosions, uncontrollable flows of oil, natural gas or well fluids, fires, pipe or cement failures, pipeline ruptures or spills, vandalism, pollution, releases of toxic gases, adverse weather conditions or natural disasters, and other environmental hazards and risks. If any of these hazards occur, we could sustain substantial losses as a result of:

- injury or loss of life;
- severe damage to or destruction of property, natural resources and equipment;
- pollution or other environmental damage;
- investigatory and cleanup responsibilities;
- regulatory investigations and penalties or lawsuits;
- suspension of operations; and
- repairs to resume operations.

We maintain insurance against many, but not all, potential losses or liabilities arising from our operations in accordance with what we believe are customary industry practices and in amounts and at costs that we believe to be prudent and commercially practicable. Our insurance includes deductibles that must be met prior to recovery, as well as sub-limits and/or self-insurance. Additionally, our insurance is subject to exclusions and limitations. Our insurance does not cover every potential risk associated with our operations, including the potential loss of significant revenues. We can provide no assurance that our coverage will adequately protect us against liability from all potential consequences, damages and losses.

We currently have insurance policies covering our operations that include coverage for general liability, excess liability, physical damage to our oil and gas properties, operational control of wells, oil pollution, third-party liability, workers' compensation and employers liability and other coverages. Consistent with insurance coverage generally available to the industry, our insurance policies provide limited coverage for losses or liabilities relating to pollution, with coverage for sudden and accidental occurrences. For example, we maintain operator's extra expense coverage provided by third-party insurers for obligations, expenses or claims that we may incur from a sudden incident that results in negative environmental effects, including obligations, expenses or claims related to seepage and pollution, cleanup and containment, evacuation expenses and control of the well (subject to policy terms and conditions). In the specific event of a well blowout or out-of-control well resulting in negative environmental effects, such operator's extra expense coverage would be our primary source of coverage, with the general liability and excess liability coverage referenced above also providing certain coverage.

In the event we make a claim under our insurance policies, we will be subject to the credit risk of the insurers. Volatility and disruption in the financial and credit markets may adversely affect the credit quality of our insurers and impact their ability to pay claims.

Further, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. Some forms of insurance may become unavailable in the future or unavailable on terms that we believe are economically acceptable. No assurance can be given that we will be able to maintain insurance in the future at rates that we consider reasonable, and we may elect to maintain minimal or no insurance coverage. If we incur substantial liability from a significant event and the damages are not covered by insurance or are in excess of policy limits, then we would have lower revenues and funds available to us for our operations, that could, in turn, have a material adverse affect on our business, financial condition and results of operations.

Additionally, we rely to a large extent on facilities owned and operated by third parties, and damage to or destruction of those third-party facilities could affect our ability to process, transport and sell our production. To a limited extent, we maintain business interruption insurance related to a third party processing plant in Pennsylvania where we are insured for potential losses from the interruption of production caused by loss of or damage to the processing plant.

A change in the jurisdictional characterization of some of our assets by federal, state or local regulatory agencies or a change in policy by those agencies may result in increased regulation of our assets, which may cause our revenues to decline and operating expenses to increase

Section 1(b) of the NGA exempts natural gas gathering facilities from regulation by the FERC as a natural gas company under the NGA. We believe that the natural gas pipelines in our gathering systems meet the traditional tests the FERC has used to establish a pipeline's status as a gatherer not subject to regulation as a natural gas company. However, the distinction between the FERC-regulated transmission services and federally unregulated gathering services is the subject of ongoing litigation, so the classification and regulation of our gathering facilities are subject to change based on future determinations by the FERC, the courts, or Congress.

While our natural gas gathering operations are generally exempt from the FERC regulation under the NGA, our gas gathering operations may be subject to certain FERC reporting and posting requirements in a given year. The FERC has issued a final rule requiring certain participants in the natural gas market, including certain gathering facilities and natural gas marketers that engage in a minimum level of natural gas sales or purchases, to submit annual reports to the FERC on the aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to, or may contribute to, the formation of price indices.

Other FERC regulations may indirectly impact our businesses and the markets for products derived from these businesses. The FERC's policies and practices across the range of its natural gas regulatory activities, including, for example, its policies on open access transportation, gas quality, ratemaking, capacity release and market center promotion, may indirectly affect the intrastate natural gas market. In recent years, the FERC has pursued pro-competitive policies in its regulation of interstate natural gas pipelines. However, we cannot assure you that the FERC will continue this approach as it considers matters such as pipelines rates and rules and policies that may affect rights of access to transportation capacity. For more information regarding the regulation of our operations, see "Items 1 and 2. Business and Properties – Governmental Regulation."

Should we fail to comply with all applicable FERC administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines

Under the Energy Policy Act of 2005, the FERC has civil penalty authority under the NGA to impose penalties for current violations of up to $1 million per day for each violation and disgorgement of profits associated with any violation. While our operations have not been regulated as a natural gas company by the FERC under the NGA, the FERC has adopted regulations that may subject certain of our otherwise non-FERC jurisdiction facilities to the FERC annual reporting requirements. We also must comply with the anti-market manipulation rules enforced by the FERC. Additional rules and legislation pertaining to those and other matters may be considered or adopted by the FERC from time to time. Failure to comply with those regulations in the future could subject Range to civil penalty liability. For more information regarding the regulation of our operations, see "Items 1 and 2. Business and Properties – Governmental Regulation."

Certain federal income tax deductions currently available with respect to natural gas and oil exploration and development may be eliminated, and additional state taxes on natural gas extraction may be imposed, as a result of future legislation

Legislation has been proposed that would, if enacted into law, make significant changes to U.S. federal income tax laws, including the elimination of certain U.S. federal income tax benefits currently available to oil and gas exploration and production companies. Such changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and gas properties; (ii) the elimination of current deductions for intangible drilling and development costs; (iii) the elimination of the deduction for certain U.S. production activities; and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear, however, whether any such changes will be enacted or how soon such changes could be effective. As of December 31, 2013, we had a tax basis of $2.2 billion related to prior years capitalized intangible drilling costs, which will be amortized over the next five years.

The passage of this legislation or any other similar change in U.S. federal income tax law could eliminate or postpone certain tax deductions that are currently available with respect to natural gas and oil exploration and development, and any such change could negatively affect our financial condition and results of operations.

In February 2012, the state legislature of Pennsylvania passed a new natural gas impact fee in Pennsylvania, where the majority of our acreage in the Marcellus Shale is located. The legislation imposes an annual fee on natural gas and oil operators for each well drilled for a period of fifteen years. The fee is on a sliding scale set by the Public Utility Commission and is based on two factors: changes in the Consumer Price Index and the average NYMEX natural gas prices from the last day of each month. The passage of this legislation increases the financial burden on our operations in the Marcellus Shale. There can be no assurance that the impact fee will remain as currently structured or that additional taxes will not be imposed.

Federal, state and local legislative and regulatory initiatives relating to hydraulic fracturing, as well as governmental reviews of such activities, could result in increased costs and additional operating restrictions or delays and adversely affect our production

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under pressure into rock formations to stimulate hydrocarbon (natural gas and oil) production. We find that the use of hydraulic fracturing is necessary to produce commercial quantities of natural gas and oil from many reservoirs, especially shale formations such as the Marcellus Shale. The process is typically regulated by state oil and gas commissions. However, the EPA recently asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the Safe Drinking Water Act's Underground Injection Control Program and issued revised permitting guidance in February 2014 addressing the performance of such activities. There are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices and the EPA has commenced a study of potential environmental effects of hydraulic fracturing on drinking water and groundwater, with a final draft report drawing conclusions about the potential impacts of hydraulic fracturing on drinking water resources expected to be available for public comment and peer review in 2014. In addition, the EPA announced that it is launching a study regarding wastewater resulting from hydraulic fracturing activities and currently plans to propose standards in 2014 that such wastewater must meet before being transported to a treatment plant. Also, the U.S. Department of Energy has conducted an investigation into practices the agency could recommend to better protect the environment from drilling using hydraulic fracturing completion methods and in August 2011, issued a report on immediate and longer term actions that may be taken to reduce environmental a safety risks of shale gas development while the U.S. Department of the Interior published a supplemental notice of proposed rulemaking in May 2013, governing proposed disclosure, well testing and monitoring requirements for hydraulic fracturing on federal lands. At the same time, legislation has been introduced before Congress from time to time to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process, but none of this legislation was adopted. In addition, some states have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, disclosure and well construction requirements on hydraulic fracturing operations. For example, Texas, Pennsylvania, Colorado, West Virginia and Wyoming have each adopted a variety of well construction, set back, or disclosure regulations limiting how fracturing can be performed and requiring various degrees of chemical disclosure. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations. In addition, if hydraulic fracturing becomes regulated at the federal level as a result of federal legislation or regulatory initiatives by the EPA, our fracturing activities could become subject to additional permitting requirements and also to possible permitting delays and potential increases in costs that could have an adverse effect on our level of production.

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

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Act"), enacted on July 21, 2010, established federal oversight and regulation of the over-the-counter derivatives market and entities, including Range, that participate in that market. The Act requires the CFTC and the SEC to promulgate rules and regulations implementing the Act. Although the CFTC has finalized certain regulations, other remain to the finalized or implemented and it is not possible at this time to predict when this will be accomplished.

In October 2011, the CFTC issued regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. The initial position limits rule was vacated by the United States District Court for the District of Colombia in September 2012. However, in November 2013, the CFTC proposed new rules that would place limits on positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide hedging transactions. As these new position limit rules are not yet final, the impact of those provisions on us is uncertain at this time.

The CFTC has designated certain interest rate swaps and credit default swaps for mandatory clearing and the associated rules also will require us, in connection with covered derivative activities, to comply with clearing and trade-execution requirements or take steps to qualify for an exemption to such requirements. Although we expect to qualify for the end-user exception from the mandatory clearing requirements for swaps entered to hedge our commercial risks, the application of the mandatory clearing and trade execution requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. In addition, for uncleared swaps, the CFTC or federal banking regulators may require end-users to enter into credit support documentation and/or post initial and variation margin. Posting of collateral could impact liquidity and reduce cash available to us for capital expenditures, therefore reducing our ability to execute hedges to reduce risk and protect cash flows. The proposed margin rules are not yet final, and therefore the impact of those provisions to us is uncertain at this time.

The Act also may require the counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty.

The full impact of the Act and related regulatory requirements upon our business will not be known until the regulations are implemented and the market for derivatives contracts has adjusted. The Act and new regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts or increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the Act and regulations implementing the Act, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures.

Finally, the Act was intended, in part, to reduce the volatility of oil and gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and gas. Our revenues could therefore be adversely affected if a consequence of the Act and implementing regulations is to lower commodity prices.

Laws and regulations pertaining to threatened and endangered species could delay or restrict our operations and cause us to incur substantial costs

Various federal and state statutes prohibit certain actions that adversely affect endangered or threatened species and their habitats, migratory birds, wetlands and natural resources. These statues include the ESA, the Migratory Bird Treaty Act, the CWA and CERCLA. The U.S. Fish and Wildlife Service may designate critical habitat and suitable habitat areas that it believes are necessary for survival of threatened or endangered species. A critical habitat or suitable habitat designation could result in further material restrictions to federal land use and private land use and could delay or prohibit land access or oil and gas development. If harm to species or damages to wetlands, habitat or natural resources occur or may occur, government entities or, at times, private parties may act to prevent oil and gas exploration or development activities or seek damages for harm to species, habitat or natural resources resulting from drilling or construction or releases of oil, wastes, hazardous substances or other regulated materials, and, in some cases, may seek criminal penalties. Moreover, as a result of a settlement approved by the U.S. District Court for the District of Columbia in September 2011, the U.S. Fish and Wildlife Service is required to consider listing numerous species as endangered or threatened under the ESA before completion of the agency's 2017 fiscal year. The designation of previously unprotected species as threatened or endangered in areas where we conduct operations could cause us to incur increased costs arising from species protection measures or could result in limitations on its exploration and production activities that could have an adverse effect on our ability to develop and produce reserves.

Our business depends on natural gas and oil transportation and NGLs processing facilities, most of which are owned by others and depends on our ability to contract with those parties

Our ability to sell our natural gas, NGLs and oil production depends in part on the availability, proximity and capacity of pipeline systems and processing facilities owned by third parties and our ability to contract with those third parties. The lack of available capacity on these systems and facilities could result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. Although we have some contractual control over the transportation of our product, material changes in these business relationships including the financial condition of these third parties, could materially affect our operations. In some cases, we do not purchase firm transportation on third party facilities and therefore, our production transportation can be interrupted by those having firm arrangements. We have entered into firm transportation arrangements in the Marcellus Shale where we are obligated to pay fees on minimum volumes regardless of actual volume throughput. We have also entered into long-term agreements with third parties to provide natural gas gathering and processing services in the Marcellus Shale. In some cases, the capacity of gathering systems and transportation pipelines may be insufficient to accommodate potential production from existing and new wells. Federal and state regulation of natural gas and oil production and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines and general economic conditions could adversely affect our ability to produce, gather and transport natural gas, NGLs and oil. If any of these third party pipelines and other facilities become partially or fully unavailable to transport or process our product, or if the natural gas quality specifications for a natural gas pipeline or facility changes so as to restrict our ability to transport natural gas on those pipelines or facilities, our revenues could be adversely affected.

The disruption of third-party facilities due to maintenance and/or weather could negatively impact our ability to market and deliver our products. In particular, the disruption of certain third-party natural gas processing facilities in the Marcellus Shale could materially affect our ability to market and deliver natural gas production in that area. We have no control over when or if such facilities are restored and generally have no control over what prices will be charged. A total shut-in of production could materially affect us due to a lack of cash flow, and if a substantial portion of the production is hedged at lower than market prices, those financial hedges would have to be paid from borrowings absent sufficient cash flow.

Currently, there is little demand, or facilities to supply the existing demand elsewhere, for ethane in the Appalachian region. We have announced three ethane agreements wherein we have contracted to either sell or transport ethane from our Marcellus Shale area, two of which began initial deliveries in late 2013, and the final one expected to begin operations in mid-2015. We cannot assure you that all these facilities will become or will remain available.

Acquisitions are subject to the risks and uncertainties of evaluating reserves and potential liabilities and may be disruptive and difficult to integrate into our business

We could be subject to significant liabilities related to our acquisitions. It generally is not feasible to review in detail every individual property included in an acquisition. Ordinarily, a review is focused on higher valued properties. However, even a detailed review of all properties and records may not reveal existing or potential problems in all of the properties, nor will it permit us to become sufficiently familiar with the properties to assess fully their deficiencies and capabilities. We do not always inspect every well we acquire, and environmental problems, such as groundwater contamination, are not necessarily observable even when an inspection is performed.

In addition, there is intense competition for acquisition opportunities in our industry. Competition for acquisitions may increase the cost of, or cause us to refrain from, completing acquisitions. Our acquisition strategy is dependent upon, among other things, our ability to obtain debt and equity financing and, in some cases, regulatory approvals. Our ability to pursue our acquisition strategy may be hindered if we are unable to obtain financing on terms acceptable to us or regulatory approvals.

Acquisitions often pose integration risks and difficulties. In connection with recent and future acquisitions, the process of integrating acquired operations into our existing operations may result in unforeseen operating difficulties and may require significant management attention and financial resources that would otherwise be available for the ongoing development or expansion of existing operations. Future acquisitions could result in our incurring additional debt, contingent liabilities, expenses and diversion of resources, all of which could have a material adverse effect on our financial condition and operating results.

We may be unable to dispose of nonstrategic assets on attractive terms, and may be required to retain liabilities for certain matters

We regularly review our property base for the purpose of identifying nonstrategic assets, the disposition of which would increase capital resources available for other activities and create organizational and operational efficiencies. Various factors could materially affect our ability to dispose of nonstrategic assets or complete announced dispositions, including the availability of purchasers willing to purchase the nonstrategic assets at prices acceptable to us. Sellers typically retain certain liabilities for certain matters. The magnitude of any such retained liability or indemnification obligation may be difficult to quantify at the time of the transaction and ultimately may be material. Also, as is typical in divestiture transactions, third parties may be unwilling to release us from guarantees or other credit support provided prior to the sale of the divested assets. As a result, after a sale, we may remain secondarily liable for the obligations guaranteed or supported to the extent that the buyer of the assets fails to perform these obligations.

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

Our success is highly dependent on our management personnel and none of them is currently subject to an employment contract. 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.

We have limited control over the activities on properties we do not operate

Other companies operate some of the properties in which we have an interest. We operate approximately 85% of our wells, as of December 31, 2013. We have limited ability to influence or control the operation or future development of non-operated properties or the amount of capital expenditures that we are required to fund with respect to them. The failure of an operator of our wells to adequately perform operations, an operator’s breach of the applicable agreements or an operator’s failure to act in ways that are in our best interest could reduce our production and revenues. Our dependence on the operator and other working interest owners for these projects and our limited ability to influence or control the operation and future development of these properties could materially adversely affect the realization of our targeted returns on capital in drilling or acquisitions activities and lead to unexpected future costs.

We exist in a litigious environment

Any constituent could bring suit regarding our existing or planned operations or allege a violation of an existing contract. Any such action could delay when planned operations can actually commence or could cause a halt to existing production until such alleged violations are resolved by the courts. Not only could we incur significant legal and support expenses in defending our rights, but halting existing production or delaying planned operations could impact our future operations and financial condition. Such legal disputes could also distract management and other personnel from their primary responsibilities.

Our business could be negatively affected by security threats, including cybersecurity threats, and other disruptions

As a natural gas and oil producer, we face various security threats, including cybersecurity threats to gain unauthorized access to sensitive information or to render data or systems unusable; 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. The potential for such security threats has subjected our operations to increased risks that could have a material adverse effect on our business. In particular, our implementation of various procedures and controls to monitor and mitigate security threats and to increase security for our information, facilities and infrastructure may result in increased capital and operating costs. Moreover, there can be no assurance that such procedures and controls will be sufficient to prevent security breaches from occurring. If any of these security breaches were to occur, they could lead to losses of sensitive information, critical infrastructure or capabilities essential to our operations and could have a material adverse effect on our reputation, financial position, results of operations or cash flows. Cybersecurity attacks in particular are becoming more sophisticated 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, and corruption of data. These events could damage our reputation and lead to financial losses from remedial actions, loss of business or potential liability.

Conservation measures and technological advances could reduce demand for oil and natural gas

Fuel conservation measures, alternative fuel requirements, governmental requirements for renewable energy resources, increasing consumer demand for alternatives to oil and natural gas, technological advances in fuel economy and energy generation devices could reduce demand for oil and natural gas. The impact of the changing demand for oil and natural gas services and products may have a material adverse effect on our business, financial condition, results of operations and cash flows.

Our financial statements are complex

Due to United States generally accepted accounting principles and the nature of our business, our financial statements continue to be complex, particularly with reference to derivatives, asset retirement obligations, equity awards, deferred taxes, the accounting for our deferred compensation plans and discontinued operations. We expect such complexity to continue and possibly increase.

Risks Related to Our Common Stock

Common stockholders will be diluted if additional shares are issued

In 2005, 2006, 2007 and 2008, we sold 52.7 million shares of common stock to finance acquisitions or pay down our outstanding bank credit facility. In 2009 and 2010, we issued 1.1 million shares of common stock to purchase acreage in the Marcellus Shale. Our ability to repurchase securities for cash is limited by our bank credit facility and our senior subordinated note agreements. We also issue restricted stock and stock appreciation rights to our employees and directors as part of their compensation. In addition, we may issue additional shares of common stock, additional subordinated notes or other securities or debt convertible into common stock, to extend maturities or fund capital expenditures, including acquisitions. If we issue additional shares of our common stock in the future, it may have a dilutive effect on our current outstanding stockholders.

Dividend limitations

Limits on the payment of dividends and other restricted payments, as defined, are imposed under our bank credit facility and under our senior subordinated note agreements. These limitations may, in certain circumstances, limit or prevent the payment of dividends independent of our dividend policy.

Our stock price may be volatile and you may not be able to resell shares of our common stock at or above the price you paid

The price of our common stock fluctuates significantly, which may result in losses for investors. The market price of our common stock has been volatile. From January 1, 2011 to December 31, 2013, the price of our common stock reported by the New York Stock Exchange ranged from a low of $44.20 per share to a high of $85.49 per share. We expect our stock to continue to be subject to fluctuations as a result of a variety of factors, including factors beyond our control. These factors include:

- changes in natural gas, NGLs and oil prices;
- variations in quarterly drilling, recompletions, acquisitions and operating results;
- changes in governmental regulation and/or taxation;
- changes in financial estimates by securities analysts;
- changes in market valuations of comparable companies;

- additions or departures of key personnel; or
- future sales of our stock and changes in our capital structure.

We may fail to meet expectations of our stockholders or of securities analysts at some time in the future and our stock price could decline as a result.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 3. LEGAL PROCEEDINGS

We are the subject of, or party to, a number of pending or threatened legal actions and claims arising in the ordinary course of our business. While many of these matters involve inherent uncertainty, we believe that the amount of the liability, if any, ultimately incurred with respect to proceedings or claims will not have a material adverse effect on our consolidated financial position as a whole or on our liquidity, capital resources or future annual results of operations. We will continue to evaluate our litigation quarterly and will establish and adjust any litigation reserves as appropriate to reflect our assessment of the then current status of litigation.

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 Common Stock

Our common stock is listed on the New York Stock Exchange ("NYSE") under the symbol "RRC." During 2013, trading volume averaged 1.6 million shares per day. The following table shows the quarterly high and low sale prices and cash dividends declared as reported on the NYSE composite tape for the past two years.

	High	Low	Cash Dividends Declared
2012:			
First quarter	$ 68.50	$ 52.34	$ 0.04
Second quarter	69.18	53.09	0.04
Third quarter	72.48	56.50	0.04
Fourth quarter	73.94	61.03	0.04
2013:			
First quarter	$ 83.15	$ 61.25	$ 0.04
Second quarter	81.13	71.14	0.04
Third quarter	85.23	74.66	0.04
Fourth quarter	85.49	72.54	0.04

Between January 1, 2014 and February 24, 2014, the common stock traded at prices between $79.28 and $89.19 per share. Our senior subordinated notes are not listed on an exchange, but trade over-the-counter.

Holders of Record

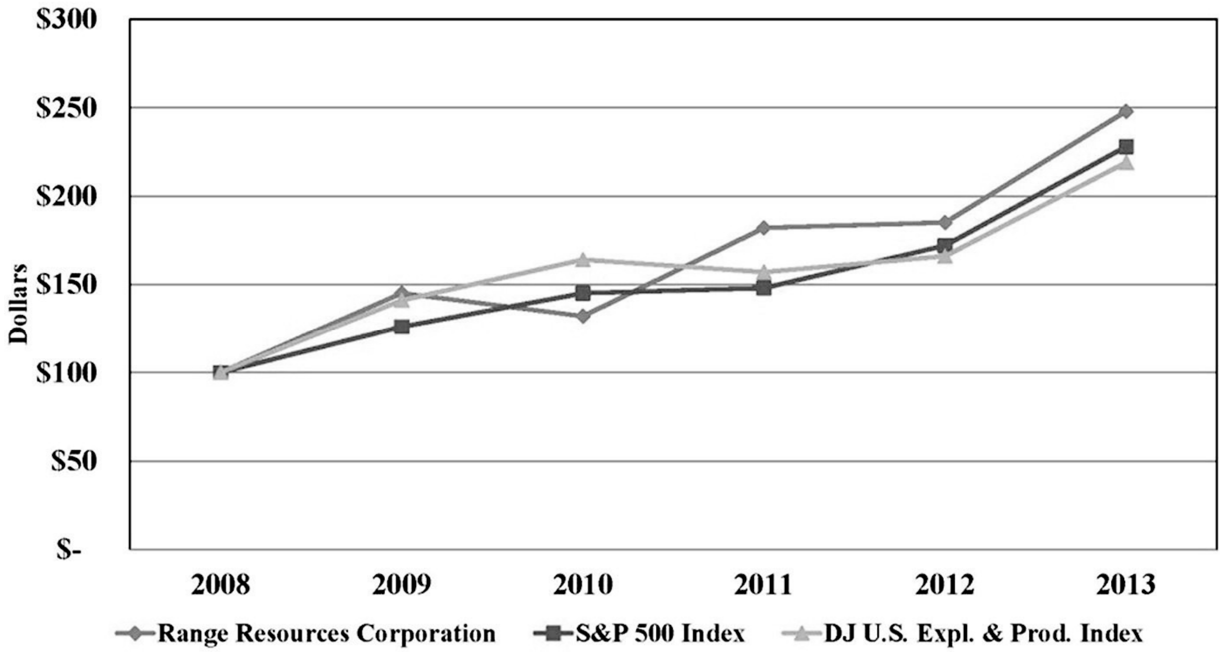
On February 24, 2014, there were approximately 1,216 holders of record of our common stock.

Dividends

The payment of dividends is subject to declaration by the board of directors and depends on earnings, capital expenditures and various other factors. The board of directors declared quarterly dividends of $0.04 per common share for each of the four quarters of 2013, 2012 and 2011. The bank credit facility and our senior subordinated notes allow for the payment of common and preferred dividends, with certain limitations. The determination of the amount of future dividends, if any, to be declared and paid is at the sole discretion of our board of directors and will depend upon our level of earnings and capital expenditures and other matters that the board deems relevant. Dividends on Range common stock are limited to our legally available funds. For more information, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

Stockholder Return Performance Presentation*

The following graph is included in accordance with the SEC's executive compensation disclosure rules. This historic stock price performance is not necessarily indicative of future stock performance. The graph compares the change in the cumulative total return of Range's common stock, the Dow Jones U.S. Exploration and Production Index, and the S&P 500 Index for the five years ended December 31, 2013. The graph assumes that $100 was invested in the Company's common stock and each index on December 31, 2008 and that dividends were reinvested.



	2008	2009	2010	2011	2012	2013
Range Resources Corporation	$ 100	$ 145	$ 132	$ 182	$ 185	$ 248
S&P 500 Index	100	126	145	148	172	228
DJ U.S. Expl. & Prod. Index	100	141	164	157	166	219

*The performance graph and the information contained in this section is not "soliciting material," is being "furnished" not "filed" with the SEC and is not to be incorporated by reference into any of our filings under the Securities Act or the Exchange Act whether made before or after the date hereof and irrespective of any general incorporation language contained in such filing.

ITEM 6. SELECTED FINANCIAL DATA AND RESERVE DATA

The following table shows selected financial information for the five years ended December 31, 2013. Significant producing property dispositions may affect the comparability of year-to-year financial and operating data. In the first half of 2013, we sold certain Delaware and Permian Basin properties in Southeast New Mexico and West Texas for proceeds of $275.0 million. In the first half of 2011, we sold our Barnett Shale properties for proceeds of $889.3 million, including certain derivative contracts assumed by the buyer and these operations are reflected as discontinued operations. In the first half of 2010, we sold our Ohio properties for proceeds of $323.0 million. This information should be read in conjunction with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations," and our consolidated financial statements and related notes included elsewhere in this report (in thousands except per share or per mcfe data).

	Year Ended December 31,				
	2013	2012	2011	2010	2009
Statements of Operations Data:					
Natural gas, NGLs and oil sales	$ 1,715,676	$ 1,351,694	$ 1,173,266	$ 823,290	$ 751,749
Total revenues and other income	1,862,719	1,457,704	1,230,642	961,397	831,095
Total costs and expenses	1,713,140	1,432,648	1,152,379	821,789	746,322
Income from continuing operations	115,722	13,002	42,706	88,698	38,980
Discontinued operations, net of taxes	—	—	15,320	(327,954)	(92,850)
Net income (loss)	115,722	13,002	58,026	(239,256)	(53,870)
Income from continuing operations per share:					
–Basic	$ 0.71	$ 0.08	$ 0.26	$ 0.56	$ 0.25
–Diluted	0.70	0.08	0.26	0.55	0.24
Net income (loss) per share:					
–Basic	0.71	0.08	0.36	(1.53)	(0.35)
–Diluted	0.70	0.08	0.36	(1.52)	(0.34)
Costs per mcfe: [(a)]					
Direct operating expense	$ 0.37	$ 0.42	$ 0.60	$ 0.69	$ 0.85
Production and ad valorem tax expense	0.13	0.24	0.15	0.19	0.22
General and administrative expense	0.85	0.63	0.80	1.01	1.00
Interest expense	0.51	0.61	0.66	0.65	0.65
Depletion, depreciation and amortization expense	1.44	1.62	1.80	1.98	2.32
	$ 3.30	$ 3.52	$ 4.01	$ 4.52	$ 5.04
Average Daily Production:					
Natural gas (mcf)	724,735	591,679	397,825	290,815	248,138
NGLs (bbls)	25,356	19,036	14,664	9,864	4.343
Oil (bbls)	10,486	7,790	5,369	5,300	6,912
Total mcfe [(b)]	939,786	752,637	518,019	381,800	315,668
Balance Sheets Data:					
Current assets [(c)]	$ 248,301	$ 327,614	$ 315,263	$ 1,113,570	$ 182,810
Current liabilities [(d)]	495,561	455,143	511,932	443,690	321,634
Natural gas and oil properties, net	6,758,437	6,096,184	5,157,566	4,084,013	3,551,635
Total assets	7,299,086	6,728,735	5,845,470	5,511,714	5,403,411
Bank debt	500,000	739,000	187,000	274,000	324,000
Subordinated notes	2,640,516	2,139,185	1,787,967	1,686,536	1,383,833
Stockholders' equity [(e)]	2,414,452	2,357,392	2,392,420	2,223,761	2,378,589
Weighted average diluted shares outstanding	161,407	160,307	159,441	158,428	158,778
Cash dividends declared per common share	0.16	0.16	0.16	0.16	0.16
Statements of Cash Flows Data:					
Net cash provided from operating activities	$ 743,538	$ 647,099	$ 631,637	$ 513,322	$ 591,675
Net cash used in investing activities	(983,436)	(1,528,558)	(547,981)	(798,858)	(473,807)
Net cash provided from (used in) financing activities	239,994	881,619	(86,412)	287,617	(117,854)
Proved Reserves Data [(f)] **(at end of period):**					
Natural gas (Bcf)	5,666	4,793	4,010	3,567	2,615
NGLs (Mmbbls)	374	240	142	123	52
Oil and condensate (Mmbbls)	48	45	31	23	34
Total proved reserves (Bcfe)	8,202	6,506	5,054	4,442	3,129

(a) These are costs we believe fluctuate on a unit-of-production, or per mcfe basis.

(b) Oil and NGLs are converted to mcfe at the rate of one barrel equals six mcf based upon the approximate energy content of oil and natural gas, which is not indicative of the relationship of oil and natural gas prices.

(c) 2010 includes $877.6 million assets of discontinued operations compared to $43.5 million in 2009. 2013 includes $51.4 million deferred tax assets compared to $8.1 million in 2009. 2013 includes $4.4 million of unrealized derivative assets compared to $137.6 million in 2012, $173.9 million in 2011, $123.3 million in 2010 and $21.5 million in 2009.

(d) 2013 includes $26.2 million of unrealized derivative liabilities compared to $352,000 in 2010 and $14.5 million in 2009. 2012 includes a $37.9 million deferred tax liability compared to $56.6 million in 2011 and $11.8 million in 2010.

(e) Stockholders' equity includes other comprehensive income of $6.2 million in 2013 compared to $83.9 million in 2012, $156.6 million in 2011, $67.5 million in 2010 and $6.4 million in 2009.

(f) Effective December 31, 2009, we adopted revised authoritative accounting and disclosure requirements for natural gas and oil reserves.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion is intended to assist you in understanding our business and results of operations together with our present financial condition. Certain sections of Management's Discussion and Analysis of Financial Condition and Results of Operations include forward-looking statements concerning trends or events potentially affecting our business. These statements contain words such as "anticipate," "believe," "estimate," "expect," "forecast," "plan," "project," "target," "could," "may," "should," "would" or similar words indicating that future outcomes are uncertain. In accordance with "safe harbor" provisions for the Private Securities Litigation Reform Act of 1995, these statements are accompanied by cautionary language identifying important factors, though not necessarily all such factors, which could cause future outcomes to differ materially from those set forth in the forward-looking statements. Management's Discussion and Analysis of Financial Condition and Results of Operations should be read in conjunction with the information under Items 1 and 2. Business and Properties, Item 1A. Risk Factors, Item 6. Selected Financial Data and Item 8. Financial Statements Data in this report. Unless otherwise indicated, the information included herein relates to our continuing operations.

