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

# Form 10-K

[X] Annual Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the fiscal year ended December 31, 2013

Commission file number 1-08246

# Southwestern Energy Company

(Exact name of registrant as specified in its charter)

| | |
|---|---|
| **Delaware** | **71-0205415** |
| (State or other jurisdiction of incorporation or organization) | (I.R.S. Employer Identification No.) |
| **2350 North Sam Houston Parkway East, Suite 125, Houston, Texas** | **77032** |
| (Address of principal executive offices) | (Zip Code) |

**(281) 618-4700**
(Registrant's telephone number, including area code)

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

| Title of each class | Name of each exchange on which registered |
|---|---|
| Common Stock, Par Value $0.01 | New York Stock Exchange |

**Securities registered pursuant to Section 12(g) of the Act:** None

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

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

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

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐ 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 stock held by non-affiliates of the registrant was $12,840,843,498 based on the New York Stock Exchange – Composite Transactions closing price on June 28, 2013 of $36.53. For purposes of this calculation, the registrant has assumed that its directors and executive officers are affiliates.

As of February 24, 2014, the number of outstanding shares of the registrant's Common Stock, par value $0.01, was 352,930,217.

**Document Incorporated by Reference**

Portions of the registrant's definitive proxy statement to be filed with respect to the annual meeting of stockholders to be held on or about May 20, 2014 are incorporated by reference into Part III of this Form 10-K.

**SOUTHWESTERN ENERGY COMPANY**
**ANNUAL REPORT ON FORM 10-K**
For Fiscal Year Ended December 31, 2013

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This Annual Report on Form 10-K includes certain statements that may be deemed to be “forward-looking” within the meaning of Section 27A of the Securities Act of 1933, or the Securities Act, and Section 21E of the Securities Exchange Act of 1934, or the Exchange Act. We refer you to “Risk Factors” in Item 1A of Part I and to “Management’s Discussion and Analysis of Financial Condition and Results of Operations — Cautionary Statement about Forward-Looking Statements” in Item 7 of Part II of this Form 10-K for a discussion of factors that could cause actual results to differ materially from any such forward-looking statements. The electronic version of this Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and amendments to those forms filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act are available free of charge as soon as reasonably practicable after they are filed with the Securities and Exchange Commission, or SEC, on our website at www.swn.com. Our corporate governance guidelines and the charters of the Audit, the Compensation, and the Nominating and Governance Committees of our Board of Directors are available on our website, and are available in print free of charge to any stockholder upon request. Information on our website is not incorporated into this report.

We file periodic reports and proxy statements with the SEC. The public may read and copy any materials we file with the SEC at the SEC’s Public Reference Room at 100 F Street N.E., Washington, D.C. 20549. The public may obtain information about the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. We file our reports with the SEC electronically. The SEC maintains an internet website that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC. The address of the SEC’s website is www.sec.gov.

## ITEM 1. BUSINESS

Southwestern Energy Company is an independent energy company engaged in natural gas and oil exploration, development and production (E&P). We are also focused on creating and capturing additional value through our natural gas gathering and marketing businesses, which we refer to as Midstream Services. We conduct substantially all of our business through subsidiaries.

*Exploration and Production* - Our primary business is the exploration for and production of natural gas and oil, with our current operations principally focused within the United States on the development of two unconventional natural gas reservoirs located in Arkansas and Pennsylvania. Our operations in Arkansas are primarily focused on an unconventional natural gas reservoir known as the Fayetteville Shale, and our operations in Pennsylvania are focused on the unconventional natural gas reservoir known as the Marcellus Shale. To a lesser extent, we have exploration and production activities ongoing in Texas and in Arkansas and Oklahoma in the Arkoma Basin. We also actively seek to find and develop new oil and natural gas plays with significant exploration and exploitation potential, which we refer to as "New Ventures," and through acquisitions. We conduct our exploration and production operations primarily through our wholly owned subsidiaries SEECO, Inc. ("SEECO"), and Southwestern Energy Production Company ("SEPCO"). SEECO operates exclusively in Arkansas, where it holds a large base of both developed and undeveloped natural gas reserves, and conducts the Fayetteville Shale drilling program and the conventional Arkoma Basin operations. SEPCO conducts development drilling, exploration programs and production operations primarily in Pennsylvania, Oklahoma, Texas, Arkansas and Louisiana. DeSoto Drilling Company, a wholly owned subsidiary of SEPCO, operates drilling rigs in Arkansas and Pennsylvania, as well as in other operating areas. We also provide oilfield products and services through SWN Well Services, L.L.C., an indirect wholly owned subsidiary. We have smaller Canadian operations conducted by our subsidiary SWN International, L.L.C. and its subsidiary, SWN Canada Resources Inc.

*Midstream Services* - We engage in natural gas gathering activities in Arkansas, Texas and Pennsylvania through our subsidiaries DeSoto Gathering Company, L.L.C. ("DeSoto Gathering"), and Angelina Gathering Company, L.L.C. ("Angelina Gathering"). DeSoto Gathering and Angelina Gathering primarily support our E&P operations and generate revenue from fees associated with the gathering of natural gas. Our natural gas marketing subsidiary, Southwestern Energy Services Company ("SES"), captures downstream opportunities that arise through the marketing and transportation of the natural gas produced in our E&P operations.