Overview of Our Business

We are an independent natural gas, natural gas liquids ("NGLs") and oil company engaged in the exploration, development and acquisition of natural gas and crude oil properties in the Appalachian and Southwestern regions of the United States. We operate in one segment and have a single company-wide management team that administers all properties as a whole rather than by discrete operating segments. We track only basic operational data by area. We do not maintain complete separate financial statement information by area. We measure financial performance as a single enterprise and not on an area-by-area basis.

Our objective is to build stockholder value through consistent growth in reserves and production on a cost-efficient basis. Our strategy to achieve our objective is to increase reserves and production through internally generated drilling projects occasionally coupled with complementary acquisitions. Our revenues, profitability and future growth depend substantially on prevailing prices for natural gas, NGLs, crude oil and condensate and on our ability to economically find, develop, acquire and produce natural gas, NGLs and oil reserves. Prices for natural gas, NGLs and oil fluctuate widely and affect:

- the amount of cash flows available for capital expenditures;
- our ability to borrow and raise additional capital; and
- the quantity of natural gas, NGLs and oil we can economically produce.

We prepare our financial statements in conformity with generally accepted accounting principles, which require us to make estimates and assumptions that affect our reported results of operations and the amount of our reported assets, liabilities and proved natural gas, NGLs and oil reserves. We use the successful efforts method of accounting for our natural gas, NGLs and oil activities. Our corporate headquarters is located in Fort Worth, Texas.

Source of Our Revenues

We derive our revenues from the sale of natural gas, NGLs, oil and condensate that is produced from our properties. Revenues from product sales are a function of the volumes produced, prevailing market prices, product quality, gas Btu content and transportation costs. We generally sell natural gas, NGLs and oil under two types of agreements, which are common in our industry. Both types of agreements include transportation charges. One type of agreement is a netback agreement, under which we sell natural gas and oil at the wellhead and collect a price, net of transportation incurred by the purchaser. In this case, we record revenue at the price we receive from the purchaser. In the case of NGLs, we generally receive a net price from the purchaser (which is net of processing costs) and is also recorded in revenue at the net price we receive from the purchaser. Under the other type of agreement, we sell natural gas or oil at a specific delivery point, pay transportation to a third party and receive proceeds from the purchaser with no transportation deduction. In that case, we record transportation costs as transportation, gathering and compression expense. Also included in natural gas, NGLs and oil sales revenues and derivative fair value income or loss are the effects of derivative accounting. Derivatives included in natural gas, NGLs and oil sales reflect settlements on those derivatives that qualify for hedge accounting. Cash settlements of derivative contracts that are not accounted for as hedges are included in derivative fair value income or loss in the accompanying statements of operations. Effective March 1, 2013, we elected to de-designate all commodity contracts that were previously designated as cash flow hedges and elected to discontinue hedge accounting prospectively. For more information, see Note 11 to our consolidated financial statements. Brokered natural gas, marketing and other revenues include revenue received from brokered gas or revenue we receive as a result of selling (and buying) natural gas that is not related to our production, marketing fees we receive from third parties, transportation revenue we receive from gathering lines we own and equity method investments. Discontinued operations include our Barnett Shale properties, which were sold in April 2011.

Principal Components of Our Cost Structure

- *Direct operating.* These are day-to-day costs incurred to bring hydrocarbons out of the ground along with the daily costs incurred to maintain our producing properties. Such costs include compensation of our field employees, maintenance, repairs and workover expenses related to our natural gas and oil properties. These costs are expected to remain a function of supply and demand. Direct operating expenses also include stock-based compensation expense (non-cash) associated with the amortization of restricted stock grants as part of the compensation of field employees.
- *Transportation, gathering and compression.* Under some of our sales arrangements, we sell natural gas and NGLs at a specific delivery point, pay transportation, gathering and compression costs to a third party and receive proceeds from the purchaser with no deduction. These costs represent those transportation, gathering and compression costs paid by Range to third parties.
- *Production and ad valorem taxes.* Production taxes are paid on produced natural gas and oil based on a percentage of sales revenue (excluding derivatives) or at fixed rates established by the applicable federal, state or local taxing authorities. Ad valorem taxes are generally based on reserve values at the end of each year. The Pennsylvania impact fee on unconventional natural gas and oil production, which includes the Marcellus Shale, is also included in this category.
- *Brokered natural gas and marketing.* These expenses are gas purchases for brokered gas or natural gas that we buy (and sell) that is not related to our production and overhead, including payroll and benefits for our marketing staff. Brokered natural gas and marketing also includes stock-based compensation expense (non-cash) associated with the amortization of restricted stock and stock appreciation rights ("SARs") granted as part of our marketing staffs compensation.
- *Exploration.* These are geological and geophysical costs, including payroll and benefits for the geological and geophysical staff, seismic costs, delay rentals and the costs of unsuccessful exploratory dry holes. Exploration expense also includes stock-based compensation expense (non-cash) associated with the amortization of grants of SARs and restricted stock as part of the compensation of our exploration staff.
- *Abandonment and impairment of unproved properties.* This category includes unproved property impairment and expenses associated with lease expirations.
- *General and administrative.* These costs include overhead, including payroll and benefits for our corporate staff, costs of maintaining our headquarters, costs of managing our production and development operations, franchise taxes, audit and other professional fees, legal compliance and legal settlements. Included in this category are overhead expense reimbursements we receive from working interest owners of properties, for which we serve as the operator. These reimbursements are received during both the drilling and operational stages of a property's life. General and administrative expense also includes stock-based compensation expense (non-cash) associated with grants of SARs and the amortization of restricted stock grants as part of the compensation of our corporate staff.
- *Deferred compensation plan.* These costs relate to the increase or decrease in the value of the liability associated with our deferred compensation plan. Our deferred compensation plan gives directors, officers and key employees the ability to defer all or a portion of their salaries and bonuses and invest in our common stock or make other investments at the individual's discretion. The assets of this plan are held in a grantor trust, are funded on the grant date and are available to satisfy the claims of our creditors in the event of bankruptcy or insolvency.
- *Interest expense.* We typically finance a portion of our cash requirements with borrowings under our bank credit facility and with longer-term debt securities. As a result, we incur interest expense that is affected by both fluctuations in interest rates and our financing decisions. We will likely continue to incur interest expense as we continue to grow. We currently have no capitalized interest.
- *Depreciation, depletion and amortization.* This includes the systematic expensing of the capitalized costs incurred to acquire, explore and develop natural gas, NGLs and oil. As a successful efforts company, we capitalize all costs associated with our acquisition and development efforts and all successful exploration efforts, and apportion these costs to each unit of production through depreciation, depletion and amortization expense. This expense also includes the systematic, monthly accretion of the future abandonment costs of tangible assets such as wells, service assets, pipelines, and other facilities.
- *Income taxes.* We are subject to state and federal income taxes but are currently not in a cash taxpaying position for federal income taxes, primarily due to the current deductibility and/or accelerated amortization of intangible drilling costs ("IDC"). At this time, we generally do not pay significant state income taxes due to our state net operating loss carryovers and our ability to follow the federal treatment of deducting IDC in most of the states in which we operate. Currently, substantially all of our federal taxes are deferred and we anticipate using all of our federal net operating loss carryforwards. As of December 31, 2013, we have a $3.0 million valuation allowance on our Pennsylvania net loss carryforwards due to the limitation on the amount of NOL that can be used per year. For more information, see "Item 1A. Risk Factors-*Certain federal income tax deductions currently available with respect to natural gas and oil exploration and development may be eliminated, and additional state taxes on natural gas extraction may be imposed, as a result of future legislation*."

Management's Discussion and Analysis of Results of Operations

Overview of 2013 Results

During 2013, we achieved the following financial and operating results:

- achieved 25% annual production growth;
- achieved 26% annual proved reserve growth;
- drilled 208.6 net wells with a 99% success rate;
- continued expansion of our activities in the Marcellus Shale by growing production, proving up acreage and acquiring additional unproved acreage;
- reduced direct operating expenses per mcfe 12% from the same period of 2012;
- reduced our DD&A rate 11% from the same period of 2012;
- continued to focus on financial flexibility by issuing $750.0 million of new 10-year 5% senior subordinated notes and achieved a debt per mcfe of proved reserves of $0.38 compared to $0.44 in 2012;
- redeemed all $250.0 million aggregate principal amount of our 7.25% senior subordinated notes due 2018;
- entered into additional commodity-based derivative contracts for 2014, 2015 and 2016;
- received $275.0 million of proceeds from the sale of our Southeast New Mexico and certain West Texas properties and $40.5 million of proceeds from the sale of other miscellaneous oil and gas assets;
- realized $743.5 million of cash flow from operating activities;
- ended the year with stockholders' equity of $2.4 billion; and
- began selling ethane at the tailgate of a third party processing facility for further delivery to Canada in addition to transporting ethane to the Gulf Coast.

Operationally, our 2013 performance reflects another year of successfully executing our strategy of growth through drilling. Our success enabled us to increase proved reserves by approximately 1.7 Tcfe, which is more than four times 2013 production. As evidenced by history, the prices to sell our production are volatile and we have no control over them. Therefore, to improve our profitability, we focus our efforts on improving operating efficiency. As reservoirs are depleted and production rates decline, per unit production costs will generally increase. To lessen this effect, we concentrate our production in core areas where we can achieve economies of scale to help manage our operating costs. Our drilling of high quality Marcellus wells has resulted in significantly lower direct operating expense on a per mcfe basis for 2013 when compared to 2012 and 2011.

Acquisitions

During 2013, we spent $137.5 million to acquire unproved acreage compared to $188.8 million in 2012 and $220.6 million in 2011. We continue selective acreage leasing and lease renewals to add to our acreage positions primarily in the Marcellus Shale play in Pennsylvania and the Mississippian play in Oklahoma and Kansas.

Divestitures and Discontinued Operations

Texas. In December 2012, we announced our plan to offer for sale certain of our Permian and Delaware Basin properties in West Texas and Southeast New Mexico. In February 2013, we announced we had signed a definitive agreement to sell these assets for a price of $275.0 million. We closed this disposition in April 2013 and we recorded a pre-tax gain of $79.1 million. During 2013, we sold miscellaneous unproved and proved property for proceeds of $33.5 million and we recorded a gain of $8.8 million. In March 2012, we sold 75% of a prospect in East Texas which included unproved properties and a suspended exploratory well to a third party for proceeds of $8.6 million and recorded a pre-tax loss of $10.9 million.

Texas-Discontinued Operations. In February 2011, we committed to a plan to sell substantially all of our Barnett Shale properties located in North Central Texas. While our Barnett properties did not meet held for sale criteria at December 31, 2010, the undiscounted cash flows for these properties were less than the carrying value so we recognized an impairment charge of $463.2 million in fourth quarter 2010. In April and August 2011, we sold these assets for gross cash proceeds of $889.3 million, including certain derivative contracts assumed by the buyer. The results of operations for these properties are reported as discontinued operations, net of tax for the year ended December 31, 2011. We recorded a pretax gain of $4.8 million in the year ended December 31, 2011 in discontinued operations related to this sale.

In December 2013, we announced our plan to offer for sale certain of our properties in the Permian Basin. These properties include approximately 90,000 (70,000 net) acres, almost all of which are held by production in Glasscock and Sterling Counties. The data room opened in January 2014 and we expect to receive bids in late February. However, the completion of the sale is dependent upon prospective buyer due diligence procedures and there can be no assurance the sale will be completed.

Southern Oklahoma. In November 2012, we sold certain oil and gas properties in Southern Oklahoma to a third party for gross proceeds of $135.0 million which resulted in a pretax gain of $55.2 million in the year ended December 31, 2012.

Pennsylvania. In September 2013, we sold our equity method investment in a drilling company for proceeds of $7.0 million and recognized a gain of $4.4 million. In June 2012, we sold a suspended exploratory well in the Marcellus Shale for proceeds of $2.5 million and recorded a pre-tax loss of $2.5 million on this transaction. In fourth quarter 2011, we exchanged unproved property in Ohio for unproved property in Pennsylvania where we received $11.5 million in cash as part of the transaction and recorded a pretax gain of $4.5 million in the year ended December 31, 2011. We recorded an additional $6.8 million gain related to this exchange in the year ended December 31, 2012.

2014 Outlook

For 2014, the board of directors approved a $1.52 billion capital budget for natural gas, NGLs, crude oil and condensate related activities, excluding proved property acquisitions, for which we do not budget. We expect to fund our 2014 capital budget expenditures with cash flows from operations, proceeds from asset sales and borrowings under our bank credit facility as necessary. As has been our historical practice, we will periodically review our capital expenditures throughout the year and adjust the budget based on commodity prices, drilling success and other factors. To the extent our capital requirements exceed our internally generated cash flow, proceeds from asset sales and our committed capacity under our bank credit facility, debt or equity may be issued to fund these requirements. The price risk on a portion of our forecasted natural gas, NGLs and oil production for 2014 is mitigated using commodity derivative contracts and we intend to continue to enter into these transactions. The prices we receive for our natural gas, NGLs and oil production are largely based on current market prices, which are beyond our control.

Market Conditions

Prices for various quantities of natural gas, NGLs and oil that we produce significantly impact our revenues and cash flows. Prices for commodities, such as hydrocarbons, are inherently volatile. The following table lists average NYMEX prices for natural gas and oil and the Mont Belvieu NGL composite price for the years ended December 31, 2013, 2012 and 2011.

	Year Ended December 31,		
	2013	2012	2011
Average NYMEX prices [a]			
Natural gas (per mcf)	$ 3.67	$ 2.82	$ 4.02
Oil (per bbl)	$ 98.20	$ 93.36	$ 95.24
Mont Belvieu NGL composite (per gallon)	$ 0.78	$ 0.89	$ 1.25

[a] Based on average of bid week prompt month prices.

Natural Gas, NGLs and Oil Sales, Production and Realized Price Calculations

Our revenues vary from year to year as a result of changes in realized commodity prices and production volumes. For more information, see “Source of our Revenues” above. In 2013, natural gas, NGLs and oil sales increased 27% from 2012 with a 25% increase in production and a 2% increase in realized prices. In 2012, natural gas, NGLs and oil sales increased 15% from 2011 with a 45% increase in production partially offset by a 21% decrease in realized prices. The following table illustrates the primary components of natural gas, NGLs, crude oil and condensate sales for each of the last three years (in thousands):

	2013	2012	2011
Natural gas, NGLs and oil sales			
Gas wellhead	$ 954,673	$ 612,354	$ 611,864
Gas hedges realized	110,948	238,259	123,595
Total gas revenue	$ 1,065,621	$ 850,613	$ 735,459
Total NGLs revenue	$ 315,272	$ 265,072	$ 268,846
Oil and condensate wellhead	$ 329,182	$ 237,963	$ 168,961
Oil hedges realized	5,601	(1,954)	—
Total oil and condensate revenue	$ 334,783	$ 236,009	$ 168,961
Combined wellhead	$ 1,599,127	$ 1,115,389	$ 1,049,671
Combined hedges	116,549	236,305	123,595
Total natural gas, NGLs and oil sales	$ 1,715,676	$ 1,351,694	$ 1,173,266

Our production continues to grow through drilling success as we place new wells on production and through additions from acquisitions partially offset by the natural decline of our natural gas and oil reserves through production and asset sales. For 2013, our production volumes increased 31% in our Appalachian region and decreased 4% in our Southwestern region when compared to 2012. For 2012, our production volumes increased 59% in our Appalachian region and increased 5% in our Southwestern region when compared to 2011. Our production for each of the last three years is set forth in the following table:

	2013	2012	2011
Production [(a)]			
Natural gas (mcf)	264,528,254	216,554,689	145,206,124
NGLs (bbls)	9,254,801	6,967,114	5,352,181
Crude oil and condensate (bbls)	3,827,491	2,851,312	1,959,608
Total (mcfe) [(b)]	343,022,006	275,465,245	189,076,858
Average daily production [(a)]			
Natural gas (mcf)	724,735	591,679	397,825
NGLs (bbls)	25,356	19,036	14,664
Crude oil and condensate (bbls)	10,486	7,790	5,369
Total (mcfe) [(b)]	939,786	752,637	518,019

(a) Represents volumes sold regardless of when produced.
(b) Oil and NGLs are converted to mcfe at the rate of one barrel equals six mcf based upon the approximate relative energy content of oil and natural gas, which is not necessarily indicative of the relationship of oil and natural gas prices.

Our average realized price (including all derivative settlements and third-party transportation costs) received during 2013 was $4.16 per mcfe compared to $4.35 per mcfe in 2012 and $5.68 per mcfe in 2011. Because we record transportation costs on two separate bases, as required by GAAP, we believe computed final realized prices should include the impact of transportation, gathering and compression expense. Our average realized price (including all derivative settlements and third-party transportation costs) calculation also includes all cash settlements for derivatives, whether or not they qualify for hedge accounting. Average sales prices (wellhead) do not include any derivative settlements or third party transportation costs which are reported in transportation, gathering and compression expense on the accompanying statements of operations. Average sales prices (wellhead) do include transportation costs where we receive net proceeds. Average realized price calculations for each of the last three years are shown below:

	2013	2012	2011
Average Prices			
Average sales prices (wellhead):			
Natural gas (per mcf)	$ 3.61	$ 2.83	$ 4.21
NGLs (per bbl)	34.07	38.05	50.23
Crude oil (per bbl)	86.00	83.46	86.22
Total (per mcfe) [(a)]	4.66	4.05	5.55
Average realized prices (including derivative settlements that qualified for hedge accounting):			
Natural gas (per mcf)	$ 4.03	$ 3.93	$ 5.06
NGLs (per bbl)	34.07	38.05	50.23
Crude oil (per bbl)	87.47	82.77	86.22
Total (per mcfe) [(a)]	5.00	4.91	6.21
Average realized prices (including all derivative settlements):			
Natural gas (per mcf)	$ 4.00	$ 3.95	$ 5.22
NGLs (per bbl)	32.71	42.60	52.03
Crude oil (per bbl)	84.70	83.64	81.34
Total (per mcfe) [(a)]	4.91	5.05	6.32
Average realized prices (including all derivative settlements and third party transportation costs paid by Range):			
Natural gas (per mcf)	$ 3.08	$ 3.11	$ 4.43
NGLs (per bbl)	31.29	41.03	50.82
Crude oil (per bbl)	84.70	83.64	81.34
Total (per mcfe) [(a)]	4.16	4.35	5.68

[(a)] Oil and NGLs are converted at the rate of one barrel equals six mcf based upon the approximate relative energy content of oil to natural gas, which is not indicative of the relationship of oil and natural gas prices.

Derivative fair value (loss) income was a loss of $61.8 million in 2013 compared to income of $41.4 million in 2012 and income of $40.1 million in 2011. Through February 28, 2013, some of our derivatives did not qualify for hedge accounting and were accounted for using the mark-to-market accounting method whereby all realized and unrealized gains or losses related to these contracts were included in derivative fair value income or loss. Effective March 1, 2013, we discontinued hedge accounting prospectively. Since March 1, 2013, all of our derivatives are accounted for using the mark-to-market accounting method. Mark-to-market accounting treatment creates volatility in our revenues as unrealized gains and losses from derivatives are included in total revenues. As commodity prices increase or decrease, such changes will have an opposite effect on the mark-to-market value of our derivatives. Gains on our derivatives generally indicate lower wellhead revenues in the future while losses indicate higher future wellhead revenues. At December 31, 2013, all of our derivative contracts were recorded at their fair value, which was a pre-tax loss of $16.5 million, a decrease of $160.8 million from the $144.3 million net asset recorded as of December 31, 2012. We have also entered into basis swap agreements to limit volatility caused by changing differentials between index and regional prices received. These basis swaps are marked to market and were recognized as a pre-tax gain of $3.9 million as of December 31, 2013.

Brokered natural gas, marketing and other revenue was $116.6 million in 2013 compared to $15.4 million in 2012 and $15.0 million in 2011. The 2013 period includes revenue from marketing and sale of brokered gas of $118.3 million. These revenues increased significantly from prior years due to an increase in the purchase (and sale) of natural gas which was used to blend our rich residue gas from the Southwest Marcellus Shale of $62.8 million and an increase in brokered natural gas transactions. The 2012 period includes revenue from marketing and the sale of brokered gas of $15.1 million. The 2011 period includes revenue from marketing and the sale of brokered gas of $12.7 million, proceeds from a lawsuit settlement and other income partially offset by a loss from equity method investments of $1.0 million.

Costs and Expenses

We believe some of our expense fluctuations are best analyzed on a unit-of-production, or per mcfe, basis. The following presents information about certain of our expenses on a per mcfe basis for each of the last three years:

	Year Ended December 31,				Year Ended December 31,			
	2013	2012	Change	% Change	2012	2011	Change	% Change
Direct operating expense	$ 0.37	$ 0.42	$ (0.05)	(12%)	$ 0.42	$ 0.60	$ (0.18)	(30%)
Production and ad valorem tax expense	0.13	0.24	(0.11)	(46%)	0.24	0.15	0.09	60%
General and administrative expense	0.85	0.63	0.22	35%	0.63	0.80	(0.17)	(21%)
Interest expense	0.51	0.61	(0.10)	(16%)	0.61	0.66	(0.05)	(8%)
Depletion, depreciation and amortization expense	1.44	1.62	(0.18)	(11%)	1.62	1.80	(0.18)	(10%)

Direct operating expense was $128.1 million in 2013 compared to $115.9 million in 2012 and $113.0 million in 2011. We experience increases in operating expenses as we add new wells and manage existing properties. Direct operating expenses include normally recurring expenses to operate and produce our wells, non-recurring workovers and repairs. On an absolute basis, our direct operating expense for 2013 increased 11% from the same period of the prior year with an increase in producing wells, higher workover costs, utilities, personnel costs, well insurance, water hauling and nitrogen injection costs somewhat offset by the sale of certain non-core assets at the beginning of second quarter 2013. On an absolute basis, our spending for direct operating expenses for 2012 increased 3% from the same period of the prior year with an increase in producing wells offset by lower costs for water hauling and disposal, equipment rental and well services. We incurred $8.6 million of workover costs in 2013 compared to $4.8 million of workover costs in 2012 and $3.6 million in 2011.

On a per mcfe basis, operating expense for 2013 decreased $0.05 or 12% from the same period of 2012, with the decrease consisting of lower costs for personnel and well services. On a per mcfe basis, operating expense for 2012 decreased $0.18 or 30% from the same period of 2011, with the decrease consisting of lower costs for well services and personnel costs. We expect to continue to experience lower costs per mcfe as we increase production from our Marcellus Shale wells due to their lower operating cost relative to our other operating areas somewhat offset by higher operating costs on our liquids-rich wells. Operating costs in the Mississippian play are higher on a per mcfe basis than the Marcellus Shale play. Stock-based compensation expense represents the amortization of restricted stock as part of the compensation of field employees. The following table summarizes direct operating expenses per mcfe for each of the last three years:

	Year Ended December 31,				Year Ended December 31,			
	2013	2012	Change	% Change	2012	2011	Change	% Change
Lease operating expense	$ 0.34	$ 0.39	$ (0.05)	(13%)	$ 0.39	$ 0.57	$ (0.18)	(32%)
Workovers	0.02	0.02	—	—	0.02	0.02	—	—
Stock-based compensation (non-cash)	0.01	0.01	—	—	0.01	0.01	—	—
Total direct operating expenses	$ 0.37	$ 0.42	$ (0.05)	(12%)	$ 0.42	$ 0.60	$ (0.18)	(30%)

Production and ad valorem taxes are paid based on market prices, not hedged prices. This expense category also includes the Pennsylvania impact fee. In February 2012, the Commonwealth of Pennsylvania enacted an “impact fee” on unconventional natural gas and oil production which includes the Marcellus Shale. The year ended December 31, 2013 includes $28.0 million ($0.08 per mcfe) impact fee. The year ended December 31, 2012 includes a $25.2 million ($0.09 per mcfe) retroactive impact fee which covers all wells drilled prior to 2012 and was paid in September 2012. Also included in the year ended December 31, 2012 is a $24.0 million ($0.09 per mcfe) impact fee for wells drilled prior to 2012 and wells drilled in 2012 which was paid in April 2013. Production and ad valorem taxes (excluding the impact fee) were $17.2 million in 2013 compared to $17.9 million in 2012 and $27.7 million in 2011. On a per mcfe basis, production and ad valorem taxes (excluding the impact fee) decreased to $0.05 in 2013 compared to $0.06 in 2012 due to an increase in production volumes not subject to production or ad valorem taxes. On a per mcfe basis, production and ad valorem taxes decreased to $0.06 in 2012 from $0.15 in 2011 due to an increase in production volumes not subject to production or ad valorem taxes.

General and administrative expense was $291.2 million for 2013 compared to $173.8 million for 2012 and $151.2 million in 2011. The 2013 increase of $117.4 million when compared to 2012 is primarily due to a legal settlement related to an Oklahoma lawsuit of $87.5 million, higher salary and benefit expenses of $9.5 million, an increase in stock-based compensation of $11.2 million which includes additional expense of $10.0 million related to the acceleration of stock-based compensation for our executive chairman who became a non-employee director on January 1, 2014, and higher legal, office and other expenses. The 2012 increase of $22.6 million when compared to 2011 is due to higher salaries and benefits of $11.0 million, an increase in stock-based compensation of $8.3 million and higher legal and office expenses, including information technology. Our number of general and administrative employees increased 3% during 2013. Our personnel costs continue to increase as we invest in our technical teams and other staffing to support our expansion into the Marcellus Shale in Appalachia and the Mississippian play in Oklahoma. Stock-based compensation expense represents the amortization of restricted stock grants and SARs granted to our employees and directors as part of their compensation. The following table summarizes general and administrative expenses per mcfe for each of the last three years:

	Year Ended December 31,				Year Ended December 31,			
	2013	2012	Change	% Change	2012	2011	Change	% Change
General and administrative	$ 0.43	$ 0.47	$ (0.04)	(9%)	$ 0.47	$ 0.61	$ (0.14)	(23%)
Oklahoma legal settlement	0.26	—	0.26	—	—	—	—	—
Stock-based compensation (non-cash)	0.16	0.16	—	—	0.16	0.19	(0.03)	(16%)
Total general and administrative expenses	$ 0.85	$ 0.63	$ 0.22	35%	$ 0.63	$ 0.80	$ (0.17)	(21%)

Interest expense was $176.6 million for 2013 compared to $168.8 million for 2012 and $125.1 million in 2011. The following table presents information about interest expense for each of the years in the three-year period ended December 31, 2013 (in thousands):

	2013	2012	2011
Bank credit facility	$ 13,723	$ 11,822	$ 8,856
Subordinated notes	152,071	147,552	123,721
Other	10,763	9,424	7,266
Allocated to discontinued operations	—	—	(14,791)
Total interest expense	$ 176,557	$ 168,798	$ 125,052

The increase in interest expense for 2013 from the same period of 2012 was primarily due to an increase in outstanding debt balances partially offset by lower interest rates. The increase in interest expense for 2012 from the same period of 2011 was due to higher interest rates and outstanding debt balances. In March 2013, we issued $750.0 million of 5.0% senior subordinated notes due 2023. We used the proceeds for general corporate purposes and to retire outstanding balances on our bank debt which carries a lower interest rate. In May 2013, we redeemed $250.0 million of our 7.25% senior subordinated notes due 2018. In March 2012, we issued $600.0 million of 5.0% senior subordinated notes due 2022. We used the proceeds for general corporate purposes and to retire outstanding balances on our bank debt. In May 2011, we issued $500.0 million of 5.75% senior subordinated notes due 2021. We used the proceeds for general corporate purposes and to purchase or redeem $150.0 million of our 6.375% senior subordinated notes due 2015 and $250.0 million of our 7.5% senior subordinated notes due 2016. The 2013, 2012 and 2011 note issuances were undertaken to better match the maturities of our debt with the life of our properties and to give us greater liquidity for the near term. Average debt outstanding on the bank credit facility for 2013 was $441.0 million compared to $308.0 million for 2012 and $175.6 million for 2011 and the weighted average interest rate on the bank credit facility was 2.0% for 2013 compared to 2.2% in each of the years ended December 31, 2012 and 2011.

Depletion, depreciation and amortization ("DD&A") was $492.4 million in 2013 compared to $445.2 million in 2012 and $341.2 million in 2011. The increase in 2013 when compared to 2012 is due to a 11% decrease in depletion rates more than offset by a 25% increase in production. The increase in 2012 when compared to 2011 is due to a 9% decrease in depletion rates more than offset by a 45% increase in production.

On a per mcfe basis, DD&A decreased to $1.44 in 2013 compared to $1.62 in 2012 and $1.80 in 2011. Depletion expense, the largest component of DD&A, was $1.37 per mcfe in 2013 compared to $1.54 per mcfe in 2012 and $1.69 per mcfe in 2011. We have historically adjusted our depletion rates in the fourth quarter of each year based on the year-end reserve report and other times during the year when circumstances indicate there has been a significant change in reserves or costs. We currently expect our DD&A rate to be approximately $1.40 per mcfe in 2014, based on our current production estimates. In areas where we are actively drilling, such as the Marcellus area, our fourth quarter adjusted 2013 depletion rates were lower than the fourth quarter 2012 and 2011 depletion rates. Depletion rates in new plays tend to be higher in the beginning as increased initial outlays are amortized over proved reserves based on early stages of evaluations. The decrease in the DD&A per mcfe in 2013 when compared to 2012 is due to the mix of our production. The decrease in the DD&A per mcfe in 2012 when compared to 2011 is due to lower depreciation expense and the mix of our production. The following table summarizes DD&A expenses per mcfe for each of the last three years:

	Year Ended December 31,				Year Ended December 31,			
	2013	2012	Change	% Change	2012	2011	Change	% Change
Depletion and amortization	$ 1.37	$ 1.54	$ (0.17)	(11%)	$ 1.54	$ 1.69	$ (0.15)	(9%)
Depreciation	0.04	0.05	(0.01)	(20%)	0.05	0.08	(0.03)	(38%)
Accretion and other	0.03	0.03	—	—	0.03	0.03	—	—
Total DD&A expenses	$ 1.44	$ 1.62	$ (0.18)	(11%)	$ 1.62	$ 1.80	$ (0.18)	(10%)

Other Operating Expenses

Our total operating expenses also include other expenses that generally do not trend with production. These expenses include stock-based compensation, transportation, gathering and compression, brokered natural gas and marketing, exploration expense, abandonment and impairment of unproved properties, deferred compensation plan expenses, loss on early extinguishment of debt and impairment of proved properties.

The following table details stock-based compensation that is allocated to functional expense categories for each of the years in the three-year period ended December 31, 2013 (in thousands):

	2013	2012	2011
Direct operating expense	$ 2,755	$ 2,415	$ 1,987
Brokered natural gas and marketing expense	1,852	1,765	1,455
Exploration expense	4,025	4,049	4,108
General and administrative expense	55,737	44,541	36,244
Total stock-based compensation	$ 64,369	$ 52,770	$ 43,794

Stock-based compensation includes the amortization of restricted stock grants and SARs grants. This amortization increased from 2012 to 2013 primarily due to an additional expense of $10.0 million related to the acceleration of stock-based compensation for our executive chairman who became a non-employee director on January 1, 2014. This amortization increased from 2011 to 2012 due to accelerated expense for employee retirements and an increase in our employee base and their allocated stock-based compensation grants.

Transportation, gathering and compression expense was $256.2 million in 2013 compared to $192.4 million in 2012 and $120.8 million in 2011. These third party costs are higher in each year due to our production growth in the Marcellus Shale where we have third party gathering, compression and transportation agreements. We have included these costs in the calculation of average realized prices (including all derivative settlements and third party transportation expenses paid by Range).

Brokered natural gas and marketing was $131.8 million in 2013 compared to $20.4 million in 2012 and $12.0 million in 2011. The increase in 2013 from 2012 is due to a $69.8 million increase in the purchase (and sale) of natural gas which was used to blend our residue gas from the Southwest Marcellus Shale, an increase in our marketing staff personnel expenses and an increase in brokered gas transactions. The increase in 2012 from 2011 is primarily due to an increase in brokered natural gas purchases. Stock-based compensation included here represents the amortization of restricted stock and SARs as part of the compensation of our marketing staff.

Exploration expense was $64.4 million in 2013 compared to $69.8 million in 2012 and $81.4 million in 2011. Exploration expense was lower in 2013 when compared to 2012 due to lower seismic and delay rental costs partially offset by higher dry hole costs. Exploration expense was lower in 2012 when compared to 2011 due to lower seismic and dry hole costs. Stock-based compensation represents the amortization of restricted stock and SARs as part of the compensation of our exploration staff. The following table details our exploration related expenses for each of the years in the three-year period ended December 31, 2013 (in thousands):

	Year Ended December 31,				Year Ended December 31,			
	2013	2012	Change	% Change	2012	2011	Change	% Change
Seismic	$ 26,872	$ 33,462	$ (6,590)	(20%)	$ 33,462	$ 40,672	$ (7,210)	(18%)
Delay rentals and other	12,969	18,286	(5,317)	(29%)	18,286	19,282	(996)	(5%)
Personnel expense	14,844	13,168	1,676	13%	13,168	13,417	(249)	(2%)
Stock-based compensation expense	4,025	4,049	(24)	(1%)	4,049	4,108	(59)	(1%)
Exploratory dry hole expense	5,699	842	4,857	577%	842	3,888	(3,046)	(78%)
Total exploration expense	$ 64,409	$ 69,807	$ (5,398)	(8%)	$ 69,807	$ 81,367	$ (11,560)	(14%)

Abandonment and impairment of unproved properties was $51.9 million in 2013 compared to $125.3 million in 2012 and $79.7 million in 2011. We assess individually significant unproved properties for impairment on a quarterly basis and recognize a loss where circumstances indicate impairment in value. In determining whether a significant unproved property is impaired we consider numerous factors including, but not limited to, current exploration plans, favorable or unfavorable activity on the property being evaluated and/or adjacent properties, our geologists' evaluation of the property and the remaining months in the lease term for the property. Impairment of individually insignificant unproved properties is assessed and amortized on an aggregate basis based on our average holding period, expected forfeiture rate and anticipated drilling success. As we continue to review our acreage positions and high grade our drilling inventory based on the current price environment, additional leasehold impairments and abandonments will likely be recorded. In second quarter 2013, we impaired individually significant unproved properties in East Texas for $5.4 million. In third quarter 2012, we impaired individually significant unproved properties in the Barnett Shale of North Texas (the last of our unproved properties in the area) for $19.6 million because we chose to not develop the acreage. Also, due to an unproved property transaction in second quarter 2012, we impaired individually significant unproved properties in Pennsylvania for $23.1 million because we will not drill in these areas.

Deferred compensation plan expense was $55.3 million in 2013 compared to $7.2 million in 2012 and $43.2 million in 2011. Our stock price increased to $84.31 at December 31, 2013 compared to $62.83 at December 31, 2012. Our stock price increased to $62.83 at December 31, 2012 compared to $61.94 at December 31, 2011. This non-cash item relates to the increase or decrease in value of the liability associated with our common stock that is vested and held in our deferred compensation plan. The deferred compensation liability is adjusted to fair value by a charge or a credit to deferred compensation plan expense. Common shares are placed in the deferred compensation plan when granted.

Loss on early extinguishment of debt was $12.3 million in 2013 compared to $11.1 million in 2012 and $18.6 million in 2011. In May 2013, we redeemed all of our $250.0 million aggregate principal amount of our 7.25% senior subordinated notes due 2018 at 103.625% of par and we recorded a loss on extinguishment of debt of $12.3 million which includes a call premium and the expensing of related deferred financing costs on the repurchased debt. In December 2012, we redeemed our 7.5% senior subordinated notes due 2017 at a redemption price equal to 103.75%. We recorded a loss on extinguishment of debt of $11.1 million including call premium costs of $9.4 million and expensing of related deferred financing costs on the redeemed debt. In May and June 2011, we purchased or redeemed our 6.375% senior subordinated notes due 2015 at a price equal to 102.31% and we purchased or redeemed our 7.5% senior subordinated notes due 2016 at a price equal to 103.95%. We recorded a loss on early extinguishment of debt of $18.6 million, which includes a call premium and other consideration of $13.3 million and expensing of related deferred financing costs on the repurchased debt.

Impairment of proved properties decreased to $7.8 million in 2013 compared to $35.6 million in 2012 and $38.7 million in 2011. The year ended December 31, 2013 includes $7.0 million impairment related to certain South Texas wells. The year ended December 31, 2013 also includes $741,000 impairment expense related to surface acreage in North Texas. The year ended 2012 includes $31.1 million impairment related to our properties in Mississippi, $3.2 million related to our remaining North Texas assets and $1.3 million related to surface acreage, also in North Texas. The year ended 2011 includes $31.2 million impairment related to our East Texas properties and $7.5 million related to our Gulf Coast onshore properties. Our analysis of these properties determined that undiscounted cash flows were less than their carrying value. We compared the carrying value to estimated fair value and recognized an impairment charge. These assets were evaluated for impairment due to declining reserves and natural gas prices and, in the case of certain of our North Texas and East Texas properties, the possibility of a sale.

Income tax expense was \$33.9 million compared to \$12.1 million in 2012 and \$35.6 million in 2011. The 2013 increase in income taxes reflects a 497% increase in income from continuing operations when compared to the same period of 2012. The 2012 decrease in income taxes reflects a 68% decrease in income from continuing operations when compared to the same period of 2011. The effective tax rate was 22.6% in 2013 compared to 48.1% in 2012 and 45.4% in 2011. For the year ended December 31, 2013, the current income tax benefit of \$143,000 is related to a refund of state income taxes. For the year ended December 31, 2012 the current income tax benefit of \$1.8 million is related to state income taxes and includes favorable adjustments to reflect state income tax returns as filed. For the year ended December 31, 2011, the current income tax expense of \$637,000 is related to state income taxes. The 2013, 2012 and 2011 effective tax rate was different than the statutory tax rate due to state income taxes, and in 2013 and 2012, our tax rates were also affected by an increase in our valuation allowance related to the deferred tax asset for future deferred compensation plan distributions of senior executives to the extent their estimated future compensation (including these distributions) would exceed the \$1.0 million deductible limit provided under Section 162(m) of the Internal Revenue Code. Our effective tax rates are also impacted by adjustments to our state apportionment rates which was a benefit of \$21.2 million in 2013 compared to a benefit of \$736,000 in 2012 and a benefit of \$3.9 million in 2011. For 2012, our effective tax rate was impacted by a \$2.0 million valuation allowance related to our Pennsylvania state net operating loss carryforwards. This valuation allowance was increased to \$3.0 million in 2013. We expect our effective tax rate to be approximately 38% for 2014, before any discrete tax items.

Discontinued operations include the operating results and impairment losses related to our Barnett properties. Substantially all of these properties were sold in April 2011 for proceeds of \$889.3 million including certain derivatives assumed by the buyer and we recorded a gain of \$4.8 million on the sale. See Note 4 to our accompanying consolidated financial statements. Interest expense is allocated to discontinued operations based on the ratio of net assets of discontinued operations to our consolidated net assets plus long-term debt.

Management's Discussion and Analysis of Financial Condition, Cash Flows, Capital Resources and Liquidity

Cash Flows

Cash flows from operations are primarily affected by production volumes and commodity prices, net of the effects of settlements of our derivatives. Our cash flows from operations also are impacted by changes in working capital. We generally maintain low cash and cash equivalent balances because we use available funds to reduce our bank debt. Short-term liquidity needs are satisfied by borrowings under our bank credit facility. Because of this, and since our principal source of operating cash flows (proved reserves to be produced in the following year) cannot be reported as working capital, we often have low or negative working capital. We sell a large portion of our production at the wellhead under floating market contracts. From time to time, we enter into various derivative contracts to provide an economic hedge of our exposure to commodity price risk associated with anticipated future natural gas, NGLs and oil production. The production we hedge has and will continue to vary from year to year depending on, among other things, our expectation of future commodity prices. As of December 31, 2013, we have hedged approximately 80% of our projected 2014 production. Any payments due to counterparties under our derivative contracts should ultimately be funded by prices received from the sale of our production. Production receipts, however, often lag payments to the counterparties. Any interim cash needs are funded by borrowings under the bank credit facility. As of December 31, 2013, we have entered into hedging agreements covering 299.3 Bcfe for 2014, 118.2 Bcfe for 2015 and 7.3 Bcfe for 2016.

Net cash provided from continuing operations in 2013 was \$743.5 million compared to \$647.1 million in 2012 and \$610.2 million in 2011. The increase in cash provided from operating activities from 2012 to 2013 reflects a 25% increase in production somewhat offset by lower realized prices (a decline of 4%) and higher operating costs. The increase in cash provided from operating activities from 2011 to 2012 reflects a 45% increase in production somewhat offset by lower realized prices (a decline of 23%) and higher operating costs. Net cash provided from continuing operations is also affected by working capital changes or the timing of cash receipts and disbursements. Changes in working capital (as reflected in our consolidated statements of cash flows) for 2013 was a negative \$42.8 million compared to a negative \$24.5 million for 2012 and negative \$41.0 million in 2011. The changes in negative working capital for all three years is primarily due to the impact fee accrual.

Net cash provided from discontinued operations was \$21.4 million in 2011. Discontinued operations is related to the sale of our Barnett Shale properties which were sold in April 2011 with a February 1, 2011 effective date.

Net cash used in investing activities from continuing operations in 2013 was \$983.4 million compared to \$1.5 billion in 2012 and \$1.4 billion in 2011.

During 2013, we:

- spent \$1.2 billion on natural gas and oil property additions associated with our drilling and completion capital budget program;
- spent \$132.1 million on acreage, primarily in the Marcellus Shale; and
- received proceeds of \$315.5 million which includes \$275.0 million from the sale of our Southeast New Mexico and certain West Texas properties.

During 2012, we:

- spent $1.5 billion on natural gas and oil property additions associated with our drilling and completion capital budget program;
- spent $191.1 million on acreage, primarily in the Marcellus Shale and the Mississippian; and
- received proceeds of $168.2 million which includes $135.0 million from the sale of our Ardmore Woodford properties in Southern Oklahoma.

During 2011, we:

- spent $1.2 billion on natural gas and oil property additions associated with our drilling and completion capital budget program;
- spent $226.5 million on acreage, primarily in the Marcellus Shale; and
- received proceeds of $53.9 million primarily related to the sale of a low-pressure pipeline and various proved and unproved properties.

Net cash provided from (used in) investing activities from discontinued operations for 2011 was an increase of $840.7 million. In 2011, we received proceeds of $849.3 million from the sale of our Barnett Shale assets.

Net cash provided from (used in) financing activities in 2013 was an increase of $240.0 million compared to an increase of $881.6 million in 2012 and a decrease of $86.4 million in 2011. Historically, sources of financing have been primarily bank borrowings and capital raised through debt offerings.

During 2013, we:

- borrowed $1.7 billion and repaid $1.9 billion under our credit facility, ending the year with $239.0 million lower bank debt;
- issued $750.0 million aggregate principal amount of 5.0% senior subordinated notes due 2023; and
- redeemed all $250.0 million aggregate principal amount of 7.25% senior subordinated notes due 2018 and paid additional expenses related to the early extinguishment.

During 2012, we:

- borrowed $1.8 billion and repaid $1.2 billion under our bank credit facility, ending the year with $552.0 million higher bank debt;
- issued $600.0 million aggregate principal amount of 5.0% senior subordinated notes due 2022; and
- redeemed all $250.0 million aggregate principal amount of 7.5% senior subordinated notes due 2017 and paid additional expenses related to the early extinguishment.

During 2011, we:

- borrowed $887.8 million and repaid $974.8 million under our bank credit facility; ending the year with $87.0 million lower bank debt;
- issued $500.0 million aggregate principal amount of 5.75% senior subordinated notes due 2021; and
- used some of the proceeds from the sale of the 5.75% senior subordinated notes to purchase or redeem all $150.0 million aggregate principal amount of 6.375% senior subordinated notes due 2015 and $250.0 million aggregate principal amount of 7.5% senior subordinated notes due 2016 including related expenses.

Liquidity and Capital Resources

Our main sources of liquidity and capital resources are internally generated cash flow from operations, a bank credit facility with uncommitted and committed availability, asset sales and access to the debt and equity capital markets. We must find new and develop existing reserves to maintain and grow our production and cash flows. We accomplish this primarily through successful drilling programs which require substantial capital expenditures. Lower prices for natural gas, NGLs and oil may reduce the amount of natural gas, NGLs and oil we can economically produce and can also affect the amount of cash flow available for capital expenditures and our ability to borrow or raise additional capital.

We currently believe that net cash generated from operating activities, unused committed borrowing capacity under our bank credit facility and proceeds from asset sales combined with our natural gas, NGLs and oil derivatives currently in place will be adequate to satisfy near-term financial obligations and liquidity needs. To the extent our capital requirements exceed our internally generated cash flow and proceeds from asset sales, debt or equity may be issued to fund these requirements. Long-term cash flows are subject to a number of variables including the level of production and prices as well as various economic conditions that have historically affected the natural gas and oil business. We establish a capital budget at the beginning of each calendar year and review it during the course of the year. Our 2014 capital budget is $1.52 billion. Actual capital expenditure levels may vary significantly due to many factors, including drilling results, natural gas, NGLs, crude oil and condensate prices, industry conditions, the prices and availability of goods and services, the extent to which properties are acquired or non-strategic assets sold.

During 2013, we:

- received proceeds from the sale of non-strategic assets of $315.5 million;
- issued $750.0 million aggregate principal of 5% senior subordinated notes due 2023; and
- repurchased all $250.0 million aggregate principle amount of 7.25% senior subordinated notes due 2018.

As of December 31, 2013, we had available borrowing capacity of $1.2 billion under our bank credit facility. In December 2013, we announced our plan to offer for sale certain of our properties in the Permian Basin. These properties include approximately 90,000 (70,000 net) acres, almost all of which are held by production in Glasscock and Sterling Counties. The data room opened in January 2014 and we expect to receive bids in late February. However, the completion of the sale is dependent upon prospective buyer due diligence procedures and there can be no assurance the sale will be completed.

Credit Arrangements

Long-term debt at December 31, 2013 totaled $3.1 billion, including $500.0 million of bank credit facility debt and $2.6 billion of senior subordinated notes. Our committed borrowing capacity at December 31, 2013 was $1.75 billion. As of December 31, 2013, we maintained a $2.0 billion bank credit facility, which we refer to as our bank credit facility. As of December 31, 2013, we also have $84.9 million of undrawn letters of credit. The bank credit facility is secured by substantially all of our assets and has a maturity date of February 18, 2016. Availability under the bank credit facility is subject to a borrowing base set by the lenders semi-annually with an option to set more often in certain circumstances. The borrowing base is dependent on a number of factors but primarily the lenders' assessments of future cash flows. Redeterminations of the borrowing base require approval of two thirds of the lenders; increases require 97% approval.

Our bank credit facility and our subordinated notes impose limitations on the payment of dividends and other restricted payments (as defined under the debt agreements for our bank debt and our subordinated notes). The debt agreements also contain customary covenants relating to debt incurrence, working capital, dividends and financial ratios. We were in compliance with all covenants at December 31, 2013.

Proved Reserves

To maintain and grow production and cash flow, we must continue to develop existing proved reserves and locate or acquire new natural gas, NGLs and oil reserves. The following is a discussion of proved reserves, reserve additions and revisions and future net cash flows from proved reserves.

	Year End December 31,		
	2013	2012	2011
Proved Reserves:			
Beginning of year	6,505,570	5,053,961	4,442,290
Reserve additions	1,732,944	1,767,202	1,493,357
Reserve revisions	448,898	109,036	224,542
Purchases	—	—	—
Sales	(142,116)	(149,153)	(903,983)
Production	(343,022)	(275,476)	(202,245)
End of year	8,202,274	6,505,570	5,053,961
Proved Developed Reserves:			
Beginning of year	3,457,502	2,401,274	2,183,488
End of year	4,192,666	3,457,502	2,401,274

Our proved reserves at year-end 2013 were 8.2 Tcfe compared to 6.5 Tcfe at year-end 2012 and 5.1 Tcfe at year-end 2011. Natural gas comprised approximately 69%, 74% and 79% of our proved reserves at year-end 2013, 2012 and 2011.

Reserve Additions and Revisions. During 2013, we added 1.7 Tcfe of proved reserves from drilling activities and evaluation of proved areas, primarily in the Marcellus Shale. Approximately 49% of the 2013 reserve additions were attributable to natural gas. Revisions of previous estimates of 449 Bcfe for the year ended December 31, 2013 consist of positive performance revisions, positive price revisions and improved recovery, partially offset by reserves reclassified to unproved because of a slower pace of development activity beyond the five-year development horizon. We added 369 Bcfe of incremental ethane reserves under additional ethane contracts in Appalachia.

During 2012, we added 1.8 Tcfe of proved reserves from drilling activities and evaluations of proved areas, primarily in the Marcellus Shale. Approximately 56% of the 2012 reserve additions were attributable to natural gas. We added 307 Bcfe (or 17% of the 2012 reserve additions) of incremental ethane reserves in Appalachia (51.2 Mmbls) as part of NGLs proved reserves associated with initial ethane deliveries under contracts commencing in 2013. Revisions of previous estimates of 109 Bcfe for the year ended December 31, 2012 consists of positive performance revisions for our properties somewhat offset by negative pricing revisions and reserves reclassified to unproved because of a slower pace of development activity beyond the five-year development horizon.

During 2011, we added approximately 1.5 Tcfe of proved reserves from drilling activities and evaluations of proved areas, primarily in the Marcellus Shale. Approximately 87% of the 2011 reserve additions were attributable to natural gas. Revisions of previous estimates of 225 Bcfe for the year ended December 31, 2011 were primarily positive performance revisions for natural gas properties, primarily in the Marcellus Shale.

Sales. In 2013, we sold 142.1 Bcfe of reserves related to the sale of certain of our Permian Basin and New Mexico properties. In 2012, we sold approximately 149.2 Bcfe of reserves primarily related to the sale of our Ardmore Woodford properties in Southern Oklahoma. In 2011, we sold approximately 904.0 Bcfe of reserves primarily related to the sale of our Barnett properties.

Future Net Cash Flows. At December 31, 2013, the present value (discounted at 10%) of estimated future net cash flows from our proved reserves was $7.9 billion. The present value of our estimated future net cash flows at December 31, 2012 was $4.0 billion. This present value was calculated based on the unweighted average first-day-of-the-month oil and gas prices for the prior twelve months held flat for the life of the reserves. At December 31, 2013, the after tax present value of estimated future net cash flows from our proved reserves was $5.9 billion compared to $3.2 billion at December 31, 2012.

The present value of future net cash flows does not purport to be an estimate of the fair market value of our proved reserves. An estimate of fair value would also take into account, among other things, anticipated changes in future prices and costs, the expected recovery of reserves in excess of proved reserves and a discount factor more representative of the time value of money to the evaluating party and the perceived risks inherent in producing oil and gas.

Capitalization and Dividend Payments

As of December 31, 2013 and 2012, our total debt and capitalization were as follows (in thousands):

	2013	2012
Bank debt	$ 500,000	$ 739,000
Senior subordinated notes	2,640,515	2,139,185
Total debt	3,140,515	2,878,185
Stockholders' equity	2,414,452	2,357,392
Total capitalization	$ 5,554,967	$ 5,235,577
Debt to capitalization ratio	56.5%	55.0%

The amount of future dividends is subject to declaration by the board of directors and primarily depends on earnings, capital expenditures and various other factors. In 2013, we paid $26.1 million in dividends to our common shareholders ($0.04 per share each quarter). In 2012, we paid $26.0 million in dividends to our common shareholders ($0.04 per share each quarter). In 2011, we paid $25.8 million in dividends to our common shareholders ($0.04 per share each quarter).

Cash Contractual Obligations

Our contractual obligations include long-term debt, operating leases, drilling commitments, derivative obligations, asset retirement obligations and transportation and gathering commitments. As of December 31, 2013, we do not have any capital leases or any significant off-balance sheet debt or other such unrecorded obligations and we have not guaranteed any debt of any unrelated party. As of December 31, 2013, we had a total of $84.9 million of letters of credit outstanding under our bank credit facility. The table below provides estimates of the timing of future payments that we are obligated to make based on agreements in place at December 31, 2013. In addition to the contractual obligations listed on the table below, our balance sheet at December 31, 2013 reflects accrued interest payable on our bank debt of $2.5 million which is payable in first quarter 2014. We expect to make interest payments of $24.0 million per year on our 8.0% senior subordinated notes, $33.8 million per year on our 6.75% senior subordinated notes, $28.8 million per year on our 5.75% senior subordinated notes and $67.5 million per year on our 5.0% senior subordinated notes.

The following summarizes our contractual financial obligations at December 31, 2013 and their future maturities. We expect to fund these contractual obligations with cash generated from operating activities, borrowings under our bank credit facility, additional debt issuances and proceeds from asset sales (in thousands).

	Payment due by period					
	2014	2015	2016	2017 and 2018	Thereafter	Total
Bank debt due 2016 [(a)]	$ —	$ —	$ 500,000	$ —	$ —	$ 500,000
8.0% senior subordinated notes due 2019	—	—	—	—	300,000	300,000
6.75% senior subordinated notes due 2020	—	—	—	—	500,000	500,000
5.75% senior subordinated notes due 2021	—	—	—	—	500,000	500,000
5.0% senior subordinated notes due 2022	—	—	—	—	600,000	600,000
5.0% senior subordinated notes due 2023	—	—	—	—	750,000	750,000
Operating leases	19,946	19,170	12,434	12,455	17,230	81,235
Drilling rig commitments	8,984	6,745	—	—	—	15,729
Transportation and gathering commitments	227,061	238,148	261,854	486,548	1,363,537	2,577,148
Hydraulic fracturing services	24,000	12,000	—	—	—	36,000
Seismic agreements	10,646	838	—	—	—	11,484
Other purchase obligations	280	199	—	—	—	479
Derivative obligations [(b)]	26,198	25	—	—	—	26,223
Asset retirement obligation liability [(c)]	5,037	9,235	7,371	16,470	191,964	230,077
Total contractual obligations [(d)]	$ 322,152	$ 286,360	$ 781,659	$ 515,473	$ 4,222,731	$ 6,128,375

(a) Due at termination date of our bank credit facility. Interest paid on our bank credit facility would be approximately $9.1 million each year assuming no change in the interest rate or outstanding balance.

(b) Derivative obligations represent net open derivative contract liabilities valued as of December 31, 2013. While such payments will be funded by higher prices received from the sale of our production, production receipts may be received after our payments to counterparties, which can result in borrowings under our bank credit facility.

(c) The ultimate settlement amount and timing cannot be precisely determined in advance. See Note 9 to our consolidated financial statements.

(d) This table excludes the liability for the deferred compensation plans since these obligations will be funded with existing plan assets.

In addition to the amounts included in the above table, we have contracted with several pipeline companies through 2030 to transport natural gas, ethane and propane production volumes in Appalachia from certain Marcellus Shale wells. The agreements and related fees are contingent on certain pipeline modifications and/or pipeline construction and are commitments that range between three and fifteen year terms which are expected to begin in late 2014 through late 2017. Based on these contracts, we will be obligated for a range of natural gas volumes from 40,000 mcfe per day to 200,000 mcfe per day and ethane and propane volumes from 10,000 to 20,000 bbls per day through the end of the contract terms.

Delivery Commitments

We have various volume delivery commitments that are primarily related to our Midcontinent and Marcellus Shale areas. We may purchase third party volumes to satisfy our commitments or pay demand fees for commitment shortfalls, should they occur. As of December 31, 2013, our delivery commitments through 2028 were as follows:

Year Ending December 31,	Natural Gas (mcf per day)	Ethane (bbls per day)
2014	145,500	15,000
2015	140,538	15,000
2016	102,598	15,000
2017	52,055	15,000
2018 - 2028	—	15,000

Other

We lease acreage that is generally subject to lease expiration if initial wells are not drilled within a specified period, generally between three to five years. We do not expect to lose significant lease acreage because of failure to drill due to inadequate capital, equipment or personnel. However, based on our evaluation of prospective economics, including the cost of infrastructure to connect production, we have allowed acreage to expire and will allow additional acreage to expire in the future. To date, our expenditures to comply with environmental or safety regulations have not been a significant component of our cost structure and are not expected to be significant in the future. However, new regulations, enforcement policies, claims for damages or other events could result in significant future costs.

Hedging – Oil and Gas Prices

We use commodity-based derivative contracts to manage exposures to commodity price fluctuations. We do not enter into these arrangements for speculative or trading purposes. We do not utilize complex derivatives as we typically utilize commodity swaps and collars to (1) reduce the effect of price volatility on the commodities we produce and sell and (2) support our annual capital budget and expenditure plans. In addition, we may utilize basis contracts to hedge the differential between NYMEX and those of our physical pricing points. We do not use derivative instruments for trading purposes. For more discussion of our derivative activities, see "Management's Discussion of Critical Accounting Estimates – Natural Gas and Oil Derivatives" below and "Item 7A. Quantitative and Qualitative Disclosures about Market Risk ─ Commodity Price Risk" and "Other Commodity Risk." For more information regarding the accounting for our derivatives, see the discussion and tables in Notes 2, 11 and 12 to our consolidated financial statements. While there is a risk that the financial benefit of rising natural gas, NGLs and oil prices may not be captured, we believe the benefits of stable and predictable cash flow are more important. Among these benefits are a more efficient utilization of existing personnel and planning for future staff additions, the flexibility to enter into long-term projects requiring substantial committed capital, smoother and more efficient execution of our ongoing development drilling and production enhancement programs, more consistent returns on invested capital, and better access to bank and other credit markets.

Interest Rates

At December 31, 2013, we had $3.1 billion of debt outstanding. Of this amount, $2.7 billion bears interest at fixed rates averaging 5.8%. Bank debt totaling $500.0 million bears interest at floating rates, which averaged 1.8% at year-end 2013. The 30-day LIBO rate on December 31, 2013 was 0.2%. A 1% increase in short-term interest rates on the floating-rate debt outstanding at December 31, 2013 would cost us approximately $5.0 million in additional annual interest expense.

Off-Balance Sheet Arrangements

We do not currently utilize any off-balance sheet arrangements with unconsolidated entities to enhance our liquidity or capital resources position. However, as is customary in the oil and gas industry, we have various contractual work commitments which are described above under cash contractual obligations.

Inflation and Changes in Prices

Our revenues, the value of our assets and our ability to obtain bank loans or additional capital on attractive terms have been and will continue to be affected by changes in natural gas, NGLs and oil prices and the costs to produce our reserves. Natural gas, NGLs and oil prices are subject to significant fluctuations that are beyond our ability to control or predict. Although certain of our costs and expenses are affected by general inflation, inflation does not normally have a significant effect on our business. We expect costs in 2014 to continue to be a function of supply and demand.

Management's Discussion of Critical Accounting Estimates

Our discussion and analysis of our financial condition and results of operations are based upon consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of our financial statements requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at year-end, the reported amounts of revenues and expenses during the year and proved natural gas and oil reserves. Some accounting policies involve judgments and uncertainties to such an extent there is a 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 we believe are reasonable under the circumstances, the results of which form the basis for making judgments about the carrying value of assets and liabilities that are not readily apparent from other sources. Actual results could differ from the estimates and assumptions used.

Certain accounting estimates are considered to be critical if (a) the nature of the estimates and assumptions is material due to the level of subjectivity and judgment necessary to account for highly uncertain matters or the susceptibility of such matters to changes; and (b) the impact of the estimates and assumptions on financial condition or operating performance is material.

Natural Gas and Oil Properties

We use the successful efforts method of accounting for natural gas and oil producing activities as opposed to the alternate acceptable full cost method. We believe that net assets and net income are more conservatively measured under the successful efforts method of accounting than under the full cost method, particularly during periods of active exploration. One difference between the successful efforts method of accounting and the full cost method is under the successful efforts method all exploratory dry holes and geological and geophysical costs are charged against earnings during the periods they occur; whereas, under the full cost method of accounting, such costs are capitalized as assets, pooled with the costs of successful wells and charged against earnings of future periods as a component of depletion expense. Under the successful efforts method of accounting, successful exploration drilling costs and all development costs are capitalized and these costs are systematically charged to expense using the units of production method based on proved developed natural gas and oil reserves as estimated by our engineers and audited by independent engineers. Costs incurred for exploratory wells that find reserves that cannot yet be classified as proved are capitalized on our balance sheet if (a) the well has found a sufficient quantity of reserves to justify its completion as a producing well and (b) we are making sufficient progress assessing the reserves and the economic and operating viability of the project. Proven property leasehold costs are amortized to expense using the units of production method based on total proved reserves. Properties are assessed for impairment as circumstances warrant (at least annually) and impairments to value are charged to expense. The successful efforts method inherently relies upon the estimation of proved reserves, which includes proved developed and proved undeveloped volumes.

Proved reserves are defined by the SEC as those volumes of natural gas, NGLs, condensate and crude oil that geological and engineering data demonstrate with reasonable certainty are recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are volumes expected to be recovered through existing wells with existing equipment and operating methods. Although our engineers are knowledgeable of and follow the guidelines for reserves established by the SEC, including the rule revisions designed to modernize the oil and gas company reserves reporting requirements which we adopted effective December 31, 2009, the estimation of reserves requires engineers to make a significant number of assumptions based on professional judgment. Reserve estimates are updated at least annually and consider recent production levels and other technical information. Estimated reserves are often subject to future revisions, which could be substantial, based on the availability of additional information, including: reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price and cost changes and other economic factors. Changes in natural gas, NGLs and oil prices can lead to a decision to start up or shut in production, which can lead to revisions to reserve quantities. Reserve revisions in turn cause adjustments in our depletion rates. We cannot predict what reserve revisions may be required in future periods. Reserve estimates are reviewed and approved by our Senior Vice President of Reservoir Engineering and Economics who reports directly to our President and Chief Executive Officer. For additional discussion, see "Proved Reserves," in Item 1 and 2 of this report. To further ensure the reliability of our reserve estimates, we engage independent petroleum consultants to audit our estimates of proved reserves. Estimates prepared by third parties may be higher or lower than those included herein. Independent petroleum consultants audited approximately 96% of our reserves in 2013 compared to 93% in 2012 and 89% in 2011. Historical variances between our reserve estimates and the aggregate estimates of our consultants have been less than 5%. The reserves included in this report are those reserves estimated by our petroleum engineering staff.

Depletion rates are determined based on reserve quantity estimates and the capitalized costs of producing properties. As the estimated reserves are adjusted, the depletion expense for a property will change, assuming no change in production volumes or the capitalized costs. While total depletion expense for the life of a property is limited to the property's total cost, proved reserve revisions result in a change in the timing of when depletion expense is recognized. Downward revisions of proved reserves may result in an acceleration of depletion expense, while upward revisions tend to lower the rate of depletion expense recognition. Based on proved reserves at December 31, 2013, we estimate that a 1% change in proved reserves would increase or decrease 2014 depletion expense by approximately $5.3 million (based on current production estimates). Estimated reserves are used as the basis for calculating the expected future cash flows from property asset groups, which are used to determine whether that property may be impaired. Reserves are also used to estimate the supplemental disclosure of the standardized measure of discounted future net cash flows relating to natural gas and oil producing activities and reserve quantities in Note 19 to our consolidated financial statements. Changes in the estimated reserves are considered a change in estimate for accounting purposes and are reflected on a prospective basis. It should not be assumed that the standardized measure is the current market value of our estimated proved reserves.

We monitor our long-lived assets recorded in natural gas and oil properties in our consolidated balance sheets to ensure they are fairly presented. We must evaluate our properties for potential impairment when circumstances indicate that the carrying value of an asset could exceed its fair value. A significant amount of judgment is involved in performing these evaluations since the results are based on estimated future events. Such events include a projection of future natural gas, NGLs and oil prices, an estimate of the ultimate amount of recoverable natural gas, NGLs and oil reserves that will be produced from the property asset groups future production, future production costs, future abandonment costs, and future inflation. The need to test a property asset group for impairment can be based on several factors, including a significant reduction in sales prices for natural gas, NGLs and/or oil, unfavorable adjustments to reserves, physical damage to production equipment and facilities, a change in costs, or other changes to contracts or environmental regulations. Our natural gas and oil properties are reviewed for potential impairments at the lowest levels for which there are identifiable cash flows that are largely independent of other groups of assets which is the level at which depletion is calculated. The review is done by determining if the historical cost of proved properties less the applicable accumulated depreciation, depletion and amortization is less than the estimated undiscounted future net cash flows. We estimate prices based upon market related information including published futures prices. The estimated future level of production, which is based on proved and risk adjusted probable and possible reserves, has assumptions surrounding the future levels of prices and costs, field decline rates, market demand and supply and the economic and regulatory climates. In certain circumstances, we also consider potential sales of properties to third parties in our estimates of future cash flows. When the carrying value exceeds the sum of future net cash flows, an impairment loss is recognized for the difference between the estimated fair market value (as determined by discounted future net cash flows using a discount rate similar to that used by market participants) and the carrying value of the asset. We cannot predict whether impairment charges may be required in the future.