The vast majority of our operating income and earnings before interest, taxes, depreciation, depletion and amortization and any non-cash impairment of natural gas and oil properties or (gain) loss on derivatives, net of settlement ("Adjusted EBITDA"), are derived from our E&P business. In 2013, 73% of our operating income and 81% of our Adjusted EBITDA were generated from our E&P business, compared to 65% of our operating income, absent our $1,939.7 million, or $1,192.4 million net of taxes, non-cash ceiling test impairment of our natural gas and oil properties, and 79% of our Adjusted EBITDA in 2012, and 77% of our operating income and 84% of our Adjusted EBITDA in 2011. The remainder of our consolidated operating income and Adjusted EBITDA in each of these years was generated from Midstream Services. Adjusted EBITDA is a non-GAAP measure. We refer you to "Business — Other Items — Reconciliation of Non-GAAP Measures" in Item 1 of Part I of this Form 10-K for a table that reconciles Adjusted EBITDA to net income (loss).

### Our Business Strategy

Since 1999, our management has been guided by our formula, which represents the essence of our corporate philosophy and how we operate our business:

$$\frac{R^2}{A} \rightsquigarrow V^{+}\text{®}$$

Our formula, which stands for "The Right People doing the Right Things, wisely investing the cash flow from our underlying Assets will create Value+," also guides our business strategy. We are focused on providing long-term growth in the net asset value of our business. In our E&P business, we prepare an economic analysis for each investment opportunity based upon the expected net present value added for each dollar to be invested, which we refer to as Present Value Index, or PVI. The PVI for each project is determined using a 10% discount rate. We target creating an average of at least $1.30 of pre-tax PVI for each dollar we invest in our E&P projects. Our actual PVI results are utilized to help determine the allocation of our future capital investments. The key elements of our business strategy are:

- *Exploit and Develop Our Positions in the Fayetteville Shale and the Marcellus Shale.* A key focus of the Company is to maximize the value of our significant acreage position in the Fayetteville Shale, which has provided significant production and reserve growth since we began drilling in 2004. As of December 31, 2013, we held approximately 905,684 net acres in the Fayetteville Shale, accounting for approximately 69% of our total proved oil and natural gas reserves and approximately 74% of our total oil and natural gas production during 2013. Additionally, we are actively drilling on portions of our 292,446 net acres in the Marcellus Shale and believe our production and reserves from the Marcellus Shale will grow substantially over the next few years. We intend to develop further our acreage positions in the Fayetteville Shale and the Marcellus Shale and to improve our well results through the use of advanced technologies and detailed technical analysis of our properties.

- *Grow through New Exploration and Development Activities Focusing on Emerging Unconventional Plays*. We actively seek to find and develop new oil and natural gas plays with significant exploration and exploitation potential. Our New Ventures prospects are evaluated based on repeatability, multi-well potential and land availability as well as other criteria, and can be located both inside and outside of the United States. In addition to having E&P employees specifically focused on New Ventures activities, we also have a robust staff of employees focused on strategic business development activities. As of December 31, 2013, we held 3,972,732 net undeveloped acres in connection with our New Ventures prospects, of which 2,518,518 net acres are located in New Brunswick, Canada.

- *Maximize Efficiency through Vertical Integration and Economies of Scale*. In our key operating areas, the concentration of our properties allows us to achieve economies of scale that result in lower costs. We seek to serve as the operator of the wells in which we have a significant interest. As the operator, we are better positioned to control the drilling, completing and producing of wells and the marketing of production to minimize costs and maximize both production volumes and realized price. In the Fayetteville Shale and the Marcellus Shale, we have achieved significant cost savings through our ownership of a sand mine, that is a source of proppant for our well completions, and through our ownership and operation of other associated oilfield services, including a fleet of drilling rigs and two pressure pumping equipment spreads used for well completions.

- *Enhance the Value of Our Midstream Operations*. We have continued to design and improve our gas gathering infrastructure to manage better the physical movement of our production. As of December 31, 2013, we have invested approximately $1,096 million in the 1,947 mile gas gathering system built for our Fayetteville Shale asset, which was gathering approximately 2.3 Bcf per day at year-end, and have invested approximately $213 million in 124 miles of gas gathering lines in Pennsylvania, Louisiana and East Texas. Our gathering systems in the Fayetteville Shale and the Marcellus Shale have developed into strategic assets that not only support our E&P operations but also have improved our overall returns on a stand-alone basis.

**Significant Accomplishments in 2013**

*Production and Reserve Growth.* In 2013, our production was 656.8 Bcfe, or approximately 1.8 Bcfe per day, an increase of 16% from 2012 levels. This increase was driven primarily by our production growth of 181% from the Marcellus Shale. Additionally, in 2013 our total proved reserves increased to the highest level in our company's history, growing by 74% to approximately 7.0 Tcfe.

*Low Cost Structure.* Our cost structure continues to be one of the lowest in the industry, with an all-in cash operating cost of $1.25 per Mcfe in 2013, compared to $1.20 per Mcfe in 2012. All-in cash operating cost per Mcfe is defined as the per Mcfe sum of our E&P segment's lease operating expenses, taxes (other than income taxes), general and administrative expenses, and net interest expense. We have included information concerning this ratio because it measures the cost efficiency of a company's oil and gas producing operations and is a measure commonly used in our industry.

*Marcellus Shale Achieves Significant Growth.* Our Marcellus Shale division drove our overall production growth in 2013, with gross operated production reaching nearly 700 MMcf per day at year-end 2013 compared to 300 MMcf per day at year-end 2012. Production nearly tripled to 150.6 Bcf in 2013, compared to 53.6 Bcf in 2012, while total proved reserves more than doubled to approximately 2.0 Tcf, compared to 816 Bcf in 2012.

*Fayetteville Shale Continues to Deliver.* In 2013, our Fayetteville Shale division had one of its best years ever. The division not only surpassed the milestone of 3 Tcf of cumulative gross operated production, but it also achieved its highest average initial production rate per well, all the while achieving its lowest average cost per well since we announced the Fayetteville Shale in 2004. Total proved reserves for the Fayetteville Shale increased in 2013 to approximately 4.8 Tcf, from 3.0 Tcf in 2012, and 2013 production of 486.0 Bcf was flat compared to 2012 levels.

*Financial Flexibility.* We ended 2013 with a capital structure that consisted of 35% debt and 65% equity and had approximately $1.7 billion of borrowing capacity available under our principal credit facility. At December 31, 2013, our debt was rated as investment grade by all three of the major rating agencies: "BBB-" with a stable outlook by Standard and

Poor's (S&P), "BBB-" with a stable outlook by Fitch Ratings (Fitch) and "Baa3" with a stable outlook by Moody's Investors Service (Moody's).

**Recent Developments**

*2014 Planned Capital Investments and Production Guidance.* Our planned capital investment program for 2014 is approximately $2.3 billion, which includes approximately $2.0 billion for our E&P segment, $140 million for our Midstream Services segment and $150 million for E&P Services and corporate, $95 million of which is for the purchase of drilling rigs. Our 2014 capital program is expected to be funded primarily by our cash flow from operations assuming current market prices. The planned capital program for 2014 is flexible, and we will reevaluate our proposed investments as needed to take into account prevailing market conditions. Based on our capital program, we are targeting 2014 natural gas and oil production of approximately 740 to 752 Bcfe, an increase of approximately 14% over our 2013 production, using midpoints.

*Credit Facility Expansion.* In December 2013, we entered into a new Credit Agreement with JPMorgan Chase Bank, N.A., as Administrative Agent, and other lenders (the "Credit Facility"). Under the Credit Facility, we have a borrowing capacity of $2.0 billion and a maturity date of December 14, 2018 with options for two one-year extensions with the approval of participating lenders. The amount available under the Credit Facility can be increased by up to an additional $500 million in the future upon the agreement between us and participating lenders. The Credit Facility is unsecured, is not guaranteed by any subsidiaries of the Company, and replaced the Company's $1.5 billion unsecured revolving credit facility that was due to expire in February 2016.

**Exploration and Production**

***Overview***

Operations in our E&P segment are primarily in the Fayetteville Shale and the Marcellus Shale assets. We also intend to conduct additional exploration and production activities in the Lower Smackover Brown Dense, or LSBD, conventional and unconventional operations targeting various formations as part of our New Ventures projects and exploration activities in New Brunswick, Canada. We continue to actively seek to acquire and develop both conventional and unconventional natural gas and oil resource plays with significant exploration and exploitation potential.

Our E&P segment recorded operating income of $878.7 million in 2013, an operating loss of $1,396.3 million in 2012 as a result of the recognition of a $1,939.7 million, or $1,192.4 million net of taxes, non-cash ceiling test impairment of our United States natural gas and oil properties, and operating income of $823.6 million in 2011. Operating income for 2013 increased $335.2 million compared to 2012 (excluding the $1,939.7 million non-cash ceiling test impairment recorded in 2012) as a result of an increase in revenue of $315.6 million from higher natural gas production volumes, an increase in revenue of $118.0 million from increased prices realized from the sale of our natural gas production and an increase in revenues of $5.6 million from higher oil volumes, offset by an increase in operating costs and expenses of $105.8 million associated with the expansion of our operations and higher activity levels in the Fayetteville Shale and the Marcellus Shale. Operating income for 2012 (excluding the $1,939.7 million non-cash ceiling test impairment recorded in 2012) decreased $280.1 million compared to 2011 as the revenue impact of our 13% increase in production was more than offset by the 18% decline in our average realized gas prices and an increase in operating costs and expenses that resulted from our higher activity levels. Adjusted EBITDA from our E&P segment was $1.6 billion in 2013, compared to $1.3 billion in 2012 and $1.5 billion in 2011. Our Adjusted EBITDA increased in 2013 as higher realized gas prices and production volumes more than offset increased total operating costs and expenses due to increased activity levels. Our Adjusted EBITDA decreased in 2012 as our increased production was more than offset by lower average realized gas prices and increased operating costs and expenses that resulted from our higher activity levels. Adjusted EBITDA is a non-GAAP measure. We refer you to "Business — Other Items — Reconciliation of Non-GAAP Measures" in Item 1 of Part I of this Form 10-K for a reconciliation of Adjusted EBITDA to net income (loss).

***Oilfield Services Vertical Integration***

We seek to provide oilfield services internally that are strategic and economically beneficial for our E&P operations. This vertical integration lowers our net well costs, allows us to operate safely and efficiently and mitigates certain operational environmental risks. Among others, these services include drilling, hydraulic fracturing and the mining of proppant used for our well completions.

Sand Mine

Since 2009, we have owned and operated a sand mine to provide a reliable supply of proppant primarily used for the completion of our wells that we operate in the Fayetteville Shale. As of December 31, 2013, our sand mine is comprised of 570 acres and produces 30/70 and 100 mesh sized sand. In 2013, we provided sand for the completion of 382 wells operated by us in the Fayetteville Shale and were able to reduce our well completion costs on average by 12% per well for the wells for which we provided sand.