Our historical impairment of producing properties has been $7.0 million in 2013, $34.3 million in 2012 and $38.7 million in 2011. In 2013, an impairment of $7.0 million was recorded on certain South Texas properties due to lower reserves and we also recorded a $741,000 impairment of remaining surface acreage in North Texas. In 2012, an impairment was recorded on our Mississippi properties of $31.1 million due to lower reserves and lower natural gas prices, an impairment of $3.2 million was recorded on our remaining North Texas Barnett assets (due to lower natural gas prices and including the possibility of sale) and we also recorded a $1.3 million impairment of remaining surface acreage in the Barnett. In 2011, an impairment was recorded on our East Texas properties of $31.2 million due to lower reserves, lower natural gas prices and including the possibility of a sale and a $7.5 million impairment was also recorded related to our Gulf Coast onshore properties due to lower reserves and lower natural gas prices. We believe that a sensitivity analysis regarding the effect of changes in assumptions on estimated impairment is impractical to provide because of the number of assumptions and variables involved which have interdependent effects on the potential outcome. If natural gas, NGLs and oil prices decrease or drilling efforts are unsuccessful, we may be required to record additional impairments.

We evaluate our unproved property investment periodically for impairment. The majority of these costs generally relate to the acquisition of leaseholds. The costs are capitalized and evaluated (at least quarterly) as to recoverability, based on changes brought about by economic factors and potential shifts in business strategy employed by management. Impairment of a significant portion of our unproved properties is assessed and amortized on an aggregate basis based on our average holding period, expected forfeiture rate and anticipated drilling success. Potential impairment of individually significant unproved property is assessed on a property-by-property basis considering a combination of time, geologic and engineering factors. Unproved properties had a net book value of $807.0 million at December 31, 2013 compared to $743.5 million at December 31, 2012. We have recorded abandonment and impairment expense related to unproved properties of $51.9 million in 2013 compared to $125.3 million in 2012 and $79.7 million in 2011.

Natural Gas and Oil Derivatives

All derivative instruments are recorded on our consolidated balance sheets as either an asset or a liability measured at its fair value. Changes in a derivative's fair value are recognized in earnings unless specific hedge accounting criteria are met. All of our derivative instruments are issued to manage the price risk attributable to our expected natural gas, NGLs and oil production. In determining the amounts to be recorded for our open hedge contracts, we are required to estimate the fair value of the derivative. Except for four basis swap contracts that have a fair value of $548,000 at December 31, 2013, our derivatives are measured using a market approach using third-party pricing services which have been corroborated with data from active markets or broker quotes. Our third party pricing service uses observable market prices and we do not adjust the valuations. While we remain at risk for possible changes in the market value of commodity derivatives, such risk should be mitigated by price changes in the underlying physical commodity. The determination of fair values includes various factors including the impact of our nonperformance risk on our liabilities and the credit standing of our counterparties.

As of December 31, 2013, our counterparties include thirteen financial institutions, of which all but two are secured lenders in our bank credit facility. For those counterparties that are not secured lenders in our bank credit facility or those for which we do not have set-off rights, net derivative asset values are determined in part, by reviewing credit default swap spreads for the counterparties. Net derivative liabilities are determined, in part, by using our market credit spread.

Through February 28, 2013, we elected to designate our commodity derivative instruments that qualified for hedge accounting as cash flow hedges. To designate a derivative as a cash flow hedge, we documented at the hedge's inception our assessment that the derivative would be highly effective in offsetting expected changes in cash flows from the item hedged. This assessment, which was updated at least quarterly, was based on the most recent relevant historical correlation between the derivative and the item hedged. The ineffective portion of the hedge was calculated as the difference between the change in fair value of the derivative and the estimated change in cash flows from the item hedged. If, during the derivative's term, we determined the hedge was no longer highly effective, hedge accounting was prospectively discontinued and any remaining unrealized gains or losses, based on the effective portion of the derivative at that date, was reclassified to earnings as natural gas, NGLs and oil sales when the underlying transaction occurred. If it was determined that the designated hedged transaction was not probable to occur, any unrealized gains or losses were recognized immediately in derivative fair value income or loss in the accompanying statements of operations. In 2012 and 2011, we did not transfer any gains or losses into derivative fair value income or loss as a result of discontinuing hedge accounting. In 2013, we recognized a pre-tax gain of $3.9 million in derivative fair value as a result of the discontinuance of hedge accounting where we determined the transaction was probable not to occur primarily due to the sale of our Delaware and Permian Basin properties in Southeast New Mexico and West Texas.

Effective March 1, 2013, we elected to de-designate all commodity contracts that were previously designated as cash flow hedges and elected to discontinue hedge accounting prospectively. Accumulated Other Comprehensive Income ("AOCI") included $103.6 million ($63.2 million after tax) of unrealized net gains, representing the marked-to-market value of the effective portion of our cash flow hedges as of February 28, 2013. As a result of discontinuing hedge accounting, the marked-to-market values included in AOCI as of the de-designation date were frozen and will be reclassified into earnings in natural gas, NGLs and oil sales in future periods as the underlying hedged transactions occur. As of December 31, 2013, an unrealized derivative gain of $10.2 million was recorded in AOCI which we expect to reclassify to earnings in 2014.

With the election to de-designate hedging instruments, all of our derivative instruments continue to be recorded at fair value with unrealized gains and losses recognized immediately in earnings rather than as AOCI. These marked-to-market adjustments will produce a degree of earnings volatility that can be significant from period to period, but such adjustments will have no cash flow impact relative to changes in market prices. The impact to cash flow occurs upon settlement of the underlying contract. Cash flows from our derivative contract settlements are reflected in cash flows provided from operating activities in the accompanying consolidated statements of cash flows.

At times, we have also entered into basis swap agreements which do not qualify for hedge accounting and are marked to market. The price we receive for our natural gas production can be more or less than the NYMEX price because of adjustments for delivery location ("basis"), relative quality and other factors; therefore, at times we have entered into basis swap agreements that effectively lock in our basis adjustments.

Asset Retirement Obligations

We have significant obligations to remove tangible equipment and restore land at the end of natural gas and oil production operations. Removal and restoration obligations are primarily associated with plugging and abandoning wells. Estimating the future asset removal costs is difficult and requires us to make estimates and judgments because most of the removal obligations are many years in the future and contracts and regulations often have vague descriptions of what constitutes removal. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations.

Inherent in the fair value calculation are numerous assumptions and judgments including the ultimate retirement costs, inflation factors, credit-adjusted discount rates, timing of retirement, and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the present value of the existing asset retirement obligation ("ARO"), a corresponding adjustment is made to the natural gas and oil property balance. For example, as we analyze actual plugging and abandonment information, we may revise our estimate of current costs, the assumed annual inflation of the costs and/or the assumed productive lives of our wells. During 2013, we increased our existing ARO by $67.6 million or approximately 46% of the ARO at December 31, 2012. This increase was due to an increase in the estimated costs to plug and abandon our wells. During 2012, we increased our existing estimated ARO by $48.2 million or approximately 57% of the asset retirement obligation at December 31, 2010 due to an increase in estimated costs to plug and abandon our wells and a decrease in the production life of certain of our natural gas properties due to declining prices. In addition, increases in the discounted ARO resulting from the passage of time are reflected as accretion expense, a component of depletion, depreciation and amortization in the accompanying consolidated statements of operations. Because of the subjectivity of assumptions and the relatively long lives of most of our wells, the costs to ultimately retire our wells may vary significantly from prior estimates.

Deferred Taxes

We are subject to income and other taxes in all areas in which we operate. When recording income tax expense, certain estimates are required because income tax returns are generally filed many months after the close of a calendar year, tax returns are subject to audit, which can take years to complete, and future events often impact the timing of when income tax expenses and benefits are recognized. We have deferred tax assets relating to tax operating loss carryforwards and other deductible differences. We routinely evaluate deferred tax assets to determine the likelihood of realization and, in certain jurisdictions, we must estimate our expected future taxable income to complete this assessment. Numerous assumptions are inherent in the estimation of future taxable income, including assumptions about the timing and realization of deferred tax items, future operating conditions (particularly related to prevailing natural gas, NGLs and oil prices) and the overall financial condition of the markets we operate in. The estimates or assumptions used in determining future taxable income are consistent with those used in our internal budgets and forecasts. A valuation allowance is recognized on deferred tax assets when we believe that certain of these assets are more likely than not to be realized. We do not currently have a valuation allowance on our federal net operating loss carryforwards. During 2013, we increased our valuation allowance we had against our state net operating loss carryforwards from $2.0 million to $3.0 million.

In determining deferred tax liabilities, accounting rules require AOCI to be considered, even though such income or loss has not yet been earned. At year-end 2013, deferred tax liabilities exceeded deferred tax assets by $720.6 million with $4.0 million of deferred tax liability related to net deferred hedging gains in AOCI. At year-end 2012, deferred tax liabilities exceeded deferred tax assets by $736.2 million with $53.6 million of deferred tax liability related to net deferred hedging gains in AOCI.

We may be challenged by taxing authorities over the amount and/or timing of recognition of revenues and deductions in our various income tax returns. Although we believe that we have adequately provided for all taxes, gains or losses could occur in the future due to changes in estimates or resolution of outstanding tax matters.

Contingent Liabilities

A provision for legal, environmental and other contingent matters is charged to expense when the loss is probable and the cost or range of cost can be reasonably estimated. Judgment is often required to determine when expenses should be recorded for legal, environmental and contingent matters. In addition, we often must estimate the amount of such losses. In many cases, our judgment is based on the input of our legal advisors and on the interpretation of laws and regulations, which can be interpreted differently by regulators and/or the courts. Actual costs can differ from estimates for many reasons. We monitor known and potential legal, environmental and other contingent matters and make our best estimate of when to record losses for these matters based on available information. Although we continue to monitor all contingencies closely, particularly our outstanding litigation, we currently have no material accruals for contingent liabilities.

Revenue Recognition

Natural gas, NGLs and oil sales are recognized when we deliver our production to the customer and collectability is reasonably assured. We use the sales method to account for gas imbalances, recognizing revenue based on gas delivered rather than our working interest share of gas produced. We generally sell natural gas, NGLs and oil under two types of agreements, which are common in our industry. Both types of agreements include transportation charges. We report our gathering and transportation costs in accordance with FASB 605-45-05 of Subtopic 605-45 for Revenue Recognition. One type of agreement is a netback arrangement, under which we sell natural gas and oil at the wellhead and collect a price, net of transportation incurred by the purchaser. In this case, we record revenue at the net price we received from the purchaser. In the case of NGLs, we receive a net price from the purchaser (which is net of processing costs) which is recorded in revenue at the net price. Under the other arrangement, we sell natural gas or oil at a specific delivery point, pay transportation, gathering and compression to a third party and receive proceeds from the purchaser with no deduction. In that case, we record revenue at the price received from the purchaser and record these third party costs as transportation, gathering and compression expense.

Stock-based Compensation Arrangements

The fair value of stock options and stock-settled SARs is estimated on the date of grant using the Black-Scholes-Merton option-pricing model. The model employs various assumptions, based on management's best estimates at the time of the grant, which impact the fair value calculated and ultimately, the expense that is recognized over the life of the award. We have utilized historical data and analyzed current information to reasonably support these assumptions. The fair value of restricted stock awards is determined based on the fair market value of our common stock on the date of grant.

We recognize stock-based compensation expense on a straight-line basis over the requisite service period for the entire award. The expense we recognize is net of estimated forfeitures. We estimate our forfeiture rate based on prior experience and adjust it as circumstances warrant. See Note 13 to our consolidated financial statements for more information.

Accounting Standards Not Yet Adopted

In February 2013, an accounting standards update was issued to provide guidance for the recognition, measurement, and disclosure of obligations resulting from joint and several liability arrangements for which the total amount of the obligation is fixed at the reporting date, except for obligations such as asset retirement and environmental obligations, contingencies, guarantees, income taxes and retirement benefits, which are separately addressed within United States generally accepted accounting principles ("U.S. GAAP"). An entity is required to measure obligations resulting from joint and several liability arrangements for which the total amount of the obligation is fixed at the reporting date as the sum of 1) the amount the entity agreed to pay on the basis of its arrangement among its co-obligors and 2) any amount the entity expects to pay on behalf of its co-obligors. Disclosure of the nature of the obligation, including how the liability arose, the relationship with other co-obligors and the terms and conditions of the arrangement is required. In addition, the total outstanding amount under the arrangement, not reduced by the effect of any amounts that may be recoverable from other entities, plus the carrying amount of any liability or receivable recognized must be disclosed. This accounting standards update is effective for us beginning the first quarter 2014 and should be applied retrospectively for those in-scope obligations resulting from joint and several liability arrangements that exist at the beginning of 2014. Early adoption is permitted. We do not expect this accounting standards update to have a significant impact on our consolidated results of operations, financial position or cash flows.

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 natural gas, NGLs and oil 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 exposure. All of our market-risk sensitive instruments were entered into for purposes other than trading. All accounts are US dollar denominated.

Market Risk

We are exposed to market risks related to the volatility of natural gas, NGLs and oil prices. We employ various strategies, including the use of commodity derivative instruments, to manage the risks related to these price fluctuations. These derivative instruments apply to a varying portion of our production and provide only partial price protection. These arrangements limit the benefit to us of increases in prices but offer protection in the event of price declines. Further, if our counterparties defaulted, this protection might be limited as we might not receive the benefits of the derivatives. Realized prices are primarily driven by worldwide prices for oil and spot market prices for North American natural gas production. Natural gas and oil prices have been volatile and unpredictable for many years. Natural gas prices affect us more than oil prices because approximately 69% of our December 31, 2013 proved reserves are natural gas. We are also exposed to market risks related to changes in interest rates. These risks did not change materially from December 31, 2012 to December 31, 2013.

Commodity Price Risk

We use commodity-based derivative contracts to manage exposures to commodity price fluctuations. We do not enter into these arrangements for speculative or trading purposes. We do not utilize complex derivatives such as swaptions, knockouts or extendable swaps. At times, certain of our derivatives are swaps where we receive a fixed price for our production and pay market prices to the counterparty. Our derivatives program also includes collars, which establishes a minimum floor price and a predetermined ceiling price. At December 31, 2013, our derivatives program includes swaps and collars. These contracts expire monthly through December

2016. Their fair value, represented by the estimated amount that would be realized upon immediate liquidation as of December 31, 2013, approximated a net unrealized pre-tax loss of $16.5 million compared to a pre-tax gain of $144.3 million at December 31, 2012. This change is primarily related to the settlements of derivative contracts during 2013 and to the natural gas, NGLs and oil futures prices as of December 31, 2013, in relation to the new commodity derivative contracts we entered into during 2013 for 2014, 2015 and 2016. At December 31, 2013, the following commodity derivative contracts were outstanding:

Period	Contract Type	Volume Hedged	Weighted Average Hedge Price	Fair Market Value
				(in thousands)
Natural Gas				
2014	Collars	447,500 Mmbtu/day	$ 3.84–$ 4.48	$ (3,120)
2015	Collars	145,000 Mmbtu/day	$ 4.07–$ 4.56	$ 5,831
2014	Swaps	219,397 Mmbtu/day	$ 4.17	$ (1,705)
2015	Swaps	154,966 Mmbtu/day	$ 4.16	$ 923
2016	Swaps	20,000 Mmbtu/day	$ 4.16	$ 233
Crude Oil				
2014	Collars	2,000 bbls/day	$ 85.55–$ 100.00	$ (398)
2014	Swaps	9,004 bbls/day	$ 94.43	$ (3,365)
2015	Swaps	4,000 bbls/day	$ 89.60	$ 2,222
NGLs (C3 - Propane)				
2014	Swaps	11,000 bbls/day	$ 1.01/gallon	$ (17,346)
NGLs (NC4 - Normal butane)				
2014	Swaps	3,000 bbls/day	$ 1.33/gallon	$ 106
NGLs (C5 - Natural Gasoline)				
2014	Swaps	1,000 bbls/day	$ 2.11/gallon	$ 121

We expect our NGLs production to continue to increase. In our Marcellus Shale operations, propane is a large product component of our NGLs production and we believe NGLs prices are somewhat seasonal. Therefore, the percentage of NGLs prices to NYMEX WTI (or West Texas Intermediate) will vary due to product components, seasonality and geographic supply and demand. We sell NGLs in several regional markets.

Currently, there is little demand, or facilities to supply the existing demand, elsewhere, for ethane in the Appalachian region. We have previously announced three ethane agreements wherein we have contracted to either sell or transport ethane from our Marcellus Shale area, two of which began operations in late 2013. The remaining facility is expected to begin operations in mid-2015. We cannot assure you that these facilities will become or remain available. If we are not able to sell ethane, we may be required to curtail production which will adversely affect our revenues.

Other Commodity Risk

We are impacted by basis risk, caused by factors that affect the relationship between commodity futures prices reflected in derivative commodity instruments and the cash market price of the underlying commodity. Natural gas transaction prices are frequently based on industry reference prices that may vary from prices experienced in local markets. If commodity price changes in one region are not reflected in other regions, derivative commodity instruments may no longer provide the expected hedge, resulting in increased basis risk. In addition to the collars and swaps above, we have entered into basis swap agreements. The price we receive for our gas production can be more or less than the NYMEX price because of adjustments for delivery location (“basis”), relative quality and other factors; therefore, we have entered into basis swap agreements that effectively lock in the basis adjustments. The fair value of the basis swaps was a gain of $3.9 million at December 31, 2013, the volumes are for 320,280 Mmbtu/day and they expire monthly through October 2014.

The following table shows the fair value of our collars, swaps and basis swaps and the hypothetical change in fair value that would result from a 10% and a 25% change in commodity prices at December 31, 2013. We remain at risk for possible changes in the market value of commodity derivative instruments; however, such risks should be mitigated by price changes in the underlying physical commodity (in thousands):

		Hypothetical Change in Fair Value		Hypothetical Change in Fair Value	
		Increase in Commodity Price of		Decrease in Commodity Price of	
	Fair Value	10%	25%	10%	25%
Collars	$ 2,314	$ (69,292)	$ (188,807)	$ 64,824	$ 181,224
Swaps	(18,812)	(128,008)	(319,976)	129,863	325,146
Basis swaps	3,929	2,503	6,318	(2,561)	(6,441)

Our commodity-based contracts expose us to the credit risk of non-performance by the counterparty to the contracts. Our exposure is diversified among major investment grade financial institutions and we have master netting agreements with the majority of our counterparties that provide for offsetting payables against receivables from separate derivative contracts. Our derivative contracts are with multiple counterparties to minimize our exposure to any individual counterparty. At December 31, 2013, our derivative counterparties include thirteen financial institutions, of which all but two are secured lenders in our bank credit facility. Counterparty credit risk is considered when determining the fair value of our derivative contracts. While counterparties are major investment grade financial institutions, the fair value of our derivative contracts have been adjusted to account for the risk of non-performance by certain of our counterparties, which was immaterial.

Interest Rate Risk

We are exposed to interest rate risk on our bank debt. We attempt to balance variable rate debt, fixed rate debt and debt maturities to manage interest costs, interest rate volatility and financing risk. This is accomplished through a mix of fixed rate senior subordinated debt and variable rate bank debt. At December 31, 2013, we had $3.1 billion of debt outstanding. Of this amount, $2.7 billion bears interest at a fixed rate averaging 5.8%. Bank debt totaling $500.0 million bears interest at floating rates, which was 1.8% on that date. On December 31, 2013, the 30-day LIBO rate was 0.2%. A 1% increase in short-term interest rates on the floating-rate debt outstanding at December 31, 2013 would cost us approximately $5.0 million in additional annual interest expense.

The fair value of our subordinated debt is based on year-end quoted market prices. The following table presents information on these fair values (in thousands):

	Carrying Value	Fair Value
Fixed rate debt:		
Senior Subordinated Notes due 2019 (The interest rate is fixed at a rate of 8.0%)	$ 290,516	$ 319,500
Senior Subordinated Notes due 2020 (The interest rate is fixed at a rate of 6.75%)	500,000	541,250
Senior Subordinated Notes due 2021 (The interest rate is fixed at a rate of 5.75%)	500,000	530,625
Senior Subordinated Notes due 2022 (The interest rate is fixed at a rate of 5.00%)	600,000	588,750
Senior Subordinated Notes due 2023 (The interest rate is fixed at a rate of 5.00%)	750,000	732,188
	$ 2,640,516	$ 2,712,313

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

For financial statements required by Item 8, see Item 15 in Part IV of this report.

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 required by Rule 13a-15(b) under the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this Form 10-K. Our disclosure controls and procedures are designed to provide reasonable assurance that information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon the evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective as of December 31, 2013 at the reasonable assurance level.

Changes in Internal Controls over Financial Reporting. There have been no changes in our system of internal control over financial reporting (such as term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the quarter ended December 31, 2013 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Annual Report on Internal Control over Financial Reporting. See "Management's Report on Internal Control over Financial Reporting" and "Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting" which appear on pages F-2 and F-3, respectively, under "Item 15. Exhibits, Financial Statements Schedules."

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The officers and directors are listed below with a description of their experience and certain other information. Each director was elected for a one-year term at the 2013 annual stockholders' meeting. Officers are appointed by our board of directors.

	Age	Officer Since	Position
Anthony V. Dub	64	1995	Director
V. Richard Eales	77	2001	Lead Independent Director
Allen Finkelson	67	1994	Director
James M. Funk	64	2008	Director
Jonathan S. Linker	65	2002	Director
Mary Ralph Lowe	67	2013	Director
Kevin S. McCarthy	54	2005	Director
John H. Pinkerton	59	1990	Director, Non-Executive Chairman
Jeffrey L. Ventura	56	2003	Director, President and Chief Executive Officer
Roger S. Manny	56	2003	Executive Vice President – Chief Financial Officer
Ray N. Walker, Jr.	56	2010	Executive Vice President – Chief Operating Officer
John K. Applegath	65	2014	Senior Vice President – Southern Marcellus Shale
Alan W. Farquharson	56	2007	Senior Vice President – Reservoir Engineering & Economics
Dori A. Ginn	56	2009	Senior Vice President – Controller and Principal Accounting Officer
David P. Poole	51	2008	Senior Vice President – General Counsel and Corporate Secretary
Chad L. Stephens	58	1990	Senior Vice President – Corporate Development
Rodney L. Waller	64	1999	Senior Vice President

Anthony V. Dub became a director in 1995. Mr. Dub is Chairman of Indigo Capital, LLC, a financial advisory firm based in New York. Before forming Indigo Capital in 1997, he served as an officer of Credit Suisse First Boston ("CSFB"). Mr. Dub joined CSFB in 1971 and was named a Managing Director in 1981. Mr. Dub led a number of departments during his 26 year career at CSFB including the Investment Banking Department. After leaving CSFB, Mr. Dub became Vice Chairman and a director of Capital IQ, Inc. until its sale to Standard & Poor's in 2004. Capital IQ is a leader in helping organizations capitalize on synergistic integration of market intelligence, institutional knowledge and relationships. Mr. Dub received a Bachelor of Arts degree, magna cum laude, from Princeton University.

V. Richard Eales became a director in 2001 and was elected as Lead Independent Director in 2008. Mr. Eales has over 35 years of experience in the energy, technology and financial industries. He is currently retired, having been a financial consultant serving energy and information technology businesses from 1999 through 2002. Mr. Eales was employed by Union Pacific Resources Group Inc. from 1991 to 1999 serving as Executive Vice President from 1995 through 1999. Before 1991, Mr. Eales served in various financial capacities with Butcher & Singer and Janney Montgomery Scott, investment banking firms, as CFO of Novell, Inc., a technology company, and in the treasury department of Mobil Oil Corporation. Mr. Eales received his Bachelor of Chemical Engineering degree from Cornell University and his Master's degree in Business Administration from Stanford University.

Allen Finkelson became a director in 1994. Mr. Finkelson was a partner at Cravath, Swaine & Moore LLP from 1977 to 2011, with the exception of the period 1983 through 1985, when he was a managing director of Lehman Brothers Kuhn Loeb Incorporated. Mr. Finkelson joined Cravath, Swaine & Moore LLP in 1971. Mr. Finkelson earned a Bachelor of Arts from St. Lawrence University and a J.D. from Columbia University School of Law.

James M. Funk became a director in December 2008. Mr. Funk is an independent consultant and producer with over 30 years of experience in the energy industry. Mr. Funk served as Sr. Vice President of Equitable Resources and President of Equitable Production Co. from June 2000 until December 2003 and has been an independent consultant and oil and gas producer since that time. Previously, Mr. Funk was employed by Shell Oil Company for 23 years in senior management and technical positions. Mr. Funk has previously served on the boards of Westport Resources (2000 to 2004) and Matador Resources Company (2003 to 2008). Mr. Funk currently serves as a Director of Superior Energy Services, Inc., a public oil field services company headquartered in New Orleans, Louisiana and Sonde Resources Corp., a public company headquartered in Calgary, Alberta. Mr. Funk received a B.A. degree in Geology from Wittenberg University, a M.S. in Geology from the University of Connecticut, and a PhD in Geology from the University of Kansas. Mr. Funk is a Certified Petroleum Geologist.

Jonathan S. Linker became a director in 2002. Mr. Linker previously served as a director of Range from 1998 to 2000. He has been active in the energy industry for over 37 years. Mr. Linker joined First Reserve Corporation in 1988 and was a Managing

Director of the firm from 1996 through 2001. Mr. Linker is currently Manager of Houston Energy Advisors LLC, an investment advisor providing management and investment services to two private equity funds. Mr. Linker has been President and a director of IDC Energy Corporation since 1987, a director and officer of Sunset Production Corporation since 1991 serving currently as Chairman. Mr. Linker is also on the board of Flex Energy, Inc., and a Manager of Crescent Energy Services and Stonegate Production Company, LLC. Mr. Linker received a Bachelor of Arts in Geology from Amherst College, a Masters in Geology from Harvard University and an MBA from Harvard Graduate School of Business Administration.

Mary Ralph Lowe became a director in 2013. Ms. Lowe has been president and chief executive officer of Maralo, LLC, (formerly Maralo, Inc.), an independent oil and gas exploration and production company, and ranching operation, since 1973, and a member of its board of directors since 1975. Ms. Lowe was appointed by the Company as a director effective April 1, 2013. Ms. Lowe also serves on the Board of Trustees of Texas Christian University, the Board of the Performing Arts Center of Fort Worth, the Board of the National Cowgirl Museum and Hall of Fame, and the Board of The Modern Art Museum of Fort Worth. Ms. Lowe previously served on the Board of Apache Corporation, a large oil and gas exploration company.

Kevin S. McCarthy became a director in 2005. Mr. McCarthy is Chairman, Chief Executive Officer and President of Kayne Anderson MLP Investment Company, Kayne Anderson Energy Total Return Fund, Inc., Kayne Anderson Midstream/Energy Fund, Inc. and Kayne Anderson Energy Development Company, which are each NYSE listed closed-end investment companies. Mr. McCarthy joined Kayne Anderson Capital Advisors as a Senior Managing Director in 2004 from UBS Securities LLC where he was global head of energy investment banking. In this role, he had senior responsibility for all of UBS' energy investment banking activities, including direct responsibilities for securities underwriting and mergers and acquisitions in the energy industry. From 1995 to 2000, Mr. McCarthy led the energy investment banking activities of Dean Witter Reynolds and then PaineWebber Incorporated. He began his investment banking career in 1984. He is also on the board of directors of Emerge Energy Services, L.P. He earned a Bachelor of Arts in Economics and Geology from Amherst College and an MBA in Finance from the University of Pennsylvania's Wharton School.

John H. Pinkerton, Non-Executive Chairman and a director, became a director in 1988 and was elected Chairman of the Board of Directors in 2008. He joined Range as President in 1990 and was appointed Chief Executive Officer in 1992. Previously, Mr. Pinkerton was employed by Snyder Oil Corporation, serving in numerous capacities, the last of which was Senior Vice President. Mr. Pinkerton currently serves on the Board of Trustees of Texas Christian University and is a member of the Executive Committee of America's Natural Gas Alliance (ANGA). Mr. Pinkerton received his Bachelor of Arts in Business Administration from Texas Christian University and a Master's degree from the University of Texas at Arlington.

Jeffrey L. Ventura, President and Chief Executive Officer and a director, joined Range in 2003 as Chief Operating Officer and became a director in 2005. Mr. Ventura was named Chief Executive Officer effective January 1, 2012. Previously, Mr. Ventura served as President and Chief Operating Officer of Matador Petroleum Corporation which he joined in 1997. Prior to his service at Matador, Mr. Ventura spent eight years at Maxus Energy Corporation where he managed various engineering, exploration and development operations and was responsible for coordination of engineering technology. Previously, Mr. Ventura was with Tenneco Oil Exploration and Production, where he held various engineering and operating positions. Mr. Ventura holds a Bachelor of Science degree in Petroleum and Natural Gas Engineering from the Pennsylvania State University.

Roger S. Manny, Executive Vice President – Chief Financial Officer. Mr. Manny joined Range in 2003. Previously, Mr. Manny served as Executive Vice President and Chief Financial Officer of Matador Petroleum Corporation from 1998 until joining Range. Before 1998, Mr. Manny spent 18 years at Bank of America and its predecessors where he served as Senior Vice President in the energy group. Mr. Manny holds a Bachelor of Business Administration degree from the University of Houston and a Masters of Business Administration from Houston Baptist University.

Ray N. Walker, Jr., Executive Vice President – Chief Operating Officer, joined Range in 2006 and was elected to his current position in January 2014. Previously, Mr. Walker served as Senior Vice President – Chief Operating Officer, Senior Vice President-Environment, Safety and Regulatory and Senior Vice President-Marcellus Shale where he led the development of the Company's Marcellus Shale division. Mr. Walker is a Petroleum Engineer with more than 35 years of oil and gas operations and management experience having previously been employed by Halliburton in various technical and management roles, Union Pacific Resources and several private companies in which Mr. Walker served as an officer. Mr. Walker has a Bachelor of Science degree, in Agricultural Engineering from Texas A&M University.

John K. Applegath, Senior Vice President – Southern Marcellus Shale, joined Range in 2008 and was elected to his current position in January 2014. Mr. Applegath previously served as Vice President – Southern Marcellus Shale Division. Mr. Applegath has over 38 years of industry experience with Exxon, Champlin Petroleum, Union Pacific Resources, and has served as President and Chief Operating Officer of Basic Resources and Division Operations Manager with Anadarko Petroleum. Mr. Applegath served our country in the United States Army as a Chief Warrant Officer II while a helicopter pilot in Vietnam. Mr. Applegath earned a Bachelor of Science degree in Chemical Engineering from the University of Houston.

Alan W. Farquharson, Senior Vice President – Reservoir Engineering & Economics, joined Range in 1998. Mr. Farquharson has held the positions of Manager and Vice President of Reservoir Engineering before being promoted to Senior Vice President – Reservoir Engineering in February 2007 and his current position in January 2012 with his assumption of additional responsibilities for strategic allocation of capital. Previously, Mr. Farquharson held positions with Union Pacific Resources including Engineering Manager Business Development – International. Before that, Mr. Farquharson held various technical and managerial positions at Amoco and Hunt Oil. He holds a Bachelor of Science degree in Electrical Engineering from the Pennsylvania State University.

Dori A. Ginn, Senior Vice President – Controller and Principal Accounting Officer, joined Range in 2001 and was previously Vice President, Controller and Principal Accounting Officer. Ms. Ginn has held the positions of Financial Reporting Manager, Vice President and Controller before being elected to Principal Accounting Officer in September 2009. Prior to joining Range, she held various accounting positions with Doskocil Manufacturing Company and Texas Oil and Gas Corporation. Ms. Ginn received a Bachelor of Business Administration in Accounting from the University of Texas at Arlington. She is a certified public accountant.

David P. Poole, Senior Vice President – General Counsel and Corporate Secretary, joined Range in June 2008. Mr. Poole has over 23 years of legal experience. From May 2004 until March 2008 he was with TXU Corp., serving last as Executive Vice President – Legal, and General Counsel. Prior to joining TXU, Mr. Poole spent 16 years with Hunton & Williams LLP and its predecessor, where he was a partner and last served as the Managing Partner of the Dallas office. Mr. Poole graduated from Texas Tech University with a B.S. in Petroleum Engineering and received a J.D. magna cum laude from Texas Tech University School of Law.

Chad L. Stephens, Senior Vice President – Corporate Development, joined Range in 1990. Before 2002, Mr. Stephens held the position of Senior Vice President – Southwest. Previously, Mr. Stephens was with Duer Wagner & Co., an independent oil and gas producer for approximately two years. Before that, Mr. Stephens was an independent oil operator in Midland, Texas for four years. From 1979 to 1984, Mr. Stephens was with Cities Service Company and HNG Oil Company. Mr. Stephens holds a Bachelor of Arts degree in Finance and Land Management from the University of Texas.