Hydraulic Fracturing

SWN Well Services, L.L.C. provides pressure pumping services for a portion of our operated wells. As of December 31, 2013, we operated two leased pressure pumping spreads with a total capacity of approximately 81,000 horsepower to conduct a variety of completion services designed to stimulate natural gas production. In 2013, we provided pressure pumping services for 155 wells that we operated in the Fayetteville Shale and were able to reduce our well completion costs on average by 9% per well for the wells we completed.

Drilling Services

Our wholly owned subsidiary Desoto Drilling conducts drilling operations for our operated wells. It sometimes conducts business under the registered assumed name SWN Drilling Company. As of December 31, 2013, we operated 11 re-entry rigs and 2 spudder rigs which were operating in Arkansas, Pennsylvania and Louisiana. In 2013, we provided drilling services for 414 and 41 wells that we operate in the Fayetteville Shale and the Marcellus Shale, respectively, and were able to reduce our drilling costs on average by 4% and 2% per well for the wells we drilled in the Fayetteville Shale and the Marcellus Shale, respectively.

***Our Proved Reserves***

Our estimated proved natural gas and oil reserves were 6,976 Bcfe at year-end 2013, compared to 4,018 Bcfe at year-end 2012 and 5,893 Bcfe at year-end 2011. The significant increase in our reserves in 2013 was primarily due to our successful development drilling programs in the Fayetteville Shale and the Marcellus Shale and the higher natural gas price environment compared to 2012. Because our proved reserves are primarily natural gas, our reserve estimates and the after-tax PV-10 measure, or standardized measure of discounted future net cash flows relating to proved natural gas and oil reserve quantities, are highly dependent upon the natural gas price used in the after-tax PV-10 calculation. The average prices utilized to value our estimated proved natural gas and oil reserves as of December 31, 2013 were $3.67 per MMBtu for natural gas, $93.42 per barrel for oil and $43.45 per barrel for NGLs compared to $2.76 per MMBtu for natural gas and $91.21 per barrel for oil at December 31, 2012 and $4.12 per MMBtu for natural gas and $92.71 per barrel for oil at December 31, 2011.

Our after-tax PV-10 was $3.7 billion at year-end 2013, $2.1 billion at year-end 2012, and $3.5 billion at year-end 2011. The increase in our after-tax PV-10 value in 2013 was primarily caused by an increase in our reserves and higher average natural gas prices in 2013. The decrease in our after-tax PV-10 value in 2012 over 2011 was principally due to price revisions, primarily due to lower average natural gas prices in 2012. The difference in after-tax PV-10 and pre-tax PV-10 (a non-GAAP measure which is reconciled in the 2013 Proved Reserves by Category and Summary Operating Data table below) is the discounted value of future income taxes on the estimated cash flows. Our year-end 2013 estimated proved reserves had a present value of estimated future net cash flows before income tax, or pre-tax PV-10, of $5.1 billion, compared to $2.3 billion at year-end 2012 and $4.8 billion at year-end 2011.

We believe that the pre-tax PV-10 value of the estimated cash flows related to our estimated proved reserves is a useful supplemental disclosure to the after-tax PV-10 value. While pre-tax PV-10 is based on prices, costs and discount factors that are comparable from company to company, the after-tax PV-10 is dependent on the unique tax situation of each individual company. We understand that securities analysts use pre-tax PV-10 as one measure of the value of a company's current proved reserves and to compare relative values among peer companies without regard to income taxes. We refer you to Note 4 in the consolidated financial statements for a discussion of our standardized measure of discounted future cash flows related to our proved gas and oil reserves, to the risk factor "Although our estimated natural gas and oil reserve data is independently audited, our estimates may still prove to be inaccurate" in Item 1A of Part I of this Form 10-K, and to "Management's Discussion and Analysis of Financial Condition and Results of Operations — Cautionary Statement about Forward-Looking Statements" in Item 7 of Part II of this Form 10-K for a discussion of the risks inherent in utilization of standardized measures and estimated reserve data.

Virtually 100% of our year-end 2013 estimated proved reserves were natural gas and 61% were classified as proved developed, compared to 100% and 80%, respectively, in 2012 and 100% and 55%, respectively in 2011. We operate or if operations have not commenced, plan to operate, approximately 98% of our reserves, based on the pre-tax PV-10 value of our proved developed producing reserves, and our reserve life index approximated 10.6 years at year-end 2013. Natural gas sales accounted for nearly 100% of total operating revenues for the E&P segment in 2013, 2012 and 2011.

The following table provides an overall and categorical summary of our oil and natural gas reserves, as of fiscal year-end 2013 based on average fiscal year prices, and our well count, net acreage and PV-10 as of December 31, 2013 and sets forth 2013 annual information related to production and capital investments for each of our operating areas:

**2013 PROVED RESERVES BY CATEGORY AND SUMMARY OPERATING DATA**

| | | | Ark-La-Tex | | | |
|---|---|---|---|---|---|---|
| | **Fayetteville Shale** | **Marcellus Shale** | **East Texas** | **Arkoma Basin** | **New Ventures** | **Total** |
| Estimated Proved Reserves: | | | | | | |
| Natural Gas (Bcf): | | | | | | |
| Developed (Bcf) | 3,140 | 888 | 56 | 152 | 1 | **4,237** |
| Undeveloped (Bcf) | 1,655 | 1,075 | 2 | 5 | – | **2,737** |
| | 4,795 | 1,963 | 58 | 157 | 1 | **6,974** |
| Crude Oil (MMBbls): | | | | | | |
| Developed (MMBbls) | – | – | 0.1 | – | 0.3 | **0.4** |
| Undeveloped (MMBbls) | – | – | – | – | – | – |
| | – | – | 0.1 | – | 0.3 | **0.4** |
| Total Proved Reserves (Bcfe)(1): | | | | | | |
| Developed (Bcfe) | 3,140 | 888 | 56 | 152 | 3 | **4,239** |
| Undeveloped (Bcfe) | 1,655 | 1,075 | 2 | 5 | – | **2,737** |
| | 4,795 | 1,963 | 58 | 157 | 3 | **6,976** |
| Percent of Total | 69% | 28% | 1% | 2% | – | **100%** |
| | | | | | | |
| Percent Proved Developed | 65% | 45% | 97% | 97% | 100% | **61%** |
| Percent Proved Undeveloped | 35% | 55% | 3% | 3% | – | **39%** |
| | | | | | | |
| Production (Bcfe) | 486 | 151 | 6 | 12 | 2 | **657** |
| Capital Investments (millions)(2) | $ 907 | $ 872 | $ 3 | $ 4 | $ 191 | **$ 1,977** |
| Total Gross Producing Wells(3) | 3,539 | 334 | 173 | 1,164 | 3 | **5,213** |
| Total Net Producing Wells(3) | 2,432 | 171 | 109 | 566 | 3 | **3,281** |
| | | | | | | |
| Total Net Acreage | 781,464 (4) | 292,446 (5) | 50,451 (6) | 226,706 (7) | 3,976,002 (8) | **5,327,069** |
| Net Undeveloped Acreage | 291,360 (4) | 246,838 (5) | 172 (6) | 60,375 (7) | 3,972,732 (8) | **4,571,477** |
| | | | | | | |
| PV-10: | | | | | | |
| Pre-tax (millions)(9) | $ 3,690 | $ 1,202 | $ 62 | $ 163 | $ 12 | **$ 5,129** |
| PV of taxes (millions)(9) | 1,002 | 327 | 17 | 44 | 3 | **1,393** |
| After-tax (millions)(9) | $ 2,688 | $ 875 | $ 45 | $ 119 | $ 9 | **$ 3,736** |
| Percent of Total | 72% | 24% | 1% | 3% | – | **100%** |
| Percent Operated(10) | 98% | 99% | 97% | 88% | 100% | **98%** |

(1) We have no reserves from synthetic gas, synthetic oil or nonrenewable natural resources intended to be upgraded into synthetic gas or oil. We used standard engineering and geoscience methods, or a combination of methodologies in determining estimates of material properties, including performance and test date analysis offset statistical analogy of performance data, volumetric evaluation, including analysis of petrophysical parameters (including porosity, net pay, fluid saturations (i.e., water, oil and gas) and permeability) in combination with estimated reservoir parameters (including reservoir temperature and pressure, formation depth and formation volume factors), geological analysis, including structure and isopach maps and seismic analysis, including review of 2-D and 3-D data to ascertain faults, closure and other factors.

(2) Our Total and Fayetteville Shale capital investments exclude $76 million related to our drilling rig related equipment, sand facility and other equipment.

(3) Represents all producing wells, including wells in which we only have an overriding royalty interest, as of December 31, 2013.

(4) Assuming successful wells are not drilled to develop the acreage and leases are not extended, leasehold expiring over the next three years will be 22,092 net acres in 2014, 16,305 net acres in 2015, and 1,803 net acres in 2016 (excluding 155,852 net acres held on federal lands which are currently suspended by the Bureau of Land Management).

(5) Assuming successful wells are not drilled to develop the acreage and leases are not extended, leasehold expiring over the next three years will be 65,537 net acres in 2014, 32,637 net acres in 2015 and 19,233 net acres in 2016.

(6) Assuming successful wells are not drilled to develop the acreage and leases are not extended, leasehold expiring over the next three years will be 27 net acres in 2014, 64 net acres in 2015 and zero net acres in 2016.

(7) Includes 123,442 net developed acres and 778 net undeveloped acres in the Arkoma Basin that are also within our Fayetteville Shale focus area but not included in the Fayetteville Shale acreage in the table above. Assuming successful wells are not drilled to develop the acreage and leases are not extended, leasehold expiring over the next three years will be 262 net acres in 2014, 7,437 net acres in 2015 and 574 net acres in 2016.

(8) Assuming successful wells are not drilled to develop the acreage and leases are not extended, our leasehold expiring over the next three years, excluding New Brunswick, Canada and the LSBD area, will be 65,628 net acres in 2014, 143,708 net acres in 2015 and 273,306 net acres in 2016. With regard to the Company's acreage in New Brunswick, Canada, 2,518,518 net acres will expire in March 2015. We are in the process of applying for an additional 1-year option to extend our exploration license agreements and, if granted by the Province of New Brunswick, this would extend our exploration license agreements until March 2016. With regard to our acreage in the LSBD, assuming successful wells are not drilled and leases are not extended, leasehold expiring over the next three years will be 245,793 net acres in 2014, 151,667 net acres in 2015 and 25,891 net acres in 2016.

(9) Pre-tax PV-10 (a non-GAAP measure) is one measure of the value of a company's proved reserves that we believe is used by securities analysts to compare relative values among peer companies without regard to income taxes. The reconciling difference in pre-tax PV-10 and the after-tax PV-10, or standardized measure, is the discounted value of future income taxes on the estimated cash flows from our proved oil and natural gas reserves.

(10) Based upon pre-tax PV-10 of proved developed producing properties.