Rodney L. Waller, Senior Vice President joined Range in 1999. Mr. Waller served as Corporate Secretary from 1999 until 2008. Previously, Mr. Waller was Senior Vice President of Snyder Oil Corporation. Before joining Snyder, Mr. Waller was with Arthur Andersen. Mr. Waller is a certified public accountant and petroleum land man. Mr. Waller received a summa cum laude Bachelor of Arts degree in Accounting from Harding University.

Section 16(a) Beneficial Ownership Reporting Compliance

See the material appearing under the heading "Section 16(a) Beneficial Ownership Reporting Compliance" in the Range Proxy Statement for the 2013 Annual Meeting of Stockholders which is incorporated herein by reference. Section 16(a) of the Exchange Act requires our directors, officers (including a person performing a principal policy-making function) and persons who own more than 10% of a registered class of our equity securities to file with the Commission initial reports of ownership and reports of changes in ownership of our common stock and other equity securities. Directors, officers and 10% holders are required by Commission regulations to send us copies of all of the Section 16(a) reports they file. Based solely on a review of the copies of the forms sent to us and the representations made by the reporting persons to us, we believe that, during the fiscal year ended December 31, 2013, our directors, officers and 10% holders complied with all filing requirements under Section 16(a) of the Exchange Act.

Code of Ethics

Code of Ethics. We have adopted a Code of Ethics that applies to our principal executive officer, principal financial officer, principal accounting officer, or persons performing similar functions (as well as directors and all other employees). A copy is available on our website, www.rangeresources.com and a copy in print will be provided to any person without charge, upon request. Such requests should be directed to the Corporate Secretary, 100 Throckmorton Street, Suite 1200, Fort Worth, Texas 76102 or by calling (817) 870-2601. We intend to disclose any amendments to or waivers of the Code of Ethics on behalf of our President and Chief Executive Officer, Chief Financial Officer, Controller and persons performing similar functions on our website, under the Corporate Governance caption, promptly following the date of such amendment or waiver.

Identifying and Evaluating Nominees for Directors

See "Identifying and Evaluating Nominees for Directors, including Diversity Considerations" in the Range Proxy Statement for the 2014 Annual Meeting of stockholders, which is incorporated herein by reference.

Audit Committee

See the material under the heading "Audit Committee" in the Range Proxy Statement for the 2014 Annual Meeting of Stockholders, which is incorporated herein by reference.

NYSE 303A Certification

The President and Chief Executive Officer of Range Resources Corporation made an unqualified certification to the NYSE with respect to the Company's compliance with the NYSE Corporate Governance listing standards on July 18, 2013.

ITEM 11. EXECUTIVE COMPENSATION

Information required by this item is incorporated by reference to such information as set forth in the Range Proxy Statement for the 2014 Annual Meeting of Stockholders.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information required by this item is incorporated by reference to such information as set forth in the Range Proxy Statement for the 2014 Annual Meeting of Stockholders.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

Information required by this item is incorporated by reference to such information as set forth in the Range Proxy Statement for the 2014 Annual Meeting of Stockholders.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information required by this item is incorporated by reference to such information as set forth in the Range Proxy Statement for the 2014 Annual Meeting of Stockholders.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) Documents filed as part of the report:

1. Financial Statements:

2. All other schedules are omitted because they are not applicable, not required, or because the required information is included in the financial statements or related notes.

3. Exhibits:

(a) See Index of Exhibits on page 67 for a description of the exhibits filed as a part of this report.

GLOSSARY OF CERTAIN DEFINED TERMS

The terms defined in this glossary are used in this report.

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

Bcf. One billion cubic feet of gas.

Bcfe. One billion cubic feet of natural gas equivalents, based on a ratio of 6 mcf for each barrel of oil or NGL, which reflects relative energy content.

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

dry hole. A well found to be incapable of producing oil or natural gas in sufficient economic quantities.

exploratory well. A well drilled to find oil or gas in an unproved area, to find a new reservoir in an existing field previously found to be productive of oil and gas in another reservoir or to extend a known reservoir.

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

Mbbl. One thousand barrels of crude oil or other liquid hydrocarbons.

Mcf. One thousand cubic feet of gas.

Mcf per day. One thousand cubic feet of gas per day.

Mcfe. One thousand cubic feet of natural gas equivalents, based on a ratio of 6 mcf for each barrel of oil or NGLs, which reflects relative energy content.

Mmbbl. One million barrels of crude oil or other liquid hydrocarbons.

Mmbtu. One million British thermal units. A British thermal unit is the heat required to raise the temperature of one pound of water from 58.5 to 59.5 degrees Fahrenheit.

Mmcf. One million cubic feet of gas.

Mmcfe. One million cubic feet of gas equivalents.

NGLs. Natural gas liquids.

net acres or net wells. The sum of the fractional working interests owned in gross acres or gross wells.

present value (PV). The present value of future net cash flows, using a 10% discount rate, from estimated proved reserves, using constant prices and costs in effect on the date of the report (unless such prices or costs are subject to change pursuant to contractual provisions). The after tax present value is the Standardized Measure.

productive well. A well that is producing oil or gas or that is capable of production.

proved developed non-producing reserves. Reserves that consist of (i) proved reserves from wells which have been completed and tested but are not producing due to lack of market or minor completion problems which are expected to be corrected and (ii) proved reserves currently behind the pipe in existing wells and which are expected to be productive due to both the well log characteristics and analogous production in the immediate vicinity of the wells.

proved developed reserves. Proved reserves that can be expected to be recovered (i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well and (ii) through installed extracting equipment and infrastructure operational at the time of the reserve estimate if the extraction is by means not involving a well.

proved reserves. The quantities of crude oil, natural gas and NGLs that geological and engineering data can estimate with reasonable certainty to be economically producible within a reasonable time from known reservoirs under existing economic, operating and regulatory conditions prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain.

proved undeveloped reserves. Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

recompletion. The completion for production an existing well bore in another formation from that in which the well has been previously completed.

reserve life. Proved reserves at a point in time divided by the then production rate (annual or quarterly).

royalty acreage. Acreage represented by a fee mineral or royalty interest which entitles the owner to receive free and clear of all production costs a specified portion of the oil and gas produced or a specified portion of the value of such production.

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

Standardized Measure. The present value, discounted at 10%, of future net cash flows from estimated proved reserves after income taxes, calculated holding prices and costs constant at amounts in effect on the date of the report (unless such prices or costs are subject to change pursuant to contractual provisions) and otherwise in accordance with the Commission’s rules for inclusion of oil and gas reserve information in financial statements filed with the Commission.

working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and a share of production, subject to all royalties, overriding royalties and other burdens, and to all costs of exploration, development and operations, and all risks in connection therewith.

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.

RANGE RESOURCES CORPORATION

By: /s/ JEFFREY L. VENTURA

Jeffrey L. Ventura
President and Chief Executive Officer
(principal executive officer)

Dated: February 26, 2014

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 capacity and on the dates indicated.

Signature	Capacity	Date
/s/ JEFFREY L. VENTURA **Jeffrey L. Ventura**	Director, President and Chief Executive Officer (principal executive officer)	February 26, 2014
/s/ ROGER S. MANNY **Roger S. Manny**	Executive Vice President and Chief Financial Officer (principal financial officer)	February 26, 2014
/s/ DORI A. GINN **Dori A. Ginn**	Senior Vice President, Controller and Principal Accounting Officer	February 26, 2014
/s/ JOHN H. PINKERTON **John H. Pinkerton**	Director, Non-Executive Chairman of the Board	February 26, 2014
/s/ ANTHONY V. DUB **Anthony V. Dub**	Director	February 26, 2014
/s/ V. RICHARD EALES **V. Richard Eales**	Lead Independent Director	February 26, 2014
/s/ ALLEN FINKELSON **Allen Finkelson**	Director	February 26, 2014
/s/ JAMES M. FUNK **James M. Funk**	Director	February 26, 2014
/s/ JONATHAN S. LINKER **Jonathan S. Linker**	Director	February 26, 2014
/s/ MARY RALPH LOWE **Mary Ralph Lowe**	Director	February 26, 2014
/s/ KEVIN S. MCCARTHY **Kevin S. McCarthy**	Director	February 26, 2014

RANGE RESOURCES CORPORATION

INDEX TO FINANCIAL STATEMENTS

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

To the Stockholders of
Range Resources Corporation:

Management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934). Our internal control over financial reporting is designed to provide reasonable assurance to management and the board of directors regarding the preparation and fair presentation of published financial statements. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Management assessed the effectiveness of our internal control over financial reporting as of December 31, 2013. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control – Integrated Framework (1992).* Based on our assessment, we believe that, as of December 31, 2013, our internal control over financial reporting is effective based on those criteria.

Ernst and Young, LLP, the independent registered public accounting firm that audited our financial statements included in this annual report, has issued an attestation report on our internal control over financial reporting as of December 31, 2013. This report appears on the following page.

By: /s/ JEFFREY L. VENTURA
Jeffrey L. Ventura
President and Chief Executive Officer

By: /s/ ROGER S. MANNY
Roger S. Manny
Executive Vice President and Chief Financial Officer

Fort Worth, Texas
February 26, 2014

REPORT OF INDEPENDENT REGISTERED PUBLIC

ACCOUNTING FIRM ON INTERNAL CONTROL OVER FINANCIAL REPORTING

To the Board of Directors and Stockholders of
Range Resources Corporation:

We have audited Range Resources Corporation's internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (1992 framework) (the COSO criteria). Range Resources Corporation'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 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 its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that 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, Range Resources Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Range Resources Corporation as of December 31, 2013 and 2012 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, 2013 and our report dated February 26, 2014 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Fort Worth, Texas
February 26, 2014

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Range Resources Corporation:

We have audited the accompanying consolidated balance sheets of Range Resources Corporation (the "Company") as of December 31, 2013 and 2012, 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, 2013. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated 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, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Range Resources Corporation at December 31, 2013 and 2012, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2013, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Range Resources Corporation's internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (1992 framework) and our report dated February 26, 2014 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Fort Worth, Texas
February 26, 2014

RANGE RESOURCES CORPORATION
CONSOLIDATED BALANCE SHEETS
(In thousands, except share data)

	December 31, 2013	December 31, 2012
Assets		
Current assets:		
Cash and cash equivalents	$ 348	$ 252
Accounts receivable, less allowance for doubtful accounts of $2,494 and $2,374	179,667	167,495
Derivative assets	4,421	137,552
Deferred tax assets	51,414	—
Inventory and other	12,451	22,315
Total current assets	248,301	327,614
Derivative assets	9,233	15,715
Equity method investments	129,034	132,449
Natural gas and oil properties, successful efforts method	9,032,881	8,111,775
Accumulated depletion and depreciation	(2,274,444)	(2,015,591)
	6,758,437	6,096,184
Transportation and field assets	118,625	117,717
Accumulated depreciation and amortization	(85,841)	(76,150)
	32,784	41,567
Other assets	121,297	115,206
Total assets	$ 7,299,086	$ 6,728,735
Liabilities		
Current liabilities:		
Accounts payable	$ 258,431	$ 234,651
Asset retirement obligations	5,037	2,470
Accrued liabilities	161,520	139,379
Deferred tax liability	—	37,924
Accrued interest	44,375	36,248
Derivative liabilities	26,198	4,471
Total current liabilities	495,561	455,143
Bank debt	500,000	739,000
Subordinated notes	2,640,516	2,139,185
Deferred tax liability	771,980	698,302
Derivative liabilities	25	3,463
Deferred compensation liability	247,537	187,604
Asset retirement obligations and other liabilities	229,015	148,646
Total liabilities	4,884,634	4,371,343
Commitments and contingencies		
Stockholders' Equity		
Preferred stock, $1 par 10,000,000 shares authorized, none issued and outstanding	—	—
Common stock, $0.01 par 475,000,000 shares authorized, 163,441,414 issued at December 31, 2013 and 162,641,896 issued at December 31, 2012	1,634	1,626
Common stock held in treasury, 98,520 shares at December 31, 2013 and 127,798 shares at December 31, 2012	(3,637)	(4,760)
Additional paid-in capital	1,959,636	1,915,627
Retained earnings	450,583	360,990
Accumulated other comprehensive income	6,236	83,909
Total stockholders' equity	2,414,452	2,357,392
Total liabilities and stockholders' equity	$ 7,299,086	$ 6,728,735

See accompanying notes.

RANGE RESOURCES CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands, except per share data)

	Year Ended December 31,		
	2013	2012	2011
Revenues and other income:			
Natural gas, NGLs and oil sales	$ 1,715,676	$ 1,351,694	$ 1,173,266
Derivative fair value (loss) income	(61,825)	41,437	40,087
Gain on the sale of assets	92,291	49,132	2,259
Brokered natural gas, marketing and other	116,577	15,441	15,030
Total revenues and other income	1,862,719	1,457,704	1,230,642
Costs and expenses:			
Direct operating	128,091	115,905	112,972
Transportation, gathering and compression	256,242	192,445	120,755
Production and ad valorem taxes	45,240	67,120	27,666
Brokered natural gas and marketing	131,786	20,434	11,986
Exploration	64,409	69,807	81,367
Abandonment and impairment of unproved properties	51,918	125,278	79,703
General and administrative	291,171	173,813	151,191
Deferred compensation plan	55,296	7,203	43,209
Interest expense	176,557	168,798	125,052
Loss on early extinguishment of debt	12,280	11,063	18,576
Depletion, depreciation and amortization	492,397	445,228	341,221
Impairment of proved properties and other assets	7,753	35,554	38,681
Total costs and expenses	1,713,140	1,432,648	1,152,379
Income from continuing operations before income taxes	149,579	25,056	78,263
Income tax expense (benefit)			
Current	(143)	(1,778)	637
Deferred	34,000	13,832	34,920
	33,857	12,054	35,557
Income from continuing operations	115,722	13,002	42,706
Discontinued operations, net of taxes	—	—	15,320
Net income	$ 115,722	$ 13,002	$ 58,026
Net income per common share:			
Basic - income from continuing operations	$ 0.71	$ 0.08	$ 0.26
- discontinued operations	—	—	0.10
- net income	$ 0.71	$ 0.08	$ 0.36
Diluted - income from continuing operations			
- discontinued operations	$ 0.70	$ 0.08	$ 0.26
- net income	—	—	0.10
	$ 0.70	$ 0.08	$ 0.36
Weighted average common shares outstanding:			
Basic	160,438	159,431	158,030
Diluted	161,407	160,307	159,441

See accompanying notes.

RANGE RESOURCES CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(In thousands)

	December 31,		
	2013	**2012**	**2011**
Net income	$ 115,722	$ 13,002	$ 58,026
Other comprehensive income:			
Realized (gain) loss on hedge derivative contract settlements reclassified into natural gas, NGLs and oil sales from other comprehensive income, net of taxes [1]	(14,840)	(144,434)	(82,196)
De-designated hedges reclassified into natural gas, NGLs and oil sales, net of taxes [2]	(56,254)	—	—
De-designated hedges reclassified to derivative fair value income, net of taxes [3]	(2,376)	—	—
Change in unrealized deferred hedging (losses) gains, net of taxes [4]	(4,203)	71,716	171,353
Total comprehensive income (loss)	$ 38,049	$ (59,716)	$ 147,183

(1) Amounts are net of income tax benefit of $9,488 for the year ended December 31, 2013 compared to $91,871 for the year ended December 31, 2012 and $50,005 for the year ended December 31, 2011.

(2) Amounts are net of income tax benefit of $35,968 for the year ended December 31, 2013.

(3) Amounts relate to transactions not probable of occurring and are presented net of income tax benefit of $1,517 for the year ended December 31, 2013.

(4) Amounts are net of income tax benefit of $2,687 for the year ended December 31, 2013 compared to income tax expense of $47,466 for the year ended December 31, 2012 and income tax expense of $104,464 for the twelve months ended December 31, 2011.

See accompanying notes.

RANGE RESOURCES CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	Year Ended December 31,		
	2013	2012	2011
Operating activities:			
Net income	$ 115,722	$ 13,002	$ 58,026
Adjustments to reconcile net income to net cash provided from operating activities:			
Gain from discontinued operations	—	—	(15,320)
(Gain) loss from equity method investments, net of distributions	(2,973)	5,670	16,871
Deferred income tax expense	34,000	13,832	34,920
Depletion, depreciation and amortization and impairment	500,150	480,782	379,902
Exploration dry hole costs	5,699	841	3,888
Abandonment and impairment of unproved properties	51,918	125,278	79,703
Derivative fair value loss (income)	61,825	(41,437)	(40,087)
Cash settlements on derivative financial instruments that do not qualify for hedge accounting	(31,256)	38,700	22,142
Allowance for bad debt	250	750	946
Amortization of deferred financing costs, loss on extinguishment of debt and other	23,866	23,165	25,458
Deferred and stock-based compensation	119,398	60,136	86,979
Gain on the sale of assets	(92,291)	(49,132)	(2,259)
Changes in working capital:			
Accounts receivable	(21,212)	(38,017)	(37,789)
Inventory and other	3,785	(7,376)	865
Accounts payable	(13,555)	13,654	738
Accrued liabilities and other	(11,788)	7,251	(4,783)
Net cash provided from continuing operations	743,538	647,099	610,200
Net cash provided from discontinued operations	—	—	21,437
Net cash provided from operating activities	743,538	647,099	631,637
Investing activities:			
Additions to natural gas and oil properties	(1,159,252)	(1,498,628)	(1,199,545)
Additions to field service assets	(5,925)	(4,762)	(11,607)
Acreage purchases	(132,145)	(191,065)	(226,500)
Equity method investments	3,799	—	—
Proceeds from disposal of assets	315,522	168,219	53,926
Purchases of marketable securities held by the deferred compensation plan	(36,136)	(60,406)	(25,388)
Proceeds from the sales of marketable securities held by the deferred compensation plan	30,701	58,084	20,410
Net cash used in investing activities from continuing operations	(983,436)	(1,528,558)	(1,388,704)
Net cash provided from discontinued operations	—	—	840,723
Net cash used in investing activities	(983,436)	(1,528,558)	(547,981)
Financing activities:			
Borrowings on credit facilities	1,684,000	1,773,000	887,826
Repayments on credit facilities	(1,923,000)	(1,221,000)	(974,826)
Issuance of subordinated notes	750,000	600,000	500,000
Repayment of subordinated notes	(259,063)	(259,375)	(413,697)
Dividends paid	(26,129)	(25,981)	(25,756)
Debt issuance costs	(12,448)	(12,605)	(22,003)
Issuance of common stock	343	2,073	619
Change in cash overdrafts	5,610	(1,126)	(51,474)
Proceeds from the sales of common stock held by the deferred compensation plan	20,681	26,633	12,899
Net cash provided from (used in) financing activities	239,994	881,619	(86,412)
Increase (decrease) in cash and cash equivalents	96	160	(2,756)
Cash and cash equivalents at beginning of year	252	92	2,848
Cash and cash equivalents at end of year	$ 348	$ 252	$ 92

See accompanying notes.

RANGE RESOURCES CORPORATION
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(In thousands, except per share data)

	Common stock		Common stock held in	Additional paid-in capital	Retained earnings	Accumulated other comprehensive income (loss)	Total
	Shares	Par value	treasury				
Balance as of December 31, 2010	160,114	$ 1,601	$ (7,512)	$ 1,820,503	$ 341,699	$ 67,470	**$ 2,223,761**
Issuance of common stock	1,189	12	—	8,870	—	—	**8,882**
Stock-based compensation expense	—	—	—	26,674	—	—	**26,674**
Tax benefit of stock compensation	—	—	—	11,676	—	—	**11,676**
Common dividends declared ($0.16 per share)	—	—	—	—	(25,756)	—	**(25,756)**
Treasury stock issuance	—	—	1,169	(1,169)	—	—	**—**
Other comprehensive income	—	—	—	—	—	89,157	**89,157**
Net income	—	—	—	—	58,026	—	**58,026**
Balance as of December 31, 2011	161,303	1,613	(6,343)	1,866,554	373,969	156,627	**2,392,420**
Issuance of common stock	1,339	13	—	20,251	—	—	**20,264**
Stock-based compensation expense	—	—	—	30,405	—	—	**30,405**
Common dividends declared ($0.16 per share)	—	—	—	—	(25,981)	—	**(25,981)**
Treasury stock issuance	—	—	1,583	(1,583)	—	—	**—**
Other comprehensive loss	—	—	—	—	—	(72,718)	**(72,718)**
Net income	—	—	—	—	13,002	—	**13,002**
Balance as of December 31, 2012	162,642	1,626	(4,760)	1,915,627	360,990	83,909	**2,357,392**
Issuance of common stock	799	8	—	9,281	—	—	**9,289**
Stock-based compensation expense	—	—	—	35,851	—	—	**35,851**
Common dividends declared ($0.16 per share)	—	—	—	—	(26,129)	—	**(26,129)**
Treasury stock issuance	—	—	1,123	(1,123)	—	—	**—**
Other comprehensive loss	—	—	—	—	—	(77,673)	**(77,673)**
Net income	—	—	—	—	115,722	—	**115,722**
Balance as of December 31, 2013	163,441	$ 1,634	$ (3,637)	$ 1,959,636	$ 450,583	$ 6,236	**$ 2,414,452**

See accompanying notes.

RANGE RESOURCES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) SUMMARY OF ORGANIZATION AND NATURE OF BUSINESS

Range Resources Corporation ("Range," "we," "us," or "our") is a Fort Worth, Texas-based independent natural gas and oil company primarily engaged in the exploration, development and acquisition of natural gas and oil properties in the Appalachian and Southwestern regions of the United States. Our objective is to build stockholder value through consistent growth in reserves and production on a cost-efficient basis. Range is a Delaware corporation with our common stock listed and traded on the New York Stock Exchange under the symbol "RRC."

(2) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation and Principles of Consolidation

The accompanying consolidated financial statements include the accounts of all of our subsidiaries. Investments in entities over which we have significant influence, but not control, are accounted for using the equity method of accounting and are carried at our share of net assets plus loans and advances. Income from equity method investments represents our proportionate share of income generated by equity method investees and is included in brokered natural gas, marketing and other revenues in the accompanying consolidated statements of operations. All material intercompany balances and transactions have been eliminated.

Discontinued Operations

During February 2011, we entered into an agreement to sell our Barnett Shale assets. In April 2011, we completed the sale of most of these assets and closed the remainder of the sale in August 2011. We have classified the historical results of the operations from such properties as discontinued operations, net of tax, in the accompanying statements of operations. For more information regarding the sale of our Barnett Shale assets, see Notes 3 and 4 . Unless otherwise indicated, the information in these notes relate to our continuing operations.

Use of Estimates

The preparation of financial statements in accordance with generally accepted accounting principles in the United States requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at year-end, and the reported amounts of revenues and expenses during the reporting period. Depletion of natural gas and oil properties is determined using estimates of proved oil and gas reserves. Our assessment of the recoverability of our proved natural gas and oil properties and any assessment of impairment thereof is based on using estimates of proved, probable and possible oil and gas reserves. There are numerous uncertainties inherent in the estimation of quantities of oil and gas reserves and in the projection of future rates of production and the timing of development expenditures. Similarly, evaluation of unproved natural gas and oil properties are subject to numerous uncertainties, including, among others, estimates of future recoverable reserves and commodity price outlook. We base our estimates on historical experience and various other assumptions that we believe are reasonable under the circumstances, the results of which form the basis for making judgments that are not readily apparent from other sources. Actual results could differ from these estimates and changes in these estimates are recorded when known.

Reclassifications

Certain reclassifications have been made to prior years' reported amounts in order to conform with the current year presentation, which includes reclassifications between accounts receivable and accrued liabilities within cash flow from operating activities and a change in the presentation for our derivative activities. These reclassifications did not impact our net income from continuing operations, net income, stockholders' equity or cash flows.

Business Segment Information

We have evaluated how we are organized and managed and have identified only one operating segment, which is the exploration and production of natural gas, NGLs and oil in the United States. We consider our gathering, processing and marketing functions as ancillary to our natural gas and oil producing activities. Operating segments are defined as components of an enterprise that engage in activities from which it may earn revenues and incur expenses for which separate operational financial information is available and this information is regularly evaluated by the chief operating decision maker for the purpose of allocating resources and assessing performance.

We have a single company-wide management team that administers all properties as a whole rather than by discrete operating segments. We track only basic operational data by area. We do not maintain complete separate financial statement information by area. We measure financial performance as a single enterprise and not on an area-by-area basis. Throughout the year, we allocate capital resources on a project-by-project basis, across our entire asset base to maximize profitability without regard to individual areas.

Revenue Recognition, Accounts Receivable and Gas Imbalances

Natural gas, NGLs and oil sales are recognized when we deliver our production to the customer and collectability is reasonably assured. We generally sell natural gas, NGLs and oil under two types of agreements, which are common in our industry. Both types of agreements include transportation charges. We are reporting our gathering and transportation costs in accordance with Financial Accounting Standard Board ("FASB") Section 605-45-05 of Subtopic 605-45 for Revenue Recognition. One type of agreement is a netback arrangement, under which we sell natural gas and oil at the wellhead and collect a price, net of transportation incurred by the purchaser. In this case, we record revenue at the price we received from the purchaser. In the case of NGLs, we receive a net price from the purchaser (which is net of processing costs) which is also recorded in revenue at the net price we receive from the purchaser. Under the other arrangement, we sell natural gas or oil at a specific delivery point, pay transportation, gathering and compression expenses to a third party and receive proceeds from the purchaser with no deduction. In that case, we record revenue at the price received from the purchaser and record the expenses we incur as transportation, gathering and compression expense. We realize brokered margins as a result of buying and selling natural gas utilizing separate purchase and sale transactions, typically with separate counterparties. The amount of brokered margin was immaterial in both 2012 and 2011. In 2013, we purchased (and sold) natural gas which was used to blend our rich residue gas from the Southwest Marcellus Shale. Our brokered margin was a loss of $5.7 million in 2013.

Although receivables are concentrated in the oil and gas industry, we do not view this as an unusual credit risk. We provide for an allowance for doubtful accounts for specific receivables judged unlikely to be collected based on the age of the receivable, our experience with the debtor, potential offsets to the amount owed and economic conditions. In certain instances, we require purchasers to post stand-by letters of credit. Many of our receivables are from joint interest owners of properties we operate. Thus, we may have the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings. We have allowances for doubtful accounts relating to exploration and production receivables of $2.5 million at December 31, 2013 compared to $2.4 million at December 31, 2012. During the year ended 2013, we recorded bad debt expense of $250,000 compared to $750,000 in 2012 and $946,000 in 2011.

Revenues from the production of natural gas, NGLs and oil on properties in which we have joint ownership are recorded under the sales method. Under the sales method, we and other joint owners may sell more or less than our entitled share of production. Should our sales exceed our share of remaining reasonable reserves, a liability is recorded. At December 31, 2013, we had recorded a net liability of $482,000 for those wells where it was determined that there were insufficient reserves to recover the imbalance.

Cash and Cash Equivalents

Cash and cash equivalents include cash on hand and on deposit and investments in highly liquid debt instruments with maturities of three months or less.

Marketable Securities

Investments in unaffiliated equity securities held in our deferred compensation plans qualify as trading securities and are recorded at fair value. Investments held in the deferred compensation plans consist of various publicly-traded mutual funds. These funds are made up of investments, which include equity securities and money market instruments.

Inventory

Inventories were comprised of $9.6 million of materials and supplies at December 31, 2013 compared to $16.3 million at December 31, 2012. Inventories consist primarily of tubular goods used in our operations and are stated at the lower of specific cost of each inventory item or market, on a first-in, first-out basis. Our material and supplies inventory is primarily acquired for use in future drilling operations or repair operations. At December 31, 2012, we also had commodity inventory of $2.6 million, which was carried at lower of average cost or market, on a first-in, first-out basis. We have no commodity inventory as of December 31, 2013.

Natural Gas and Oil Properties

Property Acquisition Costs

We use the successful efforts method of accounting for natural gas and oil producing activities. Costs to drill exploratory wells that do not find proved reserves, geological and geophysical costs, delay rentals and costs of carrying and retaining unproved properties are expensed. Costs incurred for exploratory wells that find reserves that cannot yet be classified as proved are capitalized if (a) the well has found a sufficient quantity of reserves to justify its completion as a producing well and (b) we are making sufficient progress assessing the reserves and the economic and operating viability of the project. The status of suspended well costs is monitored continuously and reviewed not less than quarterly. We capitalize successful exploratory wells and all developmental wells, whether successful or not. Due to the capital-intensive nature and the geographical location of certain projects, it may take an extended period of time to evaluate the future potential of an exploration project and the economics associated with making a determination on its commercial viability. In these instances, the project's feasibility is not contingent upon price improvements or advances in technology, but rather our ongoing efforts and expenditures related to accurately predicting the hydrocarbon recoverability based on well information, gaining access to other companies' production data in the area, transportation or processing facilities and/or obtaining partner approval to drill additional appraisal wells. These activities are ongoing and are being pursued constantly. Consequently, our assessment of suspended exploratory well costs is continuous until a decision can be made that the project has found proved reserves to sanction the project or is noncommercial and is charged to exploration expense. For more information regarding suspended exploratory well costs, see Note 7.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization of proved producing properties is provided on the units of production method. Historically, we have adjusted our depletion rates in the fourth quarter of each year based on the year-end reserve report and at other times during the year when circumstances indicate there has been a significant change in reserves or costs.

Impairments

Our proved natural gas and oil properties are reviewed for impairment periodically as events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. These assets are reviewed for potential impairment at the lowest level for which there are identifiable cash flows that are largely independent of other groups of assets which is the level at which depletion is calculated. The review is done by determining if the historical cost of proved properties less the applicable accumulated depreciation, depletion and amortization is less than the estimated expected undiscounted future net cash flows. The expected future net cash flows are estimated based on our plans to produce and develop reserves. Expected future net cash inflow from the sale of produced reserves is calculated based on estimated future prices and estimated operating and development costs. We estimate prices based upon market-related information including published futures prices. The estimated future level of production, which is based on proved and risk adjusted probable and possible reserves, has assumptions surrounding the future levels of prices and costs, field decline rates, market demand and supply, and the economic and regulatory climate. In certain circumstances, we also consider potential sales of properties to third parties in our estimates of cash flows. When the carrying value exceeds the sum of future net cash flows, an impairment loss is recognized for the difference between the estimated fair market value (as determined by discounted future net cash flows using a discount rate similar to that used by market participants) and the carrying value of the asset. A significant amount of judgment is involved in performing these evaluations since the results are based on estimated future events. Such events include a projection of future natural gas and oil prices, an estimate of the ultimate amount of recoverable natural gas and oil reserves that will be produced from an asset group, the timing of future production, future production costs, future abandonment costs and future inflation. We cannot predict whether impairment charges may be required in the future. If natural gas, NGLs and oil prices decrease or drilling efforts are unsuccessful, we may be required to record additional impairments. For additional information regarding proved property impairments, see Note 12.

We evaluate our unproved property investment periodically for impairment. The majority of these costs generally relate to the acquisition of leasehold costs. The costs are capitalized and evaluated (at least quarterly) as to recoverability, based on changes brought about by economic factors and potential shifts in business strategy employed by management. Impairment of a significant portion of our unproved properties is assessed and amortized on an aggregate basis based on our average holding period, expected forfeiture rate and anticipated drilling success. Impairment of individually significant unproved property is assessed on a property-by-property basis considering a combination of time, geologic and engineering factors. Unproved properties had a net book value of $807.0 million as of December 31, 2013 compared to $743.5 million in 2012. We have recorded abandonment and impairment expense related to unproved properties from continuing operations of $51.9 million in 2013 compared to $125.3 million in 2012 and to $79.7 million in 2011.

Dispositions

Proceeds from the disposal of natural gas and oil producing properties that are part of an amortization base are credited to the net book value of the amortization group with no immediate effect on income. However, gain or loss is recognized if the disposition is significant enough to materially impact the depletion rate of the remaining properties in the amortization base.

Acquisitions

Acquisitions are accounted for as business combinations and, accordingly, the results of operations are included in the accompanying statements of operations from the closing date of the acquisition. Purchase prices are allocated to acquired assets and assumed liabilities based on their estimated fair value at the time of the acquisition. In the past, acquisitions have been funded with internal cash flow, bank borrowings and the issuance of debt and equity securities.