We refer you to Note 4 in our consolidated financial statements for a more detailed discussion of our proved gas and oil reserves as well as our standardized measure of discounted future net cash flows related to our proved gas and oil reserves. We also refer you to the risk factor "Although our estimated natural gas and oil reserve data is independently audited, our estimates may still prove to be inaccurate" in Item 1A of Part I of this Form 10-K and to "Management's Discussion and Analysis of Financial Condition and Results of Operations — Cautionary Statement about Forward-Looking Statements" in Item 7 of Part II of this Form 10-K for a discussion of the risks inherent in utilization of standardized measures and estimated reserve data.

Proved Undeveloped Reserves

Presented below is a summary of changes in our proved undeveloped reserves for 2013, 2012 and 2011.

**Changes in Proved Undeveloped Reserves (Bcfe)**

| | Fayetteville Shale | Marcellus Shale | Ark-La-Tex East Texas | Ark-La-Tex Arkoma Basin | Total |
|---|---|---|---|---|---|
| **December 31, 2010** | **2,132** | **27** | **55** | **29** | **2,243** |
| Extensions, discoveries and other additions | 688 | 155 | 5 | – | **848** |
| Total revision attributable to performance and production | (28) | 14 | (5) | (7) | **(26)** |
| Price revisions | (1) | (4) | (1) | (1) | **(7)** |
| Developed | (376) | (22) | (6) | – | **(404)** |
| Disposition of reserves in place | – | – | (21) | – | **(21)** |
| Acquisition of reserves in place | – | – | – | – | – |
| **December 31, 2011** | **2,415** | **170** | **27** | **21** | **2,633** |
| Extensions, discoveries and other additions | 32 | 305 | – | – | **337** |
| Total revision attributable to performance and production | (239) | 16 | – | – | **(223)** |
| Price revisions | (1,401) | 1 | (26) | (7) | **(1,433)** |
| Developed | (443) | (50) | – | – | **(493)** |
| Disposition of reserves in place | – | – | – | – | – |
| Acquisition of reserves in place | – | – | – | – | – |
| **December 31, 2012** | **364** | **442** | **1** | **14** | **821** |
| Extensions, discoveries and other additions [(1)] | 1,530 | 810 | – | – | **2,340** |
| Total revision attributable to performance and production | (115) | (33) | – | (9) | **(157)** |
| Price revisions | 18 | 26 | 1 | – | **45** |
| Developed | (142) | (170) | – | – | **(312)** |
| Disposition of reserves in place | – | – | – | – | – |
| Acquisition of reserves in place | – | – | – | – | – |
| **December 31, 2013** | **1,655** | **1,075** | **2** | **5** | **2,737** |

(1) The 2013 PUD additions are primarily associated with the increase in gas prices.

As of December 31, 2013, we had 2,737 Bcfe of proved undeveloped reserves, all of which we expect will be developed within five years of the initial disclosure as the starting reference date. During 2013, we invested $248 million in connection with converting 312.3 Bcfe or 38% of our proved undeveloped reserves as of December 31, 2012, into proved developed reserves and added 2,340 Bcfe of proved undeveloped reserve additions in the Fayetteville Shale and the Marcellus Shale. As of December 31, 2012, we had 821 Bcfe of proved undeveloped reserves, all of which we expect will be developed within five years of the initial disclosure as the starting reference date. During 2012, we invested $518 million in connection with converting 493.2 Bcfe or 19% of our proved undeveloped reserves as of December 31, 2011 into proved developed reserves and added 336.8 Bcfe of proved undeveloped reserve additions in the Fayetteville Shale and the Marcellus Shale.

The development of our proved undeveloped reserves will require us to make significant additional investments. We expect that the development costs for our proved undeveloped reserves of 2,737 Bcfe as of December 31, 2013 will require us to invest an additional $3.1 billion for those reserves to be brought to production. Our ability to make the necessary investments to generate these cash inflows is subject to factors that may be beyond our control. A significant decrease in price levels for an extended period of time could result in certain reserves no longer being economic to produce, leading to both lower proved reserves and cash flows. We refer you to the risk factors “A substantial or extended decline in natural gas and oil prices would have a material adverse effect on us,” “We may have difficulty financing our planned capital investments, which could adversely affect our growth” and “Our level of indebtedness and the terms of our financing arrangements may adversely affect operations and limit our growth” in Item 1A of Part I of this Form 10-K and to “Management’s Discussion and Analysis of Financial Condition and Results of Operations — Cautionary Statement about Forward-Looking Statements” in Item 7 of Part II of this Form 10-K for a more detailed discussion of these factors and other risks.

***Our Reserve Replacement***

The reserve replacement ratio measures the ability of an exploration and production company to add new reserves to replace the reserves that are being depleted by its current production volumes. The reserve replacement ratio, which we discuss below, is an important analytical measure used by investors and peers in the E&P industry to evaluate performance results and long-term prospects. There are limitations as to the usefulness of this measure, as it does not reflect the type of reserves or the cost of adding the reserves or indicate the potential value of the reserve additions.

In 2013, we replaced 550% of our production volumes with 3,285 Bcfe of proved reserve additions, net upward revisions of 326 Bcfe, and 4 Bcfe of proved reserve additions as a result of acquisitions. Of the reserve additions, 945 Bcfe were proved developed and 2,340 Bcfe were proved undeveloped. In 2013, upward reserve revisions resulting from higher gas prices totaled 191 Bcf, 35 Bcf and 21 Bcf in the Fayetteville Shale, the Marcellus Shale and our Ark-La-Tex division, respectively. We also had upward performance revisions in 2013 of 16 Bcf, 62 Bcf and 1 Bcf in the Fayetteville Shale, the Marcellus Shale, and our New Ventures division, respectively. Additionally, our reserves increased by 4 Bcf in 2013 as a result of our acquisition of natural gas leases and wells.