Transportation and Field Assets

Our gas transportation and gathering systems are generally located in proximity to certain of our principal fields. Depreciation on these pipeline systems is provided on the straight-line method based on estimated useful lives of ten to fifteen years. We receive third-party income for providing field service and certain transportation services, which is recognized as earned. Depreciation on the associated assets is calculated on the straight-line method based on estimated useful lives ranging from five to seven years. Transportation and field assets also includes other property and equipment such as buildings, furniture and fixtures, leasehold improvements and data processing and communication equipment. These items are generally depreciated by individual components on a straight-line basis over their economic useful life, which is generally from three to fifteen years. Leasehold improvements are amortized over the lesser of their economic useful lives or the underlying terms of the associated leases. Depreciation expense was $13.2 million in 2013 compared to $13.2 million in 2012 and $16.2 million in 2011.

Other Assets

The expenses of issuing debt are capitalized and included in other assets in the accompanying consolidated balance sheets. These costs are amortized over the expected life of the related instruments. When debt is retired before maturity or modifications significantly change the cash flows, the related unamortized costs are expensed. Other assets at December 31, 2013 include $44.5 million of unamortized debt issuance costs, $67.8 million of marketable securities held in our deferred compensation plans and $9.0 million of other investments including surface acreage. Other assets at December 31, 2012 include $43.1 million of unamortized debt issuance costs, $57.8 million of marketable securities held in our deferred compensation plans and $14.3 million of other investments including surface acreage.

Accounts Payable

Included in accounts payable at December 31, 2013 and 2012, are liabilities of approximately $50.2 million and $44.6 million representing the amount by which checks issued, but not presented to our banks for collection, exceeded balances in our applicable bank accounts.

Stock-based Compensation Arrangements

The fair value of stock options and stock-settled stock appreciation rights (“SARs”) is estimated on the date of grant using the Black-Scholes-Merton option-pricing model. The model employs various assumptions, based on management’s best estimates at the time of the grant, which impact the fair value calculated and ultimately, the expense that is recognized over the life of the award. We have utilized historical data and analyzed current information to reasonably support these assumptions. The fair value of restricted stock awards (“Liability Awards”) and restricted stock unit awards (“Equity Awards”) is determined based on the fair market value of our common stock on the date of grant.

We recognize stock-based compensation expense on a straight-line basis over the requisite service period for the entire award. The expense we recognize is net of estimated forfeitures. We estimate our forfeiture rate based on prior experience and adjust it as circumstances warrant. Substantially all Liability Awards are deposited in our deferred compensation plans at the time of grant and are classified as a liability due to the fact that these awards are expected to be settled wholly or partially in cash. The fair value of the Liability Awards is updated at each balance sheet date with changes in the fair value of the vested portion of the awards recorded as increases or decreases to deferred compensation plan expense in the accompanying statements of operations.

Derivative Financial Instruments and Hedging

All of our derivative instruments are issued to manage the price risk attributable to our expected natural gas, NGLs and oil production. While there is risk that the financial benefit of rising natural gas, NGLs and oil prices may not be captured, we believe the benefits of stable and predictable cash flow are more important. Among these benefits are more efficient utilization of existing personnel and planning for future staff additions, the flexibility to enter into long-term projects requiring substantial committed capital, smoother and more efficient execution of our ongoing development drilling and production enhancement programs, more consistent returns on invested capital and better access to bank and other capital markets. All unsettled derivative instruments are recorded in the accompanying consolidated balance sheets as either an asset or a liability measured at its fair value. In most cases, our derivatives are reflected on our consolidated balance sheet on a net basis by brokerage firm, when they are governed by master netting agreements. Changes in a derivative's fair value are recognized in earnings unless specific hedge accounting criteria are met. Cash flows from derivative contract settlements are reflected in operating activities in the accompanying consolidated statements of cash flows.

Through February 28, 2013, we elected to designate our commodity derivative instruments that qualified for hedge accounting as cash flow hedges. To designate a derivative as a cash flow hedge, we documented at the hedge's inception our assessment that the derivative would be highly effective in offsetting expected changes in cash flows from the item hedged. This assessment, which was updated at least quarterly, was generally based on the most recent relevant historical correlation between the derivative and the item hedged. The ineffective portion of the hedge was calculated as the difference between the change in fair value of the derivative and the estimated change in cash flows from the item hedged. If, during the derivative's term, we determined the hedge was no longer highly effective, hedge accounting was prospectively discontinued and any remaining unrealized gains or losses, based on the effective portion of the derivative at that date, were reclassified to earnings as natural gas, NGLs and oil sales when the underlying transaction occurred. If it was determined that the designated hedged transaction was probable to not occur, any unrealized gains or losses were recognized immediately in derivative fair value in the accompanying consolidated statements of operations. In 2013, we recognized $3.9 million in derivative fair value as a result of the discontinuance of hedge accounting when we determined the transaction was probable not to occur due, in part, to the sale of our Delaware and Permian Basin properties in Southeast New Mexico and West Texas. In 2012 and 2011, we did not transfer any gains or losses into derivative fair value as a result of discontinuing hedge accounting.

Through February 28, 2013, we applied hedge accounting to qualifying derivatives (or "hedge derivatives") used to manage price risk associated with our natural gas, NGLs and oil production. Accordingly, we recorded changes in the fair value of our hedge derivatives, including changes associated with time value, in accumulated other comprehensive income ("AOCI") in the stockholders' equity section of the accompanying consolidated balance sheets. Gains or losses on these hedge derivatives were reclassified out of AOCI and into natural gas, NGLs and oil sales when the underlying physical transaction and the hedging contract settled. Any hedge ineffectiveness associated with a contract qualifying and designated as a cash flow hedge (which represents the amount by which the change in the fair value of the derivative differs from the change in the cash flows of the forecasted sale of production) was reported currently each period in derivative fair value on the accompanying consolidated statement of operations. Ineffectiveness can be associated with open positions or with closed contracts.

Effective March 1, 2013, we elected to discontinue hedge accounting prospectively. After March 1, 2013, both realized and unrealized gains and losses have been recognized in earnings in derivative fair value as derivative contracts are settled and marked to market. For more information see, Note 11.

Realized and unrealized gains and losses on derivatives that are not designated as hedges (or "non-hedge derivatives") are accounted for using the mark-to-market accounting method. We recognize all unrealized and realized gains and losses related to these contracts in each period in derivative fair value in the accompanying consolidated statements of operations. At times, we have also entered into basis swap agreements, which do not qualify for hedge accounting and are marked to market. The price we receive for our gas production can be more or less than the NYMEX price because of adjustments for delivery location ("basis"), relative quality and other factors; therefore, we have entered into basis swap agreements that effectively fix our basis adjustments.

From time to time, we may enter into derivative contracts and pay or receive premium payments at the inception of the derivative contract which represent the fair value of the contract at its inception. These amounts would be included within the net derivative asset or liability on our consolidated balance sheet. The amounts paid or received for derivative premiums reduce or increase the amounts of gains and losses that are recorded in the earnings each period as the derivative contracts settle. We have not acquired any hedges through a business combination and have not modified any existing derivative contracts.

Concentrations of Credit Risk

As of December 31, 2013, our primary concentrations of credit risk are the risks of collecting accounts receivable and the risk of counterparties' failure to perform under derivative contracts. Most of our receivables are from a diverse group of companies, including major energy companies, pipelines companies, local distribution companies, financial institutions and end-users in various industries. To manage risks of collecting accounts receivable, we monitor our counterparties financial strength and/or credit ratings and where we deem necessary, obtain letters of credit or other credit enhancements to reduce risk of loss. Our allowance for uncollectible receivables was \$2.5 million at December 31, 2013 compared to \$2.4 million at December 31, 2012.

We have executed International Swap Dealers Association Master Agreements ("ISDA Agreements") with counterparties for the purpose of entering into derivative contracts. To manage counterparty risk associated with our derivatives, we select and monitor counterparties based on assessment of their financial strength and/or credit ratings. We may also limit the level of exposure with any single counterparty. Additionally, the terms of our ISDA Agreements provide us and our counterparties with netting rights such that we may offset payables against receivables with a counterparty under separate derivative contracts. Our ISDA Agreements also generally contain set-off rights such that, upon the occurrence of defined acts of default by either us or a counterparty to a derivative contract, the non-defaulting party may set off receivables owed under all derivative contracts against payables from other agreements with that counterparty. None of our derivative contracts have margin requirements or collateral provisions that would require Range to fund or post additional collateral prior to the scheduled cash settlement date.

At December 31, 2013, our derivative counterparties included thirteen financial institutions, of which all but two are secured lenders in our bank credit facility. At December 31, 2013, our net derivative liability includes a payable to two counterparties not included in our bank credit facility totaling \$11.7 million. In determining fair value of derivative assets, we evaluate the risk of non-performance and incorporate factors such as amounts owed under other agreements permitting set off, as well as pricing of credit default swaps for the counterparty. Net derivative liabilities are determined in part by using our market based credit spread to incorporate Range's theoretical risk of non-performance.

Asset Retirement Obligations

The fair value of asset retirement obligations is recognized in the period they are incurred, if a reasonable estimate of fair value can be made. Asset retirement obligations primarily relate to the abandonment of natural gas and oil producing facilities and include costs to dismantle and relocate or dispose of production platforms, gathering systems, wells and related structures. Estimates are based on historical experience of plugging and abandoning wells, estimated remaining lives of those wells based on reserve estimates, external estimates of the cost to plug and abandon the wells in the future and federal and state regulatory requirements. Depreciation of capitalized asset retirement costs will generally be determined on a units-of-production basis while accretion to be recognized will escalate over the life of the producing assets.

Environmental Costs

Environmental expenditures are capitalized if the costs mitigate or prevent future contamination or if the costs improve environmental safety or efficiency of the existing assets. Expenditures that relate to an existing condition caused by past operations that have no future economic benefits are expensed.

Deferred Taxes

Deferred tax assets and liabilities are recognized for the estimated future tax consequences attributable to the differences between the financial statement carrying amounts of assets and liabilities and their tax bases as reported in our filings with the respective taxing authorities. Deferred tax assets are recorded when it is more likely than not that they will be realized. The realization of deferred tax assets is assessed periodically based on several interrelated factors. These factors include our expectation to generate sufficient taxable income in the periods before tax credits and operating loss carryforwards expire. We do not recognize a deferred tax asset for excess tax benefits on equity compensation that have not been realized due to our net operating loss tax position for federal or state tax purposes.

Accumulated Other Comprehensive Income

The following details the components of AOCI and related tax effects for the three years ended December 31, 2013. Amounts included in AOCI exclusively relate to our derivative activity (in thousands).

	Gross	Tax Effect	Net of Tax
Accumulated other comprehensive income at December 31, 2010	$ 111,062	$ (43,592)	$ 67,470
Contract settlements reclassified to income	(132,201)	50,005	(82,196)
Change in unrealized deferred hedging gains	275,817	(104,464)	171,353
Accumulated other comprehensive income at December 31, 2011	254,678	(98,051)	156,627
Contract settlements reclassified to income	(236,305)	91,871	(144,434)
Change in unrealized deferred hedging gains	119,182	(47,466)	71,716
Accumulated other comprehensive income at December 31, 2012	137,555	(53,646)	83,909
Contract settlements reclassified to income	(120,443)	46,973	(73,470)
Change in unrealized deferred hedging losses	(6,890)	2,687	(4,203)
Accumulated other comprehensive income at December 31, 2013	$ 10,222	$ (3,986)	$ 6,236

Accounting Pronouncements Implemented

Recently Adopted

In December 2011, an accounting standards update designed to enhance disclosures about offsetting assets and liabilities was issued. Further clarification limiting the scope of these disclosures to derivatives, repurchase agreements and reverse repurchase agreements, and securities borrowing and securities lending transactions was issued in January 2013. The disclosures are intended to enable financial statements users to evaluate the effect or potential effect of netting arrangements on an entity's financial position. Entities are required to disclosure both gross information and net information about in-scope financial instruments that are either offset in the statements of financial position or subject to an enforceable master netting arrangement or similar agreement, irrespective of whether they are offset. The accounting standards update was effective for us beginning first quarter 2013 and we include the required disclosures in Note 11. Adoption of this standard did not have a significant impact on our consolidated results of operations, financial position or cash flows.

In February 2013, an accounting standards update was issued to improve the reporting of reclassifications out of AOCI. This standard requires an entity to provide information about the amounts reclassified out of AOCI by component. In addition, an entity is required to present, either on the face of the statement where net income is presented or in the notes, significant amounts reclassified out of AOCI by the respective line items of net income but only if the amount reclassified is required under United States generally accepted accounting principles ("U.S. GAAP") to be reclassified to net income in its entirety in the same reporting period. For other amounts that are not required under U.S. GAAP to be reclassified in their entirety to net income, an entity is required to cross-reference to other disclosures required under U.S. GAAP that provide additional detail about those amounts. This accounting standards update was effective for us beginning first quarter 2013. Adoption of this standard did not have a significant impact on our consolidated results of operations, financial position or cash flows.

In June 2013, the FASB ratified the Emerging Issues Task Force consensus on Issue 13-C, which requires that an unrecognized tax benefit or a portion of an unrecognized tax benefit be presented as a reduction to a deferred tax asset for an available net operating loss carryforward, a similar tax loss or tax credit carryforward. This accounting standards update is effective for us beginning in first quarter 2014 and should be applied prospectively to unrecognized tax benefits that exists as of the effective date. Early adoption and retrospective application are permitted. We adopted these new requirements in fourth quarter 2013 and there was no significant impact on our consolidated results of operations, financial position or cash flows.

Accounting Pronouncements Not Yet Adopted

In February 2013, an accounting standards update was issued to provide guidance for the recognition, measurement, and disclosure of obligations resulting from joint and several liability arrangements for which the total amount of the obligation is fixed at the reporting date, except for obligations such as asset retirement and environmental obligations, contingencies, guarantees, income taxes and retirement benefits, which are separately addressed within U.S. GAAP. An entity is required to measure obligations resulting from joint and several liability arrangements for which the total amount of the obligation is fixed at the reporting date as the sum of 1) the amount the entity agreed to pay on the basis of its arrangement among its co-obligors and 2) any amount the entity expects to pay on behalf of its co-obligors. Disclosure of the nature of the obligation, including how the liability arose, the relationship with other co-obligors and the terms and conditions of the arrangement is required. In addition, the total outstanding amount under the arrangement, not reduced by the effect of any amounts that may be recoverable from other entities, plus the carrying amount of any liability or receivable recognized must be disclosed. This accounting standards update is effective for us beginning in first quarter 2014 and should be applied retrospectively for those in-scope obligations resulting from joint and several liability arrangements that exist at the beginning of 2014. Early adoption is permitted. We do not expect this accounting standards update to have a significant impact on our consolidated results of operations, financial position or cash flows.

(3) DISPOSITIONS

We recognized an aggregate gain on the sale of assets in continuing operations of $92.3 million in 2013 compared to $49.1 million in 2012 and $2.3 million in 2011. The following describes the significant divestitures that are included in continuing operations.

- In April 2013, we completed the sale of our Delaware and Permian Basin properties in southeast New Mexico and West Texas for a price of $275.0 million and we recognized a pre-tax gain of $83.3 million, before selling expenses of $4.2 million.
- In November 2012, we completed the sale of our Ardmore Woodford properties in Southern Oklahoma for cash proceeds of $135.0 million and we recognized a pre-tax gain of $55.2 million related to this sale.
- During 2013, 2012 and 2011, we sold miscellaneous proved and unproved oil and gas properties, inventory, an equity method investment, surface and other property and equipment and recorded a pre-tax gain of $13.2 million in 2013, compared to a pre-tax loss of $6.1 million in 2012 and a pre-tax gain of $2.3 million in 2011.

Dispositions recorded in discontinued operations

In August 2011, we completed the sale of our Barnett Shale properties located in North Central Texas for proceeds of $889.3 million, including certain derivative contracts assumed by the buyer. We recorded a pretax gain of $4.8 million in discontinued operations related to this sale. For more information on discontinued operations, see Note 4.

(4) DISCONTINUED OPERATIONS

The following table represents the components of our Barnett Shale operations as discontinued operations for the year ended December 31, 2011 (in thousands).

	Year Ended December 31, 2011
Revenues and other income:	
Natural gas, NGLs and oil sales	$ 59,185
Gain on the sale of assets	4,771
Other	10
Total revenues and other income	63,966
Costs and expenses:	
Direct operating	10,080
Transportation, gathering and compression	5,257
Production and ad valorem taxes	1,309
Exploration	37
Interest expense [a]	14,791
Depletion, depreciation and amortization	8,894
Total costs and expenses	40,368
Income before income taxes	23,598
Income tax expense	
Current	—
Deferred	8,278
	8,278
Net income from discontinued operations	$ 15,320

[a] Interest expense is allocated to discontinued operations based on the ratio of net assets of discontinued operations to our consolidated net assets plus long-term debt.

(5) INCOME TAXES

Our income tax expense from continuing operations was $33.9 million for the year ended December 31, 2013 compared to $12.1 million in 2012 and $35.6 million in 2011. Reconciliation between the statutory federal income tax rate and our effective income tax rate is as follows:

	Year Ended December 31,		
	2013	2012	2011
Federal statutory tax rate	35.0%	35.0%	35.0%
State	(2.3)	0.7	7.0
State apportionment rate change	(14.9)	—	—
Non-deductible executive compensation	0.7	1.4	3.5
Valuation allowances	3.5	8.8	(0.4)
Other	0.6	2.2	0.3
Consolidated effective tax rate	22.6%	48.1%	45.4%

Income tax expense (benefit) attributable to income from continuing operations before income taxes consists of the following (in thousands):

	2013			2012			2011		
	Current	Deferred	Total	Current	Deferred	Total	Current	Deferred	Total
U.S. federal	$ —	$ 58,527	$ 58,527	$ —	$ 11,873	$ 11,873	$ —	$ 30,055	$ 30,055
U.S. state and local	(143)	(24,527)	(24,670)	(1,778)	1,959	181	637	4,865	5,502
Total	$ (143)	$ 34,000	$ 33,857	$ (1,778)	$ 13,832	$ 12,054	$ 637	$ 34,920	$ 35,557

Significant components of deferred tax assets and liabilities are as follows:

	December 31, 2013	December 31, 2012
	(in thousands)	
Deferred tax assets:		
Current		
Deferred compensation	$ 9,128	$ 6,192
Current portion of asset retirement obligation	1,854	961
Cumulative unrealized mark-to-market loss	15,193	—
Net operating loss carryforward	23,079	—
Other	7,937	8,896
Total current	57,191	16,049
Non-current		
Net operating loss carryforward	57,266	56,402
Deferred compensation	91,094	72,904
Equity compensation	22,800	23,363
AMT credits and other credits	4,122	2,761
Non-current portion of asset retirement obligation	86,126	56,764
Cumulative unrealized mark-to-market gain	—	(262)
Other	1,116	1,379
Valuation allowance	(14,781)	(9,052)
Total non-current	247,743	204,259
Deferred tax liabilities:		
Current		
Net unrealized gain in AOCI related to hedge derivatives	(3,987)	(49,124)
Other	(1,789)	(2,004)
Cumulative unrealized mark-to-market gain	—	(2,845)
Total current	(5,776)	(53,973)
Non-current		
Depreciation, depletion and investments	(1,010,757)	(894,031)
Cumulative unrealized mark-to-market gain	(6,424)	—
Other	(2,542)	(4,008)
Net unrealized gain in AOCI related to hedge derivatives	—	(4,522)
Total non-current	(1,019,724)	(902,561)
Net deferred tax liability	$ (720,566)	$ (736,226)

At December 31, 2013, deferred tax liabilities exceeded deferred tax assets by $720.6 million, with $4.0 million of deferred tax liability related to net deferred hedging gains included in AOCI. As of December 31, 2013, we have a $11.4 million valuation allowance on the deferred tax asset related to our deferred compensation plan for planned future distributions to certain executives to the extent that their estimated future compensation plus distribution amounts would exceed the $1.0 million deductible limit provided under I.R.C. Section 162(m). We also have a $3.0 million valuation allowance on our state net operating loss carryforwards and a $363,000 valuation allowance on a capital loss carryforward.

At December 31, 2013, we had regular net operating loss ("NOL") carryforwards of $354.2 million and alternative minimum tax ("AMT") NOL carryforwards of $304.7 million that expire between 2018 and 2033. Our deferred tax asset related to regular NOL carryforwards at December 31, 2013 was $39.0 million, which is net of the Accounting Standards Codification 718 Stock Compensation reduction for unrealized benefits, related to NOL's created by excess tax deductions that have not generated current tax benefits. We expect to utilize approximately $250 million in federal net operating loss carryforwards and $245 million in alternative minimum tax net operating loss carryforwards in 2014 and have included the tax effect of this portion of our NOL in current deferred tax assets. At December 31, 2013, we have AMT credit carryforwards of $665,000 that are not subject to limitation or expiration.

We file consolidated tax returns in the United States federal jurisdiction. We file separate company state income tax returns in Louisiana, Mississippi, Pennsylvania and Virginia and file consolidated or unitary state income tax returns in New Mexico, Oklahoma, Texas and West Virginia. We are subject to U.S. Federal income tax examinations for the years 2010 and after and we are subject to various state tax examinations for years 2009 and after. We have not extended the statute of limitation period in any income tax jurisdiction. Our policy is to recognize interest related to income tax expense in interest expense and penalties in general and administrative expense. We do not have any accrued interest or penalties related to tax amounts as of December 31, 2013. Throughout 2013, our unrecognized tax benefits were not material.

(6) INCOME PER COMMON SHARE

Basic income or loss per share attributable to common shareholders is computed as (i) income or loss attributable to common shareholders (ii) less income allocable to participating securities (iii) divided by weighted average basic shares outstanding. Diluted income or loss per share attributable to common stockholders is computed as (i) basic income or loss attributable to common shareholders (ii) plus diluted adjustments to income allocable to participating securities (iii) divided by weighted average diluted shares outstanding. The following table sets forth a reconciliation of income or loss attributable to common shareholders to basic income or loss attributable to common shareholders and to diluted income or loss attributable to common shareholders (in thousands except per share amounts):

	Year Ended December 31, 2013			Year Ended December 31, 2012			Year Ended December 31, 2011		
	Continuing Operations	Discontinued Operations	Total	Continuing Operations	Discontinued Operations	Total	Continuing Operations	Discontinued Operations	Total
Income as reported	$ 115,722	$ —	$ 115,722	$ 13,002	$ —	$ 13,002	$ 42,706	$ 15,320	$ 58,026
Participating basic earnings [(a)]	(1,975)	—	(1,975)	(460)	—	(460)	(763)	(274)	(1,037)
Basic income attributed to common shareholders	113,747	—	113,747	12,542	—	12,542	41,943	15,046	56,989
Reallocation of participating earnings [(a)]	9	—	9	—	—	—	3	2	5
Diluted income attributed to common shareholders	$ 113,756	$ —	$ 113,756	$ 12,542	$ —	$ 12,542	$ 41,946	$ 15,048	$ 56,994
Income per common share:									
Basic	$ 0.71	$ —	$ 0.71	$ 0.08	$ —	$ 0.08	$ 0.26	$ 0.10	$ 0.36
Diluted	$ 0.70	$ —	$ 0.70	$ 0.08	$ —	$ 0.08	$ 0.26	$ 0.10	$ 0.36

(a) Restricted stock Liability Awards represent participating securities because they participate in nonforfeitable dividends or distributions with common equity owners. Income allocable to participating securities represents the distributed and undistributed earnings attributable to the participating securities. Participating securities, however, do not participate in undistributed net losses.

The following table provides a reconciliation of basic weighted average common shares outstanding to diluted weighted average common shares outstanding (in thousands):

	Year Ended December 31,		
	2013	2012	2011
Denominator:			
Weighted average common shares outstanding – basic	160,438	159,431	158,030
Effect of dilutive securities:			
Director and employee SARs and restricted stock Equity Awards	969	876	1,411
Weighted average common shares outstanding – diluted	161,407	160,307	159,441

Weighted average common shares – basic excludes 2.8 million shares of restricted stock Liability Awards held in our deferred compensation plans (although all awards are issued and outstanding upon grant) at the end of December 31, 2013 compared to 2.9 million shares in each of the periods ending December 31, 2012 and 2011. SARs of 226,000, 854,000 and 795,000 shares for the years ended December 31, 2013, 2012 and 2011 were outstanding but not included in the computations of diluted net income per share because the grant prices of the SARs were greater than the average market price of the common shares and would be anti-dilutive to the computations.

(7) SUSPENDED EXPLORATORY WELL COSTS

We capitalize exploratory well costs until a determination is made that the well has either found proved reserves or that it is impaired. Capitalized exploratory well costs are presented in natural gas and oil properties in the accompanying consolidated balance sheets. If an exploratory well is determined to be impaired, the well costs are charged to exploration expense in the accompanying consolidated statements of operations. The following table reflects the changes in capitalized exploratory well costs for the year ended December 31, 2013, 2012 and 2011 (in thousands except for number of projects):

	2013	2012	2011
Balance at beginning of period	$ 57,360	$ 93,388	$ 23,908
Additions to capitalized exploratory well costs pending the determination of proved reserves	39,832	153,250	86,996
Reclassifications to wells, facilities and equipment based on determination of proved reserves	(84,840)	(184,298)	(17,516)
Divested wells	—	(4,980)	—
Capitalized exploratory well costs charged to expense	(5,388)	—	—
Balance at end of period	6,964	57,360	93,388
Less exploratory well costs that have been capitalized for a period of one year or less	—	(45,965)	(83,860)
Capitalized exploratory well costs that have been capitalized for a period greater than one year	$ 6,964	$ 11,395	$ 9,528
Number of projects that have exploratory well costs that have been capitalized for a period greater than one year	1	5	3

As of December 31, 2013, the $7.0 million of capitalized exploratory well costs that have been capitalized for more than one year is comprised of one well which is evaluating pipeline options and is in our Marcellus Shale area. The following table provides an aging of capitalized exploratory well costs that have been suspended for more than one year as of December 31, 2013 (in thousands):

	Total	2013	2012	2011
Capitalized exploratory well costs that have been capitalized for more than one year	$ 6,964	$ 110	$ 6,801	$ 53

(8) INDEBTEDNESS

We had the following debt outstanding as of the dates shown below (bank debt interest rate at December 31, 2013 is shown parenthetically) (in thousands). No interest was capitalized during 2013, 2012, and 2011:

	December 31, 2013	December 31, 2012
Bank debt (1.8%)	$ 500,000	$ 739,000
Senior subordinated notes:		
7.25% senior subordinated notes due 2018	—	250,000
8.00% senior subordinated notes due 2019, net of $9,484 and $10,815 discount, respectively	290,516	289,185
6.75% senior subordinated notes due 2020	500,000	500,000
5.75% senior subordinated notes due 2021	500,000	500,000
5.00% senior subordinated notes due 2022	600,000	600,000
5.00% senior subordinated notes due 2023	750,000	—
Total debt	$ 3,140,516	$ 2,878,185

Bank Debt

In February 2011, we entered into an amended and restated revolving bank facility, which we refer to as our bank debt or our bank credit facility, which is secured by substantially all of our assets. The bank credit facility provides for an initial commitment equal to the lesser of the facility amount or the borrowing base. On December 31, 2013, the facility amount was $1.75 billion and the borrowing base was $2.0 billion. The bank credit facility provides for a borrowing base subject to redeterminations semi-annually and for event-driven unscheduled redeterminations. Our current bank group is comprised of twenty-eight financial institutions, with no one bank holding more than 9% of the total facility. The facility amount may be increased to the borrowing base amount with twenty-day notice, subject to payment of a mutually acceptable commitment fee to those banks agreeing to participate in the facility increase. As of December 31, 2013, the outstanding balance under the bank credit facility was $500.0 million as well as $84.9 million of undrawn letters of credit leaving $1.2 billion of borrowing capacity available under the facility amount. The facility matures on February 18, 2016. Borrowings under the bank facility can either be at the Alternate Base Rate (as defined) plus a spread ranging from 0.50% to 1.5% or LIBOR borrowings at the Adjusted LIBO Rate (as defined) plus a spread ranging from 1.5% to 2.5%. The applicable spread is dependent upon borrowings relative to the borrowing base. We may elect, from time to time, to convert all or any part of our LIBOR loans to base rate loans or to convert all or any of the base rate loans to LIBOR loans. The weighted average interest rate was 2.0% for the year ended December 31, 2013 compared to 2.2% for each of the years ended December 31, 2012 and 2011. A commitment fee is paid on the undrawn balance based on an annual rate of 0.375% to 0.50%. At December 31, 2013, the commitment fee was 0.375% and the interest rate margin was 1.5% on our LIBOR loans and 0.5% on our base rate loans.

Senior Subordinated Notes

In March 2013, we issued $750.0 million aggregate principal amount of 5.00% senior subordinated notes due 2023 (the "Outstanding Notes") at par for net proceeds of $738.8 million after underwriting commissions of $11.2 million. The Outstanding Notes offering was limited to qualified institutional buyers and to Non-U.S. persons outside the United States in compliance with Rule 144A and Regulations S under the Securities Act of 1933, as amended (the "Securities Act"). On June 19, 2013, substantially all of the Outstanding Notes were exchanged for an equal principal amount of registered 5.00% senior subordinated notes due 2023 pursuant to an effective registration statement on Form S-4 filed on April 26, 2013 under the Securities Act (the "Exchange Notes"). The Exchange Notes are identical to the Outstanding Notes except that the Exchange Notes are registered under the Securities Act and do not have restrictions on transfer, registration rights or provisions for additional interest. As used in this Form 10-K, the term "5.00% Notes due 2023" refers to both the Outstanding Notes and the Exchange Notes. Interest on the 5.00% Notes due 2023 is payable semi-annually in March and September and is guaranteed by all of our subsidiary guarantors. We may redeem the 5.00% Notes due 2023, in whole or in part, at any time on or after March 15, 2018, at a redemption price of 102.5% of the principal amount as of March 15, 2018, declining to 100% on March 15, 2021 and thereafter. Before March 15, 2016, we may redeem up to 35% of the original aggregate principal amount of the 5.00% Notes due 2023 at a redemption price equal to 105% of the principal amount thereof, plus accrued and unpaid interest, if any, with the proceeds of certain equity offerings, provided that 65% of the aggregate principal amount of 5.00% Notes due 2023 remains outstanding immediately after the occurrence of such redemption and also provided such redemption shall occur within 60 days of the date of the closing of the equity offering. On closing of the 5.00% Notes due 2023, we used the proceeds to pay down our outstanding bank credit facility balance. We did not receive any proceeds from the issuance of the Exchange Notes.

If we experience a change of control, bondholders may require us to repurchase all or a portion of all of our senior subordinated notes at 101% of the principal amount plus accrued and unpaid interest, if any. All of the senior subordinated notes and the guarantees by our subsidiary guarantors are general, unsecured obligations and are subordinated to our bank debt and will be subordinated to future senior debt that we or our subsidiary guarantors are permitted to incur under the bank credit facility and the indentures governing the subordinated notes.

Early Extinguishment of Debt

On April 2, 2013, we announced a call for the redemption of $250.0 million of our outstanding 7.25% senior subordinated notes due 2018 at 103.625% of par which were redeemed on May 2, 2013. In second quarter 2013, we recognized a $12.3 million loss on extinguishment of debt, including transaction call premium costs as well as expensing of the remaining deferred financing costs on the repurchased debt.

In 2012, we called our 7.5% senior subordinated notes due 2017 at 103.75% of par which we redeemed on December 28, 2012. In fourth quarter 2012, we recognized an $11.1 million loss on extinguishment of debt, including transaction call premium costs as well as expensing of the remaining deferred financing cost on repurchased debt.

In May 2011, we commenced cash tender offers to purchase the entire outstanding $150.0 million principal amount of our 6.375% senior subordinated notes due 2015 and $250.0 million principal amount of our 7.5% senior subordinated notes due 2016. On May 25, 2011, after the expiration of the tender offers, we accepted for purchase $108.9 million in principal of the 2015 notes at 102.375% of par and $198.8 million in principal of the 2016 notes for 104.00% of par. We subsequently called the remaining 2015 and 2016 notes, redeeming all of the remaining outstanding 2015 notes ($41.1 million) at 102.125% of par on June 24, 2011 and redeeming all of the remaining 2016 notes ($51.2 million) at 103.75% of par on June 24, 2011. During 2011, we recognized an $18.6 million loss on extinguishment of debt, including transaction call premium cost as well as expensing of the remaining deferred financing costs on repurchased debt.

Guarantees

Range Resources Corporation is a holding company which owns no operating assets and has no significant operations independent of its subsidiaries. The guarantees by our subsidiaries of our senior subordinated notes are full and unconditional and joint and several, subject to certain customary release provisions. A subsidiary guarantor may be released from its obligations under the guarantee:

- in the event of a sale or other disposition of all or substantially all of the assets of the subsidiary guarantor or a sale or other disposition of all the capital stock of the subsidiary guarantor, to any corporation or other person (including an unrestricted subsidiary of Range) by way of merger, consolidation, or otherwise; or

- if Range designates any restricted subsidiary that is a guarantor to be an unrestricted subsidiary in accordance with the terms of the indenture.

Debt Covenants and Maturity

Our bank credit facility contains negative covenants that limit our ability, among other things, to pay cash dividends, incur additional indebtedness, sell assets, enter into certain hedging contracts, change the nature of our business or operations, merge, consolidate, or make investments. In addition, we are required to maintain a ratio of debt to EBITDAX (as defined in the credit agreement) of no greater than 4.25 to 1.0 and a ratio of current assets, including availability under the bank credit facility, to current liabilities of no less than 1.0 to 1.0 (as defined in the credit agreement). We were in compliance with our covenants under the bank credit facility at December 31, 2013.

The indentures governing our senior subordinated notes contain various restrictive covenants that are substantially identical to each other and may limit our ability to, among other things, pay cash dividends, incur additional indebtedness, sell assets, enter into transactions with affiliates, or change the nature of our business. At December 31, 2013, we were in compliance with these covenants.

The following is the principal maturity schedule for our long-term debt outstanding as of December 31, 2013 (in thousands):

	Year Ended December 31,
2014	$ —
2015	—
2016	500,000
2017	—
2018	—
Thereafter	2,640,516
	$ 3,140,516

(9) ASSET RETIREMENT OBLIGATIONS

Our asset retirement obligations primarily represent the estimated present value of the amounts we will incur to plug, abandon and remediate our producing properties at the end of their productive lives. Significant inputs used in determining such obligations include estimates of plugging and abandonment costs, estimated future inflation rates and well life. The inputs are calculated based on historical data as well as current estimated costs.

A reconciliation of our liability for plugging and abandonment costs for the years ended December 31, 2013 and 2012 is as follows (in thousands):

	2013	2012
Beginning of period	$ 146,478	$ 84,810
Liabilities incurred	8,731	9,802
Liabilities settled	(424)	(3,649)
Disposition of wells	(3,129)	(1,457)
Accretion expense	10,778	8,793
Change in estimate	67,643	48,179
End of period	230,077	146,478
Less current portion	(5,037)	(2,470)
Long-term asset retirement obligations	$ 225,040	$ 144,008

Accretion expense is recognized as an increase to depreciation, depletion and amortization expense in the accompanying statements of operations.

(10) CAPITAL STOCK

We have authorized capital stock of 485.0 million shares, which includes 475.0 million shares of common stock and 10.0 million shares of preferred stock. The following is a schedule of changes in the number of common shares outstanding since the beginning of 2011:

	Year Ended December 31,		
	2013	2012	2011
Beginning balance	162,514,098	161,131,547	159,909,052
Stock options/SARs exercised	278,916	926,425	862,774
Restricted stock grants	401,122	354,674	326,591
Restricted stock units vested	119,480	57,824	—
Treasury shares	29,278	43,628	33,130
Ending balance	163,342,894	162,514,098	161,131,547

Common Stock Dividends

The board of directors declared quarterly dividends of $0.04 per common share for each of the four quarters of 2013, 2012 and 2011. The determination of the amount of future dividends, if any, to be declared and paid is at the sole discretion of the board of directors and will depend on our financial condition, earnings and cash flow from operations, level of capital expenditures, our future business prospects and other matters our board of directors deem relevant. Our bank credit facility and our senior subordinated notes allow for the payment of common dividends, with certain limitations. Dividends are limited to our legally available funds.

(11) DERIVATIVE ACTIVITIES

We use commodity-based derivative contracts to manage exposure to commodity price fluctuations. We do not enter into these arrangements for speculative or trading purposes. We do not utilize complex derivatives as we typically utilize commodity swap or collar contracts to (1) reduce the effect of price volatility of the commodities we produce and sell and (2) support our annual capital budget and expenditure plans. Their fair value, represented by the estimated amount that would be realized upon termination, based on a comparison of the contract price and a reference price, generally NYMEX, approximated a net unrealized pre-tax loss of $16.5 million at December 31, 2013. These contracts expire monthly through December 2016. The following table sets forth the derivative volumes by year as of December 31, 2013:

Period	Contract Type	Volume Hedged	Weighted Average Hedge Price
Natural Gas			
2014	Collars	447,500 Mmbtu/day	$3.84–$4.48
2015	Collars	145,000 Mmbtu/day	$4.07–$4.56
2014	Swaps	219,397 Mmbtu/day	$4.17
2015	Swaps	154,966 Mmbtu/day	$4.16
2016	Swaps	20,000 Mmbtu/day	$4.16
Crude Oil			
2014	Collars	2,000 bbls/day	$85.55–$100.00
2014	Swaps	9,004 bbls/day	$94.43
2015	Swaps	4,000 bbls/day	$89.60
NGLs (C3 - Propane)			
2014	Swaps	11,000 bbls/day	$1.01/gallon
NGLs (NC4 - Normal Butane)			
2014	Swaps	3,000 bbls/day	$1.33/gallon
NGLs (C5 - Natural Gasoline)			
2014	Swaps	1,000 bbls/day	$2.11/gallon

Every derivative instrument is required to be recorded on the balance sheet as either an asset or a liability measured at its fair value. Through February 28, 2013, changes in the fair value of our derivatives that qualified for hedge accounting were recorded as a component of AOCI in the stockholders' equity section of the accompanying consolidated balance sheets, which were later transferred to natural gas, NGLs and oil sales when the underlying physical transaction occurred and the hedging contract was settled. As of December 31, 2013, an unrealized pre-tax derivative gain of $10.2 million was recorded in AOCI. See additional discussion below regarding the discontinuance of hedge accounting. If the derivative does not qualify as a hedge or is not designated as a hedge, changes in fair value of these non-hedge derivatives are recognized in earnings in derivative fair value income or loss.

For those derivative instruments that qualified for hedge accounting, settled transaction gains and losses were determined monthly, and were included as increases or decreases to natural gas, NGLs and oil sales in the period the hedged production was sold. Through February 28, 2013, we had elected to designate our commodity instruments that qualified for hedge accounting as cash flow hedges. Natural gas, NGLs and oil sales include $116.5 million of gains in 2013 compared to $236.3 million in 2012 and $123.6 million in 2011 related to settled hedging transactions. Any ineffectiveness associated with these hedge derivatives are reflected in derivative fair value income or loss in the accompanying statements of operations. The ineffective portion is calculated as the difference between the changes in fair value of the derivative and the estimated change in future cash flows from the item hedged. Derivative fair value for the year ended December 31, 2013 includes ineffective losses of $2.9 million compared to gains of $1.1 million in 2012 and gains of $9.5 million in 2011.

Discontinuance of Hedge Accounting

Effective March 1, 2013, we elected to de-designate all commodity contracts that were previously designated as cash flow hedges and elected to discontinue hedge accounting prospectively. AOCI included $103.6 million ($63.2 million after tax) as of February 28, 2013. As a result of discontinuing hedge accounting, the marked-to-market values included in AOCI as of the de-designation date were frozen and are being reclassified into earnings in natural gas, NGLs and oil sales in future periods as the underlying hedged transactions occur. As of December 31, 2013, we expect to reclassify into earnings $10.2 million of unrealized net gains in 2014 from AOCI.

With the election to de-designate hedging instruments, all of our derivative instruments continue to be recorded at fair value with all changes in fair value recognized immediately in earnings rather than in AOCI. These marked-to-market adjustments will produce a degree of earnings volatility that can be significant from period to period, but such adjustments will have no cash flow impact relative to changes in market prices. The impact to cash flow occurs upon settlement of the underlying contract.

Basis Swap Contracts

At December 31, 2013, we had natural gas basis swap contracts that are not designated for hedge accounting, which lock in the differential between NYMEX and certain of our physical pricing points in Appalachia. These contracts are for 320,280 Mmbtu/day and settle monthly through October 2014. The fair value of these contracts was a gain of $3.9 million on December 31, 2013.

Derivative assets and liabilities

The combined fair value of derivatives included in the accompanying consolidated balance sheets as of December 31, 2013 and 2012 is summarized below. As of December 31, 2013, we are conducting derivative activities with thirteen financial institutions, of which all but two are secured lenders in our bank credit facility. We believe all of these institutions are acceptable credit risks. At times, such risks may be concentrated with certain counterparties. The credit worthiness of our counterparties is subject to periodic review. The assets and liabilities are netted where derivatives with both gain and loss positions are held by a single counterparty and we have master netting arrangements (in thousands).

		December 31, 2013		
		Gross Amounts of Recognized Assets	Gross Amounts Offset in the Balance Sheet	Net Amounts of Assets Presented in the Balance Sheet
Derivative assets:				
Natural gas	–swaps	$ 4,240	$ (1,218)	$ 3,022
	–collars	16,057	(7,671)	8,386
	–basis swaps	7,686	(7,686)	—
Crude oil	–swaps	3,567	(1,321)	2,246
NGLs	–C3 swaps	826	(826)	—
	–C4 swaps	863	(863)	—
	–C5 swaps	121	(121)	—
		$ 33,360	$ (19,706)	$ 13,654

		December 31, 2013		
		Gross Amounts of Recognized (Liabilities)	Gross Amounts Offset in the Balance Sheet	Net Amounts of (Liabilities) Presented in the Balance Sheet
Derivative (liabilities):				
Natural gas	–swaps	$ (4,790)	$ 1,218	$ (3,572)
	–collars	(13,345)	7,671	(5,674)
	–basis swaps	(3,756)	7,686	3,930
Crude oil	–swaps	(4,711)	1,321	(3,390)
	–collars	(398)	—	(398)
NGLs	–C3 swaps	(18,172)	826	(17,346)
	–C4 swaps	(757)	863	106
	–C5 swaps	—	121	121
		$ (45,929)	$ 19,706	$ (26,223)

		December 31, 2012		
		Gross Amounts of Recognized Assets	Gross Amounts Offset in the Balance Sheet	Net Amounts of Assets Presented in the Balance Sheet
Derivative assets:				
Natural gas	–swaps	$ 10,746	$ (3,242)	$ 7,504
	–collars	128,410	(6,155)	122,255
	–basis swaps	993	—	993
Crude oil	–swaps	9,650	—	9,650
	–collars	2,222	—	2,222
NGLs	–C5 swaps	13,055	(2,412)	10,643
		$ 165,076	$ (11,809)	$ 153,267

		December 31, 2012		
		Gross Amounts of Recognized (Liabilities)	Gross Amounts Offset in the Balance Sheet	Net Amounts of (Liabilities) Presented in the Balance Sheet
Derivative (liabilities):				
Natural gas	–swaps	$ (3,242)	$ 3,242	$ —
	–collars	(9,618)	6,155	(3,463)
NGLs	–C3 swaps	(6,746)	—	(6,746)
	–C5 swaps	(137)	2,412	2,275
		$ (19,743)	$ 11,809	$ (7,934)

The effects of our cash flow hedges (or those derivatives that qualified for hedge accounting) on AOCI in the accompanying consolidated balance sheets is summarized below:

	Year Ended December 31,			
	Change in Hedge Derivative Fair Value		Realized Gain Reclassified from OCI Into Revenue [(a)]	
	2013	2012	2013	2012
Swaps	$ 125	$ 46,371	$ 15,171	$ 78,779
Put options	—	(1,955)	—	(1,955)
Collars	(7,015)	74,766	105,272	159,481
Income taxes	2,687	(47,466)	(46,973)	(91,871)
	$ (4,203)	$ 71,716	$ 73,470	$ 144,434

(a) For realized gains upon contract settlement, the reduction in AOCI is offset by an increase in natural gas, NGLs and oil sales. For realized losses upon contract settlement, the increase in AOCI is offset by a decrease in natural gas, NGLs and oil sales.

The effects of our non-hedge derivatives (or those derivatives that do not qualify or are not designated for hedge accounting) and the ineffective portion of our hedge derivatives on our consolidated statements of operations are summarized below:

	Year Ended December 31,								
	Gain (Loss) Recognized in Income (Non-hedge Derivatives)			Gain (Loss) Recognized in Income (Ineffective Portion)			Derivative Fair Value (Loss) Income		
	2013	2012	2011	2013	2012	2011	2013	2012	2011
Swaps	$ (48,492)	$ 11,601	$ 24,767	$ (2,034)	$ (657)	$ 767	$ (50,526)	$ 10,944	$ 25,534
Re-purchased swaps	1,323	9,313	—	—	—	—	1,323	9,313	—
Collars	(15,166)	5,126	5,266	(896)	1,782	8,777	(16,062)	6,908	14,043
Call options	—	13,178	553	—	—	—	—	13,178	553
Put options	—	(30)	—	—	—	—	—	(30)	—
Basis swaps	3,440	1,124	(43)	—	—	—	3,440	1,124	(43)
Total	$ (58,895)	$ 40,312	$ 30,543	$ (2,930)	$ 1,125	$ 9,544	$ (61,825)	$ 41,437	$ 40,087

The United States adopted comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivative market and entities, such as Range, that participate in that market. The new regulation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act, required the Commodities Futures Trading Commission (the "CFTC") and the SEC to promulgate rules and regulations implementing the new legislation. In July 2012 certain definitions were adopted by the SEC and the CFTC and based on those definitions, we believe we will qualify for the end-user exception related to the clearing requirement for swaps but we will be required to adhere to new reporting requirements.

(12) FAIR VALUE MEASUREMENTS

Fair value is 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. There are three approaches for measuring the fair value of assets and liabilities: the market approach, the income approach and the cost approach, each of which includes multiple valuation techniques. The market approach uses prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities. The income approach uses valuation techniques to measure fair value by converting future amounts, such as cash flows or earnings, into a single present value amount using current market expectations about those future amounts. The cost approach is based on the amount that would currently be required to replace the service capacity of an asset. This is often referred to as current replacement cost. The cost approach assumes that the fair value would not exceed what it would cost a market participant to acquire or construct a substitute asset of comparable utility, adjusted for obsolescence.

The fair value accounting standards do not prescribe which valuation technique should be used when measuring fair value and do not prioritize among the techniques. These standards establish a fair value hierarchy that prioritizes the inputs used in applying the various valuation techniques. Inputs broadly refer to the assumptions that market participants use to make pricing decisions, including assumptions about risk. Level 1 inputs are given the highest priority in the fair value hierarchy, while Level 3 inputs are given the lowest priority. The three levels of the fair value hierarchy are as follows:

- Level 1 – Observable inputs that reflect unadjusted quoted prices for identical assets or liabilities in active markets 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 2 – Observable market-based inputs or unobservable inputs that are corroborated by market data. These are inputs other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date.
- Level 3 – Unobservable inputs that are not corroborated by market data and may be used with internally developed methodologies that result in management's best estimate of fair value.

Valuation techniques that maximize the use of observable inputs are favored. Assets and liabilities are classified in their entirety based on the lowest priority level of input that is significant to the fair value measurement. The assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement of assets and liabilities within the levels of the fair value hierarchy.

Fair Values-Recurring

We use a market approach for our recurring fair value measurements and endeavor to use the best information available. Accordingly, valuation techniques that maximize the use of observable impacts are favored. The following tables present the fair value hierarchy table for assets and liabilities measured at fair value, on a recurring basis (in thousands):

		Fair Value Measurements at December 31, 2013 Using:			
		Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Carrying Value as of December 31, 2013
Trading securities held in the deferred compensation plans		$ 67,766	$ —	$ —	$ 67,766
Derivatives	–swaps	—	(18,812)	—	(18,812)
	–collars	—	2,314	—	2,314
	–basis swaps	—	3,381	548	3,929

		Fair Value Measurements at December 31, 2012 Using:			
		Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Carrying Value as of December 31, 2012
Trading securities held in the deferred compensation plans		$ 57,776	$ —	$ —	$ 57,776
Derivatives	–swaps	—	23,326	—	23,326
	–collars	—	121,014	—	121,014
	–basis swaps	—	993	—	993

Our trading securities in Level 1 are exchange-traded and measured at fair value with a market approach using December 31, 2013 market values. Derivatives in Level 2 are measured at fair value with a market approach using third-party pricing services, which have been corroborated with data from active markets or broker quotes. As of December 31, 2013, we have four natural gas basis swaps categorized as Level 3 due to the forward price curve being unavailable for the regional sales point. We based the fair value on the most similar regional forward natural gas basis curve received from a third party pricing service along with assumed basis differentials based on historical trends.

The following is a reconciliation of the net beginning and ending balances for derivative instruments classified as Level 3 in the fair value hierarchy (in thousands):

	2013
Beginning balance	$ —
Unrealized gains included in derivative fair value	548
Ending balance	$ 548

Our trading securities held in the deferred compensation plan are accounted for using the mark-to-market accounting method and are included in other assets in the accompanying consolidated balance sheets. We elected to adopt the fair value option to simplify our accounting for the investments in our deferred compensation plan. Interest, dividends, and mark-to-market gains/losses are included in deferred compensation plan expense in the accompanying statements of operations. For the year ended December 31, 2013, interest and dividends were $1.2 million and mark-to-market was a gain of $3.9 million. For the year ended December 31, 2012, interest and dividends were $1.4 million and mark-to-market was a gain of $4.7 million. For the year ended December 31, 2011, interest and dividends were $1.4 million and the mark-to-market was a loss of $2.3 million.

Fair Values-Non recurring

Due to declines in commodity prices and estimated reserves over the last three years, there were indications that the carrying values of certain of our oil and gas properties may be impaired and undiscounted future cash flows attributed to these assets indicated their carrying amounts were not expected to be recovered. Their fair value was measured using an income approach based upon internal estimates of future production levels, prices, drilling and operating costs and discount rates, which are Level 3 inputs. In some cases, we also considered the potential sale of certain of these properties. We recorded non-cash charges during 2013 of $7.0 million related to Gulf Coast onshore oil and gas properties. We recorded non-cash charges during 2012 of $31.1 million related to our

Mississippi natural gas and oil properties and $3.2 million related to our remaining oil and natural gas properties in North Texas. We recorded non-cash charges during 2011 of $31.2 million related to our East Texas natural gas and oil properties and $7.5 million related to our Gulf Coast onshore properties. Also in 2013 and 2012, we evaluated certain surface property we own which included a consideration for the potential sale of the assets and we recognized an impairment charges of $741,000 in 2013 and $1.3 million in 2012.

The following table presents the value of these assets measured at fair value on a nonrecurring basis at the time impairment was recorded (in thousands):

	Year Ended December 31,					
	2013		2012		2011	
	Fair Value	Impairment	Fair Value	Impairment	Fair Value	Impairment
Natural gas and oil properties–continuing operations	$ 500	$ 7,012	$ 12,604	$ 34,273	$ 24,388	$ 38,681
Surface property	5,550	741	6,269	1,281	—	—

Fair Values - Reported

The following table presents the carrying amounts and the fair values of our financial instruments as of December 31, 2013 and 2012 (in thousands):

	December 31, 2013		December 31, 2012	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Assets:				
Commodity swaps, collars and basis swaps	$ 13,654	$ 13,654	$ 153,267	$ 153,267
Marketable securities[(a)]	67,766	67,766	57,776	57,776
Liabilities:				
Commodity swaps, collars and basis swaps	(26,223)	(26,223)	(7,934)	(7,934)
Bank credit facility[(b)]	(500,000)	(500,000)	(739,000)	(739,000)
Deferred compensation plan[(c)]	(271,738)	(271,738)	(201,889)	(201,889)
7.25% senior subordinated notes due 2018[(b)]	—	—	(250,000)	(262,500)
8.00% senior subordinated notes due 2019[(b)]	(290,516)	(319,500)	(289,185)	(332,250)
6.75% senior subordinated notes due 2020[(b)]	(500,000)	(541,250)	(500,000)	(542,500)
5.75% senior subordinated notes due 2021[(b)]	(500,000)	(530,625)	(500,000)	(535,000)
5.00% senior subordinated notes due 2022[(b)]	(600,000)	(588,750)	(600,000)	(627,000)
5.00% senior subordinated notes due 2023[(b)]	(750,000)	(732,188)	—	—

(a) Marketable securities are held in our deferred compensation plans that are actively traded on major exchanges.
(b) The book value of our bank debt approximates fair value because of its floating rate structure. The fair value of our senior subordinated notes is based on end of period market quotes, which are Level 2 inputs.
(c) The fair value of our deferred compensation plan is updated based on the closing price on the balance sheet date.

Our current assets and liabilities contain financial instruments, the most significant of which are trade accounts receivables and payables. We believe the carrying values of our current assets and liabilities approximate fair value. Our fair value assessment incorporates a variety of considerations, including (1) the short-term duration of the instruments and (2) our historical incurrence of and expected future insignificance of bad debt expense.

Concentrations of Credit Risk

As of December 31, 2013, our primary concentration of credit risk is the risk of collecting accounts receivable and the risk of counterparties' failure to perform under derivative obligations. See Note 2 for information regarding our accounts receivable and derivative assets and liabilities by counterparty and Note 16 for information regarding our major customers.

(13) STOCK-BASED COMPENSATION PLANS

Description of the Plans

The 2005 Equity Based Compensation Plan (the "2005 Plan") authorizes the compensation committee of the board of directors to grant, among other things, stock options, stock appreciation rights ("SARs") and restricted stock awards to employees and directors. The 2004 Non-Employee Director Stock Option Plan (the "Director Plan") allows such grants to our non-employee directors of our board of directors. The 2005 Plan was approved by stockholders in May 2005 and replaced our 1999 Stock Option Plan. No new grants have been made from the 1999 Stock Option Plan. The number of shares that may be issued under the 2005 Plan is equal to (i) 5.6 million shares (15.0 million less the 2.2 million shares issued under the 1999 Stock Option Plan before May 18, 2005, the effective date of the 2005 Plan and less the 7.2 million shares issuable pursuant to awards under the 1999 Stock Option Plan outstanding as of the effective date of the 2005 Plan) plus (ii) the number of shares subject to 1999 Stock Option Plan awards outstanding at May 18, 2005 that subsequently lapse or terminate without the underlying shares being issued plus (iii) subsequent shares approved by the shareholders. The Director Plan was approved by stockholders in May 2004 and no more than 450,000 shares of common stock may be issued under the Director Plan.

Stock-Based Awards

Stock options represent the right to purchase shares of stock in the future at the fair value of the stock on the date of grant. Most stock options granted under our stock option plans vest over a three-year period and expire five years from the date they were granted. Beginning in 2005, we began granting SARs to reduce the dilutive impact of our equity plans. Similar to stock options, SARs represent the right to receive a payment equal to the excess of the fair market value of shares of common stock on the date the right is exercised over the value of the stock on the date of grant. All SARs granted under the 2005 Plan will be settled in shares of stock, vest over a three-year period and have a maximum term of five years from the date they are granted. Beginning in first quarter 2011, the Compensation Committee also began granting restricted stock units under our equity-based stock compensation plans. These restricted stock units, which we refer to as restricted stock Equity Awards, vest over a three-year period. All awards granted have been issued at prevailing market prices at the time of grant and the vesting of these shares is based upon an employee's continued employment with us.

The compensation committee also grants restricted stock to certain employees and non-employee directors of the board of directors as part of their compensation. Compensation expense is recognized over the balance of the vesting period, which is typically three years for employee grants and immediate vesting for non-employee directors. All restricted stock awards are issued at prevailing market prices at the time of the grant and the vesting is based upon an employee's continued employment with us. Prior to vesting, all restricted stock awards have the right to vote such stock (by the trustee) and receive dividends thereon. Upon grant of these restricted shares, which we refer to as restricted stock Liability Awards, the shares are placed in our deferred compensation plan and, upon vesting, employees are allowed to take withdrawals either in cash or in stock. These Liability Awards are classified as a liability and are remeasured at fair value each reporting period. This mark-to-market amount is reported in deferred compensation plan expense in the accompanying consolidated statements of operations. Historically, we have used authorized but unissued shares of stock when restricted stock is granted. However, we also utilize treasury shares when available.

Total Stock-Based Compensation Expense

Stock-based compensation represents amortization of restricted stock, restricted stock units and SARs expense. The following table details the amount of stock-based compensation that is allocated to functional expense categories (in thousands):

	2013	2012	2011
Operating expense	$ 2,755	$ 2,415	$ 1,987
Brokered natural gas and marketing expense	1,852	1,765	1,455
Exploration expense	4,025	4,049	4,108
General and administrative expense	55,737	44,541	36,244
Total	$ 64,369	$ 52,770	$ 43,794

Unlike the other forms of stock-based compensation mentioned above, the mark-to-market of the liability related to the vested restricted stock held in our deferred compensation plans is directly tied to the change in our stock price and not directly related to the functional expenses and therefore, is not allocated to the functional categories. The increase in 2013 stock-based compensation is primarily due to additional expense of $10.0 million related to the acceleration of stock-based compensation for our executive chairman who became a non-employee director on January 1, 2014. For the year ended December 31, 2013, cash received upon exercise of stock options/SARs awards was $343,000. For the year ended December 31, 2013 and 2012, tax benefits realized for deductions that were in excess of the stock-based compensation expense were not recognized due to our net operating loss position. In

2011, as a result of realizing federal taxable income, a tax benefit of $11.7 million has been recognized in our net operating loss carryforward for the excess tax deduction over our stock-based compensation expense.

Stock Options and Stock Appreciation Right Awards

We have two active equity-based stock plans, the 2005 Plan and the Director Plan. Under these plans, incentive and non-qualified stock options, stock appreciation rights, restricted stock units and various other awards may be issued to directors and employees pursuant to decisions of the compensation committee, which is made up of non-employee, independent directors from the board of directors. All awards granted under these plans have been issued at prevailing market prices at the time of the grant. Of the 2.6 million grants outstanding at December 31, 2013, all grants relate to SARs. Information with respect to stock option and SARs activities is summarized below.

	Shares	Weighted Average Exercise Price
Outstanding at December 31, 2010	6,461,839	$ 37.20
Granted	843,485	51.17
Exercised	(2,511,989)	32.69
Expired/forfeited	(234,726)	52.65
Outstanding at December 31, 2011	4,558,609	41.47
Granted	754,471	64.14
Exercised	(1,860,367)	30.20
Expired/forfeited	(19,351)	48.00
Outstanding at December 31, 2012	3,433,362	52.52
Granted	470,617	75.82
Exercised	(1,269,323)	53.24
Expired/forfeited	(52,582)	53.56
Outstanding at December 31, 2013	2,582,074	$ 56.36

The following table shows information with respect to stock options and SARs outstanding and exercisable at December 31, 2013:

	Outstanding			Exercisable	
Range of Exercise Prices	Shares	Weighted Average Remaining Contractual Life (in years)	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
$ 31.13–$ 39.99	44,980	0.24	$ 34.48	44,980	$ 34.48
40.00–49.99	1,007,979	1.10	44.82	917,558	44.39
50.00–59.99	404,799	2.38	52.35	227,838	52.35
60.00–69.99	657,040	3.34	64.17	208,043	64.22
70.00–79.99	466,480	4.33	75.85	22,141	77.26
80.00–80.34	796	4.25	80.34	796	80.34
Total	2,582,074	2.44	$ 56.36	1,421,356	$ 48.79

During 2013, 2012 and 2011, we granted SARs to officers, non-officer employees and directors. The weighted average grant date fair value of these SARs, based on our Black-Scholes-Merton assumptions, is shown below:

	2013	2012	2011
Weighted average exercise price per share	$ 75.82	$ 64.14	$ 51.17
Expected annual dividends per share	0.21%	0.25%	0.31%
Expected life in years	3.7	3.7	3.7
Expected volatility	35%	45%	47%
Risk-free interest rate	0.6%	0.5%	1.4%
Weighted average grant date fair value	$ 20.20	$ 21.32	$ 18.22

The expected dividend yield is based on the current annual dividend at the time of grant. The expected life was based on the historical exercise activity. The expected volatility factors are based on a combination of both the historical volatilities of the stock and implied volatility of traded options on our common stock. The risk-free interest rate is based on the U.S. Treasury yield curve in effect at the time of grant for periods commensurate with the expected terms of the options.

The total intrinsic value (the difference in value between exercise and market price) of stock options and SARs exercised during the years ended December 31, 2013 was $30.3 million compared to $61.0 million in 2012 and $62.5 million in 2011. As of December 31, 2013, the aggregate intrinsic value of the awards outstanding was $72.2 million. The aggregate intrinsic value and weighted average remaining contractual life of stock option/SARs awards exercisable as of December 31, 2013 was $50.5 million and 1.6 years. As of December 31, 2013, the number of fully vested awards and awards expected to vest was 2.5 million shares. The weighted average exercise price and weighted average remaining contractual life of these awards were $56.12 and 2.4 years and the aggregate intrinsic value was $71.5 million. As of December 31, 2013, unrecognized compensation cost related to the awards was $10.3 million, which is expected to be recognized over a weighted average period of 1.7 years.

Restricted Stock Awards

Equity Awards

In 2013, we granted 402,000 restricted stock Equity Awards to employees which generally vest over a three-year period. We recorded compensation expense for these awards of $19.7 million in the year ended December 31, 2013. In 2012, we granted 364,000 restricted stock Equity Awards to employees which generally vest over a three-year period. We recorded compensation expense for these awards of $11.8 million in the year ended December 31, 2012. In 2011, we granted 331,000 restricted stock Equity Awards to employees and recorded compensation expense of $4.2 million. As of December 31, 2013, there was $24.8 million of unrecognized compensation related to Equity Awards expected to be recognized over a weighted average period of 1.8 years. Equity Awards are not issued to employees until such time they are vested and the employees do not have the option to receive cash.

Liability Awards

In 2013, we granted 425,000 shares of restricted stock Liability Awards as compensation to directors and employees at an average price of $75.53. This grant included 18,000 issued to non-employee directors, which vest immediately, and 407,000 to employees with vesting generally over a three-year period. In 2012, we granted 381,000 shares of restricted stock Liability Awards as compensation to directors and employees at an average price of $64.06. This grant included 14,700 issued to non-employee directors, which vest immediately, and 366,300 to employees with vesting generally over a three-year period. In 2011, we granted 352,000 shares of Liability Awards as compensation to directors and employees at an average price of $51.17. This grant included 18,000 issued to non-employee directors, which vest immediately, and 334,000 to employees with vesting generally over a three-year period. We recorded compensation expense for these Liability Awards of $27.4 million in the year ended December 31, 2013 compared to $21.5 million in 2012 and $19.1 million in 2011. As of December 31, 2013, there was $24.8 million of unrecognized compensation related to Liability Awards expected to be recognized over a weighted average period of 1.9 years. Substantially all of these awards are held in our deferred compensation plan, are classified as a liability and are remeasured at fair value each reporting period. This mark-to-market is reported as deferred compensation expense in our consolidated statements of operations (see additional discussion below). The proceeds received from the sale of stock held in our deferred compensation plan was $20.7 million in 2013.

A summary of the status of our non-vested restricted stock outstanding at December 31, 2013 is summarized below:

	Equity Awards		Liability Awards	
	Shares	Weighted Average Grant Date Fair Value	Shares	Weighted Average Grant Date Fair Value
Outstanding at December 31, 2010	—	$ —	582,751	$ 44.81
Granted	331,209	49.56	352,419	51.17
Vested	(88,854)	49.37	(418,634)	45.55
Forfeited	(20,746)	49.45	(29,292)	45.04
Outstanding at December 31, 2011	221,609	49.64	487,244	48.76
Granted	364,082	63.44	380,808	64.06
Vested	(208,802)	56.73	(438,283)	52.17
Forfeited	(27,733)	58.65	(6,291)	54.54
Outstanding at December 31, 2012	349,156	59.08	423,478	58.91
Granted	402,053	71.26	424,809	75.53
Vested	(315,535)	62.43	(437,570)	64.36
Forfeited	(50,611)	65.29	(21,704)	57.31
Outstanding at December 31, 2013	385,063	$ 68.24	389,013	$ 71.02

401(k) Plan

We maintain a 401(k) benefit plan that allows employees to contribute up to 75% of their salary (subject to Internal Revenue Service limitations) on a pretax basis. Beginning in 2008, we began matching up to 6% of salary in cash. All our contributions become fully vested after the individual employee has two years of service with us. Beginning in 2013, vesting of our contributions was immediate. In 2013, we contributed $5.1 million to the 401(k) Plan compared to $4.0 million in 2012. Employees have a variety of investment options in the 401(k) benefit plan.