In 2012, we replaced our production volumes with 920 Bcfe of proved reserve additions as a result of our drilling and acquisition program but also incurred net downward revisions of 2,088 Bcfe principally due to a decrease in the price of natural gas and to a lesser extent due to downward performance revisions of 336 Bcfe. Of the reserve additions, 583 Bcfe were proved developed and 337 Bcfe were proved undeveloped. The total downward reserve revisions were primarily impacted by the low commodity price environment in 2012 and to a lesser extent by downward performance revisions. In 2012, downward reserve revisions resulting from lower gas prices totaled 1,684 Bcf, 9 Bcf and 59 Bcf in the Fayetteville Shale, the Marcellus Shale, and our Ark-La-Tex division, respectively. We also had a net downward performance revision in 2012 of 362 Bcf and 10 Bcf in the Fayetteville Shale and our Ark-La-Tex division, respectively. We had a net positive performance revision in 2012 of 36 Bcf in the Marcellus Shale. Additionally, our reserves decreased by 141 Bcf in 2012 as a result of our disposition of natural gas leases and wells.

In 2011, we replaced 299% of our production volumes with an increase of 1,459 Bcfe of proved gas and oil reserves as a result of our drilling program and net upward revisions of 34 Bcfe. Of the reserve additions, 612 Bcfe were proved developed and 847 Bcfe were proved undeveloped. The upward reserve revisions during 2011 were primarily comprised of 103 Bcf in upward revisions related to the improved performance of our wells in the Marcellus Shale, partially offset by downward performance revisions of 28 Bcfe and 18 Bcfe in our East Texas and conventional Arkoma Basin operating areas, respectively. We also had downward performance revisions in the Fayetteville Shale of 14 Bcfe. Additionally, our reserves decreased by 9 Bcfe due to a drop in the average gas price for 2011 as compared to 2010. In addition, our reserves decreased by 37 Bcfe as a result of our sale of oil and natural gas leases and wells in 2011.

For the period ending December 31, 2013, our three-year average reserve replacement ratio, including revisions and acquisitions, was 229%. Our reserve replacement ratio for 2013, excluding the effect of reserve revisions, was 501%, compared to 163% in 2012 and 292% in 2011. Excluding reserve revisions and acquisitions, our three-year average reserve replacement ratio was 329%.

Since 2005, the substantial majority of our reserve additions have been generated from our Fayetteville Shale. However, over the past several years the Marcellus Shale has also contributed to an increasing amount of our reserve additions, totaling 1,200 Bcf, 500 Bcf and 229 Bcf in 2013, 2012 and 2011, respectively. We expect our drilling programs in the Fayetteville Shale and the Marcellus Shale to continue to be the primary source of our reserve additions in the future; however, our ability to add reserves depends upon many factors that are beyond our control. We refer you to the risk factors “Our drilling plans for the Fayetteville Shale and the Marcellus Shale are subject to change” and “Our exploration, development and drilling efforts and our operation of our wells may not be profitable or achieve our targeted returns” in Item 1A of Part I of this Form 10-K and to “Management’s Discussion and Analysis of Financial Condition and Results of

Operations — Cautionary Statement about Forward-Looking Statements" in Item 7 of Part II of this Form 10-K for a more detailed discussion of these factors and other risks.

***Our Operations***

Fayetteville Shale

Our Fayetteville Shale properties are one of the two primary focus areas of our exploration and production business. The Fayetteville Shale is a Mississippian-age unconventional gas reservoir located on the Arkansas side of the Arkoma Basin, ranging in thickness from 50 to 550 feet and ranging in depth from 1,500 to 6,500 feet. As of December 31, 2013, we held leases for approximately 905,684 net acres in the play area (291,360 net undeveloped acres, 490,104 net developed acres held by Fayetteville Shale production, 123,442 net acres held by conventional production in the Arkoma Basin, and 778 net undeveloped acres in the Arkoma Basin), compared to approximately 913,502 net acres at year-end 2012 and 925,842 net acres at year-end 2011.

Approximately 4,795 Bcf of our reserves at year-end 2013 were attributable to our Fayetteville Shale properties, compared to approximately 2,988 Bcf at year-end 2012 and 5,104 Bcf at year-end 2011. Our reserves in the Fayetteville Shale increased by 1,807 Bcf in 2013, which included reserve additions of 2,087 Bcf, net upward price revisions of 190 Bcf, 16 Bcf of net upward revisions due to well performance, offset by production of 486 Bcf. Our net production from the Fayetteville Shale was 486 Bcf in 2013, compared to 486 Bcf in 2012 and 437 Bcf in 2011. In 2014, we estimate our net production from the Fayetteville Shale will be in the range of 479 to 484 Bcf.

At year-end 2013, after excluding our acreage in the conventional Arkoma Basin and the federal acreage we hold in the Ozark Highlands Unit, approximately 80% of our 628,975 total net leasehold acres remaining in the Fayetteville Shale was held by production. For more information about our acreage and well count, we refer you to "Properties" in Item 2 of Part 1 of this Form 10-K. Excluding our acreage in the conventional Arkoma Basin, our acreage position was obtained at an average cost of approximately $320 per acre and has an average royalty interest of 15%. In 2014, we expect to earn 11 sections, or approximately 3,969 net acres, representing 2% of our drilling program. As of December 31, 2013, excluding our acreage in the conventional Arkoma Basin and our federal acreage, the undeveloped portion of our acreage had an average remaining lease term of 1 year. We refer you to the risk factor "If we fail to drill all of the wells that are necessary to hold our acreage, the initial lease terms could expire, which would result in the loss of certain leasehold rights" in Item 1A of Part I of this Form 10-K.