Deferred Compensation Plan

Our deferred compensation plan gives directors, officers and key employees the ability to defer all or a portion of their salaries and bonuses and invest in Range common stock or make other investments at the individual's discretion. Range provides a partial matching contribution which vests over three years. The assets of the plans are held in a grantor trust, which we refer to as the Rabbi Trust, and are therefore available to satisfy the claims of our creditors in the event of bankruptcy or insolvency. Our stock held in the Rabbi Trust is treated as a liability award as employees are allowed to take withdrawals from the Rabbi Trust either in cash or in Range stock. The liability for the vested portion of the stock held in the Rabbi Trust is reflected in the deferred compensation liability in the accompanying consolidated balance sheets and is adjusted to fair value each reporting period by a charge or credit to deferred compensation plan expense on our consolidated statements of operations. The assets of the Rabbi Trust, other than our common stock, are invested in marketable securities and reported at their market value in other assets in the accompanying consolidated balance sheets. The deferred compensation liability reflects the vested market value of the marketable securities and Range stock held in the Rabbi Trust. Changes in the market value of the marketable securities and changes in the fair value of the deferred compensation plan liability are charged or credited to deferred compensation plan expense each quarter. We recorded a mark-to-market loss of $55.3 million in 2013 compared to $7.2 million loss in 2012 and $43.2 million loss in 2011. The Rabbi Trust held 2.8 million shares (2.4 million of vested shares) of Range stock at December 31, 2013 compared to 2.7 million shares (2.3 million of vested shares) at December 31, 2012.

(14) SUPPLEMENTAL CASH FLOW INFORMATION

	Year Ended December 31,		
	2013	2012	2011
		(in thousands)	
Net cash provided from operating activities included:			
Income taxes (refunded from) paid to taxing authorities	$ (347)	$ 386	$ 675
Interest paid	159,137	153,249	133,103
Non-cash investing and financing activities included:			
Asset retirement costs capitalized, net	$ 76,373	$ 57,982	$ 24,061
Increase (decrease) in accrued capital expenditures	27,079	(94,121)	86,561

(15) COMMITMENTS AND CONTINGENCIES

Litigation

James A. Drummond and Chris Parrish v. Range Resources-Midcontinent, LLC et al.; pending at the District Court of Grady County, State of Oklahoma; Case No. CJ-2010-510

As we previously disclosed, the parties successfully mediated the case in May 2013 resulting in a settlement and we executed a Stipulation and Agreement of Settlement, with an effective date of May 31, 2013, providing for a cash payment to the class in the amount of $87.5 million in settlement of all claims made by the class for the period prior to May 31, 2013. Pursuant to the settlement agreement, on June 28, 2013, we paid $87.5 million into an escrow amount. On September 9, 2013, the Court approved the settlement thereby finally concluding this matter.

We are the subject of, or party to, a number of pending or threatened legal actions and claims arising in the ordinary course of our business. While many of these matters involve inherent uncertainty, we believe that the amount of the liability, if any, ultimately incurred with respect to proceedings or claims will not have a material adverse effect on our consolidated financial position as a whole or on our liquidity, capital resources or future annual results of operations. We will continue to evaluate our litigation on a quarter-by-quarter basis and will establish and adjust any litigation reserves as appropriate to reflect our assessment of the then current status of litigation.

Lease Commitments

We lease certain office space, office equipment, production facilities, compressors and transportation equipment under cancelable and non-cancelable leases. Rent expense under operating leases (including renewable monthly leases and amounts related to discontinued operations) totaled $13.1 million in 2013 compared to $13.8 million in 2012 and $18.6 million in 2011. Commitments related to these lease payments are not recorded in the accompanying consolidated balance sheets. Future minimum rental commitments under non-cancelable leases having remaining lease terms in excess of one year are as follows (in thousands):

	Operating Lease Obligations
2014	$ 19,946
2015	19,170
2016	12,434
2017	6,879
2018	5,576
Thereafter	17,230
	$ 81,235

Transportation and Gathering Contracts

We have entered into firm transportation and gathering contracts with various pipeline carriers for the future transportation and gathering of natural gas, NGLs and oil production primarily from our properties in Pennsylvania. Under these contracts, we are obligated to transport or gather minimum daily natural gas volumes, or pay for any deficiencies at a specified reservation fee rate. In most cases, our production committed to these pipelines is expected to exceed the minimum daily volumes provided in the contracts. As of December 31, 2013, future minimum transportation and gathering fees under our commitments are as follows (in thousands):

	Transportation and Gathering Contracts
2014	$ 227,061
2015	238,148
2016	261,854
2017	258,227
2018	228,321
Thereafter	1,363,537
	$ 2,577,148

In addition to the amounts included in the above table, we have contracted with several pipeline companies through 2030 to transport natural gas, ethane and propane production volumes from certain Marcellus Shale wells. These agreements and related fees, which are contingent on certain pipeline modifications and/or pipeline construction, are commitments that range between three and fifteen year terms and are expected to begin in late 2014 through late 2017. Based on these contracts, we will be obligated for a range of natural gas volumes from 40,000 mcfe per day to 200,000 mcfe per day and ethane and propane volumes from 10,000 to 20,000 bbls per day through the end of the contract terms.

Drilling Contracts

As of December 31, 2013, we have contracts with drilling contractors to use three drilling rigs with terms of up to two years and minimum future commitments of $9.0 million in 2014 and $6.7 million in 2015. Early termination of these contracts at December 31, 2013 would have required us to pay maximum penalties of $10.9 million. We do not expect to pay any early termination penalties related to these contracts.

Delivery Commitments

We have various volume delivery commitments that are primarily related to our Midcontinent and Marcellus Shale areas. We expect to be able to fulfill our contractual obligations from our own production, however; we may purchase third party volumes to satisfy our commitments or pay demand fees for commitment shortfalls, should they occur. As of December 31, 2013, our delivery commitments through 2028 were as follows:

Year Ending December 31,	Natural Gas (mcf per day)	Ethane (bbls per day)
2014	145,500	15,000
2015	140,538	15,000
2016	102,598	15,000
2017	52,055	15,000
2018—2028	—	15,000

In addition to the amounts included in the above table, we have contracted with several pipeline companies through 2030 to deliver ethane production volumes in Appalachia from our Marcellus Shale wells. These agreements and related fees, which are contingent upon pipeline construction and/or modification, are for 10,000 bbls per day and starting in 2015, increases to 20,000 bbls per day until the end of the contractual terms.

Other

We have agreements in place for hydraulic fracturing including related equipment, material and labor for $24.0 million in 2014 and $12.0 million in 2015. We also have agreements to purchase seismic data for $10.6 million in 2014 and $838,000 in 2015. We also have lease acreage that is generally subject to lease expiration if initial wells are not drilled within a specified period, generally between three to five years. We do not expect to lose significant lease acreage because of failure to drill due to inadequate capital, equipment or personnel. However, based on our evaluation of prospective economics, we have allowed acreage to expire and will allow additional acreage to expire in the future. To date, our expenditures to comply with environmental or safety regulations have not been a significant component of our cost structure and are not expected to be significant in the future. However, new regulations, enforcement policies, claims for damages or other events could result in significant future costs.

(16) MAJOR CUSTOMERS

We sell our share of our production to various purchasers. We record allowance for doubtful accounts based on the age of the accounts receivable the financial condition of the purchasers, and we may require purchasers to provide collateral or otherwise secure their account. For the year ended December 31, 2013, we had four customers that accounted for 10% or more of total natural gas, NGLs and oil sales. For the years ended December 31, 2012 and 2011, we had two customers that accounted for 10% or more of total natural gas, NGLs and oil sales. We believe that the loss of any one customer would not have an adverse effect on our ability to sell our natural gas, NGLs and oil production.

(17) EQUITY METHOD INVESTMENTS

We account for our investments in entities over which we have significant influence, but not control, using the equity method of accounting. Under the equity method of accounting, we record our proportionate share of net earnings, declared dividends and partnership distributions based on the most recently available financial statements of the investee. We also evaluate our equity method investments for potential impairment whenever events or changes in circumstances indicate that there is an other than temporary decline in value of the investment. Such events may include sustained operating losses by the investee or long-term negative changes in the investee's industry.

Investment in Whipstock Natural Gas Services, LLC

In 2006, we acquired a 50% interest in Whipstock Natural Gas Services, LLC ("Whipstock"), an unconsolidated investee in the business of providing oil and gas drilling equipment, well servicing rigs and equipment, and other well services in Appalachia. On the acquisition date, we contributed cash of $11.7 million representing the fair value of 50% of the membership interest in Whipstock. In September 2013, we sold our equity method investment in Whipstock for proceeds of $7.0 million and recognized a gain of $4.4 million.

Whipstock follows a calendar year basis of financial reporting consistent with us and our equity in Whipstock's earnings from the acquisition date is included in brokered natural gas, marketing and other revenue in the accompanying statements of operations for 2013, 2012 and 2011. In determining our proportionate share of the net earnings of Whipstock, certain adjustments are required to be made to Whipstock's reported results to eliminate the profits recognized by Whipstock for services provided to us. For the year ended December 31, 2013, our equity in the income of Whipstock totaled $608,000 compared to income of $818,000 in 2012 and losses of $481,000 in 2011. In 2012, equity in the losses of Whipstock was reduced by $14,000 to eliminate the profit on services provided to us compared to $6,000 in 2011.

Investment in Nora Gathering, LLC

In May 2007, we completed the initial closing of a joint development arrangement with EQT Corporation ("EQT"). Pursuant to the terms of the arrangement, Range and EQT ("the parties") agreed to, among other things, form a new pipeline and natural gas gathering operations entity, Nora Gathering, LLC ("NGLLC"). NGLLC is an unconsolidated investee created by the parties for the purpose of conducting pipeline, natural gas gathering, and transportation operations associated with the parties' collective interests in properties in the Nora Field. In connection with the acquisition, we contributed cash of $94.7 million for a 50% membership interest in NGLLC. In 2013, 2012 or 2011, Range and EQT made no additional contributions to fund the expansion of the Nora Field gathering system infrastructure.

NGLLC follows a calendar year basis of financial reporting consistent with us and our equity in NGLLC earnings from the acquisition date is included in brokered natural gas, marketing and other revenue in the accompanying statements of operations for 2013, 2012 and 2011. In 2011, we received partnership distributions of $23.5 million, compared to $12.8 million in 2012 and $9.0 million in 2013. In determining our proportionate share of the net earnings of NGLLC, certain adjustments are required to be made to NGLLC's reported results to eliminate the profits recognized by NGLLC included in the gathering and transportation fees charged to us on production in the Nora Field. For the year ended December 31, 2013, our equity in losses of NGLLC of $146,000 reflects a reduction of $7.7 million to eliminate the profit on the gathering and transportation fees charged to us. For the year ended December 31, 2012, our equity in the losses of NGLLC of $1.2 million reflects a reduction of $7.5 million to eliminate the profit on the gathering and transportation fees charged to us. For the year ended December 31, 2011, our equity in the losses of NGLLC of $563,000 reflects a reduction of $7.7 million to eliminate the profit on gathering and transportation fees charged to us. Our net book value in this equity investment was $129.0 million at December 31, 2013.

(18) SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

The following tables set forth unaudited financial information on a quarterly basis for each of the last two years. General and administrative expense in the first quarter 2013 includes a $35.0 million Drummond lawsuit settlement accrual. Second quarter 2013 includes an additional $52.5 million related to the Drummond legal settlement. Second quarter 2013 also includes a gain of $79.4 million from the sale of our Delaware and Permian Basin properties in southeast New Mexico and West Texas. The fourth quarter 2013 deferred tax expense includes a $21.2 million benefit for state apportionment rate adjustments.

	2013				
	March	June	September	December	Total
Revenues and other income:					
Natural gas, NGLs and oil sales	$ 398,239	$ 437,678	$ 431,214	$ 448,545	$ 1,715,676
Derivative fair value (loss) income	(99,875)	137,760	(40,355)	(59,355)	(61,825)
(Loss) gain on the sale of assets	(166)	83,287	6,008	3,162	92,291
Brokered natural gas, marketing and other	21,041	14,631	45,171	35,734	116,577
Total revenue and other income	319,239	673,356	442,038	428,086	1,862,719
Costs and expenses:					
Direct operating	30,188	32,636	30,907	34,360	128,091
Transportation, gathering and compression	62,416	66,048	60,958	66,820	256,242
Production and ad valorem taxes	11,383	11,113	11,454	11,290	45,240
Brokered natural gas and marketing	22,315	16,662	51,117	41,692	131,786
Exploration	16,780	13,068	20,496	14,065	64,409
Abandonment and impairment of unproved properties	15,218	19,156	11,692	5,852	51,918
General and administrative	84,058	101,987	44,919	60,207	291,171
Deferred compensation plan	42,360	(6,878)	(2,225)	22,039	55,296
Interest expense	42,210	45,071	44,321	44,955	176,557
Loss on early extinguishment of debt	—	12,280	—	—	12,280
Depletion, depreciation and amortization	115,101	119,995	130,343	126,958	492,397
Impairment of proved properties and other	—	741	7,012	—	7,753
Total costs and expenses	442,029	431,879	410,994	428,238	1,713,140
(Loss) income from continuing operations before income taxes	(122,790)	241,477	31,044	(152)	149,579
Income tax (benefit) expense	25	(25)	—	(143)	(143)
Current	(47,205)	97,519	11,866	(28,180)	34,000
Deferred	(47,180)	97,494	11,866	(28,323)	33,857
Net (loss) income	$ (75,610)	$ 143,983	$ 19,178	$ 28,171	$ 115,722
Net (loss) income per common share:					
Basic	$ (0.47)	$ 0.88	$ 0.12	$ 0.17	$ 0.71
Diluted	$ (0.47)	$ 0.88	$ 0.12	$ 0.17	$ 0.70

	2012				
	March	June	September	December	Total
Revenues and other income:					
Natural gas, NGLs and oil sales	$ 317,617	$ 298,349	$ 337,040	$ 398,688	$ 1,351,694
Derivative fair value (loss) income	(60,833)	148,569	(40,728)	(5,571)	41,437
(Loss) gain on the sale of assets	(10,426)	(3,227)	949	61,836	49,132
Brokered natural gas, marketing and other	4,597	5,240	2,519	3,085	15,441
Total revenue and other income	250,955	448,931	299,780	458,038	1,457,704
Costs and expenses:					
Direct operating	29,022	27,041	29,628	30,214	115,905
Transportation, gathering and compression	40,820	44,744	51,600	55,281	192,445
Production and ad valorem taxes	36,634	11,786	8,819	9,881	67,120
Brokered natural gas and marketing	4,062	6,491	4,887	4,994	20,434
Exploration	21,516	15,517	14,752	18,022	69,807
Abandonment and impairment of unproved properties	20,289	43,641	40,118	21,230	125,278
General and administrative	38,729	44,005	44,497	46,582	173,813
Deferred compensation plan	(7,830)	9,333	20,052	(14,352)	7,203
Interest expense	37,205	42,888	43,997	44,708	168,798
Loss on early extinguishment of debt	—	—	—	11,063	11,063
Depletion, depreciation and amortization	100,151	108,802	123,059	113,216	445,228
Impairment of proved properties and other	—	—	1,281	34,273	35,554
Total costs and expenses	320,598	354,248	382,690	375,112	1,432,648
(Loss) income from continuing operations before income taxes	(69,643)	94,683	(82,910)	82,926	25,056
Income tax (benefit) expense	—	—	—	(1,778)	(1,778)
Current	(27,843)	39,007	(29,074)	31,742	13,832
Deferred	(27,843)	39,007	(29,074)	29,964	12,054
Net (loss) income	$ (41,800)	$ 55,676	$ (53,836)	$ 52,962	$ 13,002
Net (loss) income per common share:					
Basic	$ (0.26)	$ 0.34	$ (0.34)	$ 0.33	$ 0.08
Diluted	$ (0.26)	$ 0.34	$ (0.34)	$ 0.32	$ 0.08

(19) SUPPLEMENTAL INFORMATION ON NATURAL GAS AND OIL EXPLORATION, DEVELOPMENT AND PRODUCTION ACTIVITIES (UNAUDITED)

Our gas natural and oil producing activities are conducted onshore within the continental United States and all of our proved reserves are located within the United States.

Capitalized Costs and Accumulated Depreciation, Depletion and Amortization [(a)]

	December 31,		
	2013	2012	2011
		(in thousands)	
Natural gas and oil properties:			
Properties subject to depletion	$ 8,225,859	$ 7,368,308	$ 6,035,429
Unproved properties	807,022	743,467	748,598
Total	9,032,881	8,111,775	6,784,027
Accumulated depreciation, depletion and amortization	(2,274,444)	(2,015,591)	(1,626,461)
Net capitalized costs	$ 6,758,437	$ 6,096,184	$ 5,157,566

[(a)] Includes capitalized asset retirement costs and the associated accumulated amortization.

Costs Incurred for Property Acquisition, Exploration and Development [a]

	December 31, 2013	2012	2011
		(in thousands)	
Acreage purchases	$ 137,538	$ 188,843	$ 220,576
Development	938,668	1,049,129	1,007,049
Exploration:			
Drilling	189,742	309,816	226,920
Expense	60,384	65,758	77,259
Stock-based compensation expense	4,025	4,049	4,108
Gas gathering facilities:			
Development	47,086	41,035	53,387
Subtotal	1,377,443	1,658,630	1,589,299
Asset retirement obligations	76,373	57,982	24,061
Total – continuing operations	1,453,816	1,716,612	1,613,360
Discontinued operations	—	—	3,241
Total costs incurred	$ 1,453,816	$ 1,716,612	$ 1,616,601

[a] Includes cost incurred whether capitalized or expensed.

Estimated Quantities of Proved Oil and Gas Reserves (Unaudited)

Reserves of natural gas, NGLs, crude oil and condensate are estimated by our petroleum engineering staff and are adjusted to reflect contractual arrangements and royalty rates in effect at the end of each year. Many assumptions and judgmental decisions are required to estimate reserves. Reported quantities are subject to future revisions, some of which may be substantial, as additional information becomes available from reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price changes and other economic factors.

Recent SEC and FASB Rule-Making Activity

In December 2008, the SEC announced that it had approved revisions designed to modernize the natural gas and oil company reserves reporting requirements. We adopted the rules effective December 31, 2009 and the rule changes, including those related to pricing and technology, are included in our reserve estimates for the three years ended December 31, 2013.

Reserve Audit

All reserve information in this report is based on estimates prepared by our petroleum engineering staff. At year-end 2013, the following independent petroleum consultants conducted an audit of our reserves: DeGolyer and MacNaughton (Southwest) and Wright and Company, Inc. (Appalachia). These engineers were selected for their geographic expertise and their historical experience in engineering certain properties. At December 31, 2013, these consultants collectively audited approximately 96% of our proved reserves. Copies of the summary reserve reports prepared by each of these independent petroleum consultants are included as an exhibit to this Annual Report on Form 10-K. The technical person at each independent petroleum consulting firm responsible for reviewing the reserve estimates presented herein meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with our independent petroleum consultants to ensure the integrity, accuracy and timeliness of data furnished to independent petroleum consultants for their reserves audit process. Throughout the year, our technical team meets regularly with representatives of each of our independent petroleum consultants to review properties and discuss methods and assumptions. While we have no formal committee specifically designated to review reserves reporting and the reserves estimation process, our senior management reviews and approves any significant changes to our proved reserves. We provide historical information to our consultants for our largest producing properties such as ownership interest; natural gas and oil production; well test data; commodity prices and operating and development costs. The consultants perform an independent analysis and differences are reviewed with our Senior Vice President of Reservoir Engineering and Economics. In some cases, additional meetings are held to review additional reserve work performed by the technical teams related to any identified reserve differences. The reserve auditor estimates of proved reserves and the pre-tax present value of such reserves discounted at 10% did not differ from our estimates by more than 10% in the aggregate. However, when compared on a lease-by-lease, field-by-field or area-by-area, some of our estimates may be greater than those of the auditors and some may be less than the estimates of the reserve auditors. When such differences do not exceed 10% in the aggregate, our reserve auditors are satisfied that the proved reserves and pre-tax present value of such reserves discounted at 10% are reasonable and will issue an unqualified opinion. Remaining differences are not resolved due to the limited cost benefit of continuing such analysis.

Historical variances between our reserve estimates and the aggregate estimates of our consultants have been less than 5%. All of our reserve estimates are reviewed and approved by our Senior Vice President of Reservoir Engineering and Economics, who reports directly to our President and Chief Executive Officer. Mr. Alan Farquharson, our Senior Vice President of Reservoir Engineering and Economics, holds a Bachelor of Science degree in Electrical Engineering from the Pennsylvania State University. Before joining Range, he held various technical and managerial positions with Amoco, Hunt Oil and Union Pacific Resources. During the year, our reserves group may also perform separate, detailed technical reviews of reserve estimates for significant acquisitions or for properties with problematic indicators such as excessively long lives, sudden changes in performance or changes in economic or operating conditions.

The SEC defines proved reserves as those volumes of natural gas, NGLs, crude oil and condensate that geological and engineering data demonstrate with reasonable certainty are recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are those proved reserves, which can be expected to be recovered from existing wells with existing equipment and operating methods. Proved undeveloped reserves are volumes expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Proved undeveloped reserves can only be assigned to acreage for which improved recovery technology is contemplated when such techniques have been proven effective by actual tests in the area and in the same reservoir. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating each location is scheduled to be drilled within five years from the date it was booked as proved reserves, unless specific circumstances justify a longer time.

The reported value of proved reserves is not necessarily indicative of either fair market value or present value of future net cash flows because prices, costs and governmental policies do not remain static, appropriate discount rates may vary, and extensive judgment is required to estimate the timing of production. Other logical assumptions would likely have resulted in significantly different amounts.

The average realized prices used at December 31, 2013 to estimate reserve information were $86.66 per barrel of oil, $25.93 per barrel of NGLs and $3.75 per mcf for gas, using benchmark (NYMEX) of $97.33 per barrel and $3.67 per Mmbtu. The average realized prices used at December 31, 2012 to estimate reserve information were $86.91 per barrel of oil, $32.23 per barrel of NGLs and $2.75 per mcf for gas, using benchmark (NYMEX) of $95.05 per barrel and $2.76 per MMbtu. The average realized prices used at December 31, 2011 to estimate reserve information were $85.59 per barrel of oil, $49.24 per barrel for NGLs and $3.55 per mcf for gas, using benchmark (NYMEX) of $95.61 per barrel and $4.12 per Mmbtu.

	Natural Gas (Mmcf)	NGLs (Mbbls)	Crude Oil and Condensate (Mbbls)	Natural Gas Equivalents (Mmcfe)
Proved developed and undeveloped reserves:				
Balance, December 31, 2010 [(b)]	3,566,526	122,722	23,239	4,442,290
Revisions	73,643	18,627	6,522	224,542
Extensions, discoveries and additions	1,304,324	26,591	4,915	1,493,357
Purchases	—	—	—	—
Property sales	(777,816)	(19,852)	(1,176)	(903,983)
Production	(157,001)	(5,573)	(1,968)	(202,245)
Balance, December 31, 2011	4,009,676	142,515	31,532	5,053,961
Revisions	76,925	3,036	2,316	109,036
Extensions, discoveries and additions	996,059	113,392	15,131	1,767,202
Purchases	—	—	—	—
Property sales	(73,429)	(11,575)	(1,046)	(149,153)
Production	(216,555)	(6,969)	(2,851)	(275,476)
Balance, December 31, 2012	4,792,676	240,399	45,082	6,505,570
Revisions	384,825	7,743	2,935	448,898
Extensions, discoveries and additions	853,746	135,810	10,723	1,732,944
Purchases	—	—	—	—
Property sales	(101,074)	(286)	(6,553)	(142,116)
Production	(264,528)	(9,254)	(3,827)	(343,022)
Balance, December 31, 2013	5,665,645	374,412	48,360	8,202,274
Proved developed reserves:				
December 31, 2011	1,907,209	64,472	17,872	2,401,274
December 31, 2012	2,373,604	154,984	25,667	3,457,502
December 31, 2013	2,797,483	206,477	26,054	4,192,666
Proved undeveloped reserves:				
December 31, 2011	2,102,467	78,043	13,660	2,652,687
December 31, 2012	2,419,072	85,415	19,415	3,048,068
December 31, 2013	2,868,162	167,935	22,306	4,009,608

(a) Oil and NGLs are converted to mcfe at the rate of one barrel equals six mcf based upon the approximate relative energy content of oil to natural gas, which is not necessarily indicative of the relationship of oil and natural gas prices.

(b) Total proved reserves at December 31, 2010 includes 906,371 Mmcfe related to discontinued operations of which 408,710 Mmcfe is proved undeveloped.

During 2013, we added approximately 1.7 Tcfe of proved reserves from drilling activities and revaluation of proved areas primarily in the Marcellus Shale. Approximately 49% of 2013 reserve additions were attributable to natural gas. Also, included in 2013 proved reserves is a total of 676 Bcfe of ethane reserves (155.8 Mmbbls) in the Marcellus Shale. Revisions of previous estimates of a net 449 Bcfe includes positive performance revisions and improved recovery primarily for our Marcellus Shale natural gas properties and positive pricing revisions, somewhat offset by reserves reclassified to unproved because of a slower pace of development activity beyond the five-year development horizon.

During 2012, we added approximately 1.8 Tcfe of proved reserves from drilling activities and evaluation of proved areas primarily in the Marcellus Shale. Approximately 56% of the 2012 reserve additions were attributable to natural gas. Also included in 2012 additions is 307 Bcfe of ethane reserves (51.2 Mmbbls) in the Marcellus Shale associated with initial ethane deliveries under contracts commencing in 2013. Revisions of previous estimates of a net 109 Bcfe include positive performance revisions primarily for our Marcellus Shale natural gas properties, partially offset by negative pricing revisions.

During 2011, we added approximately 1.5 Tcfe of proved reserves from drilling activities and evaluations of proved areas, primarily in the Marcellus Shale. Approximately 87% of the 2011 reserve additions were attributable to natural gas. Revisions of previous estimates of 225 Bcfe were primarily positive performance revisions for natural gas properties, primarily in the Marcellus Shale.

The following details the changes in proved undeveloped reserves for 2013 (Mmcfe):

Beginning proved undeveloped reserves at December 31, 2012	3,048,068
Undeveloped reserves transferred to developed	(433,526)
Revisions	233,763
Purchases/sales	(23,362)
Extension and discoveries	1,184,665
Ending proved undeveloped reserves at December 31, 2013	4,009,608

Approximately $504.1 million was spent during 2013 related to undeveloped reserves that were transferred to developed reserves. Estimated future development costs of proved undeveloped reserves are projected to be approximately $755.0 million in 2014, $1.3 billion in 2015 and $1.0 billion in 2016. Included in proved undeveloped reserves at December 31, 2013 are approximately 9.3 Bcfe of reserves (less than 1% of total proved undeveloped reserves) that have been reported for five or more years. All proved undeveloped drilling locations are scheduled to be drilled prior to the end of 2018.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves (Unaudited)

The following summarizes the policies we used in the preparation of the accompanying natural gas, NGLs, crude oil and condensate reserve disclosures, standardized measures of discounted future net cash flows from proved natural gas, NGLs and oil reserves and the reconciliations of standardized measures from year to year. The information disclosed is an attempt to present the information in a manner comparable with industry peers.

The information is based on estimates of proved reserves attributable to our interest in natural gas and oil properties as of December 31 of the years presented. These estimates were prepared by our petroleum engineering staff. Proved reserves are estimated quantities of natural gas, NGLs, crude oil and condensate, which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

The standardized measure of discounted future net cash flows from production of proved reserves was developed as follows:

1. Estimates are made of quantities of proved reserves and future amounts expected to be produced based on current year-end economic conditions.
2. For the years ended 2013, 2012 and 2011, estimated future cash inflows are calculated by applying a twelve-month average price of natural gas, NGLs and oil relating to our proved reserves to the quantities of those reserves produced in each future year.
3. Future cash flows are reduced by estimated production costs, administrative costs, costs to develop and produce the proved reserves and abandonment costs, all based on current year-end economic conditions. Future income tax expenses are based on current year-end statutory tax rates giving effect to the remaining tax basis in the natural gas, NGLs and oil properties, other deductions, credits and allowances relating to our proved natural gas and oil reserves.
4. The resulting future net cash flows are discounted to present value by applying a discount rate of 10%.

The standardized measure of discounted future net cash flows does not purport, nor should it be interpreted, to present the fair value of our natural gas, NGLs and oil reserves. An estimate of fair value would also take into account, among other things, the recovery of reserves not presently classified as proved, anticipated future changes in prices and costs and a discount factor more representative of the time value of money and the risks inherent in reserve estimates.

The standardized measure of discounted future net cash flows relating to proved natural gas, NGLs, crude oil and condensate reserves is as follows and excludes cash flows associated with derivatives outstanding at each of the respective reporting dates. Future cash inflows are net of third party transportation, gathering and compression expense.

	As of December 31, 2013	As of December 31, 2012
	(in thousands)	
Future cash inflows	$ 35,143,097	$ 24,851,589
Future costs:		
Production	(10,176,140)	(10,028,359)
Development	(3,938,296)	(3,667,672)
Future net cash flows before income taxes	21,028,661	11,155,558
Future income tax expense	(6,913,196)	(3,081,918)
Total future net cash flows before 10% discount	14,115,465	8,073,640
10% annual discount	(8,253,234)	(4,849,835)
Standardized measure of discounted future net cash flows	$ 5,862,231	$ 3,223,805

The following table summarizes changes in the standardized measure of discounted future net cash flows.

	December 31, 2013	December 31, 2012	December 31, 2011
		(in thousands)	
Revisions of previous estimates:			
Changes in prices	$ 2,172,704	$ (2,498,616)	$ 422,080
Revisions in quantities	513,168	88,190	326,240
Changes in future development costs	(275,468)	(354,766)	(346,378)
Accretion of discount	395,989	608,381	464,735
Net change in income taxes	(1,299,227)	832,830	(400,690)
Purchases of reserves in place	—	—	—
Additions to proved reserves from extensions, discoveries and improved recovery	1,981,054	1,429,340	2,169,706
Production	(1,286,103)	(976,224)	(911,873)
Development costs incurred during the period	462,862	562,329	513,551
Sales of natural gas and oil	(162,463)	(120,637)	(1,313,401)
Timing and other	135,910	(861,919)	111,801
Net change for the year	2,638,426	(1,291,092)	1,035,771
Beginning of year	3,223,805	4,514,897	3,479,126
End of year	$ 5,862,231	$ 3,223,805	$ 4,514,897

RANGE RESOURCES CORPORATION

Range is a leading independent oil and natural gas company with operations in Appalachia and the southwest region of the United States. The Company pursues an organic growth strategy targeting high-return, low-cost projects within its large inventory of low-risk drilling opportunities. At December 31, 2013, Range had 8.2 Tcfe of proved reserves, a 26% increase over the prior year, and a 48% increase in crude oil and NGL volumes over the prior year. In addition, Range estimates 64-85 Tcfe in net unrisked resource potential from its current acreage position. Range's common stock is listed on the New York Stock Exchange under the symbol "RRC." More information about Range can be found at www.rangeresources.com and www.myrangeresources.com.

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JEFFREY L. VENTURA	President & Chief Executive Officer, Range Resources Corporation

Board Committee Membership: [1] Audit, [2] Compensation, [3] Dividend, [4] Governance and Nominating, [5] Lead Director

SENIOR MANAGEMENT

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RODNEY L. WALLER	Senior Vice President & Assistant Secretary

FORM 10-K

Additional copies of the Company's Annual Report on Form 10-K filed with the Securities and Exchange Commission may be obtained upon request from Investor Relations at our headquarters' address.

Range Resources Corporation is traded on the New York Stock Exchange under the symbol "RRC."

Inquiries about the Company should be directed to:

INVESTOR RELATIONS
RANGE RESOURCES CORPORATION
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FORT WORTH, TX 76102
817-870-2601
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TRANSFER AGENT

For assistance regarding a change of address or concerning your stock account, please contact:

COMPUTERSHARE, INC.
P.O. BOX 43078
PROVIDENCE, RI 02940
877-588-4114
HTTPS://WWW-US.COMPUTERSHARE.COM/INVESTOR/CONTACT

Use our web site to obtain the latest news releases and SEC filings:

WWW.RANGERESOURCES.COM

In addition to historical information, this report contains forward-looking statements that may vary materially from actual results. Factors that could cause actual results to differ are included in the Company's Form 10-K for the year ended December 31, 2013, which has been filed with the Securities and Exchange Commission.

Range has posted on its website detailed calculations of EBITDAX, all-in finding costs and drill bit finding cost.

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