Following the commencement of two court actions, now consolidated, alleging deficiencies in the Environmental Impact Statement issued in connection with the grant of the leases by the Bureau of Land Management (BLM) in the Ozark National Forest, the BLM has discontinued approval of operational permits in the forest, including permits to drill, pending resolution of the litigation. The Ozark Highlands Unit lies entirely within the Ozark National Forest. Although the Company is not a party to the litigation and the plaintiffs' complaints do not seek invalidation of the leases, we currently are unable to obtain permits to drill on the 195,619 acres we have leased in the unit and the national forest. The period to drill to maintain leases has been extended pending resolution of this litigation on all but 2,832 of these net acres.

As of December 31, 2013, we had spud a total of 4,110 wells in the Fayetteville Shale since its commencement in 2004, of which 3,538 were operated by us and 572 were outside-operated wells. Of these wells, 527 were spud in 2013, 491 in 2012 and 650 in 2011. Of the wells spud in 2013, 525 were designated as horizontal wells. At year-end 2013, 3,288 wells operated by the Company had been drilled and completed overall, including 3,197 horizontal wells. Of the 3,197 horizontal wells, 3,179 wells were fracture stimulated using either slickwater or crosslinked gel stimulation treatments, or a combination thereof.

Over the past several years, we have seen continuous improvement in our drilling practices in the Fayetteville Shale. In 2013, the horizontal wells we drilled as operator had an average completed well cost of $2.4 million per well, average horizontal lateral length of 5,356 feet, and an average time to drill to total depth of 6.2 days from re-entry to re-entry. This compares to an average completed operated well cost of $2.5 million per well, average horizontal lateral length of 4,833 feet and average time to drill to total depth of 6.7 days from re-entry to re-entry during 2012. In 2011, our average completed operated well cost was $2.8 million per well with an average horizontal lateral length of 4,836 feet and average time to drill to total depth of 7.9 days from re-entry to re-entry. The operated wells we placed on production during 2013 averaged initial production rates of 4,041 Mcf per day, compared to average initial production rates of 3,629 Mcf per day in 2012 and 3,330 Mcf per day in 2011. In 2013, our initial production rates increased, compared to initial production rates in 2012 as a result of longer lateral lengths, improved well bore placement, and further refined completion and flowback techniques. The increase in initial production rates for 2012, compared to the initial production rates of the preceding year, is primarily due to the optimization of our drilling plan toward areas in the field with the highest-return wells. During

2013, we placed 91 operated wells on production with initial production rates that exceeded 5.0 MMcf per day, compared to 60 wells in 2012 and 51 wells in 2011.

Our total proved net reserves booked in the Fayetteville Shale at year-end 2013 were from a total of 4,631 locations, of which 3,511 were proved developed producing, 59 were proved developed non-producing and 1,061 were proved undeveloped. Of the 4,631 locations, 4,614 were horizontal. The average gross proved reserves for the undeveloped wells included at year-end 2013 was approximately 2.5 Bcf per well, compared to 2.8 Bcf per well at year-end 2012, and 2.4 Bcf per well at year-end 2011. The decrease in average gross proved reserves for our undeveloped wells in 2013 was primarily due to the addition of over 800 proven undeveloped locations with lower estimated ultimate recoveries that were added due to the higher gas price environment. The increase in average gross proved reserves for our undeveloped wells in 2012 was primarily due to the estimated ultimate recoveries of those locations which remained economic at the average prices utilized during 2012. Total proved net natural gas reserves booked in the Fayetteville Shale in 2012 were approximately 2,988 Bcf from a total of 3,508 locations, of which 3,175 were proved developed producing, 123 were proved developed non-producing and 210 were proved undeveloped. Total proved net natural gas reserves booked in the play in 2011 totaled approximately 5,104 Bcf from a total of 4,376 locations, of which 2,735 were proved developed producing, 59 were proved developed non-producing and 1,582 were proved undeveloped.

In 2013, we invested approximately $907 million in the Fayetteville Shale, which included approximately $804 million to spud 527 wells, 504 of which we operate. Included in our total capital investments in the Fayetteville Shale during 2013 was $97 million in capitalized costs and other expenses and $6 million for acquisition of properties. In 2012, we invested approximately $991 million in the Fayetteville Shale, which included $877 million to spud 491 wells, 453 of which we operate, $4 million for acquisition of properties, and $110 million in capitalized costs and other expenses. In 2011, we invested approximately $1.3 billion in the Fayetteville Shale, which included $1.2 billion to spud 650 wells, $10 million for acquisition of properties and $132 million in capitalized costs and other expenses. As of December 31, 2013, we had acquired approximately 1,324 square miles of 3-D seismic data, which provides us with seismic data on approximately 65% of our net acreage position in the Fayetteville Shale, excluding our acreage in the Arkoma Basin.

In 2014, we plan to invest approximately $900 million in our Fayetteville Shale properties, which includes participating in approximately 460 to 470 gross wells, all of which we plan to operate.

We believe that our Fayetteville Shale acreage continues to have significant development potential. Our strategy is to continue our development drilling, increase the amount of acreage we hold by production and determine the economic viability of the undrilled portion of our acreage. Our drilling program with respect to our Fayetteville Shale properties is flexible and will be impacted by a number of factors, including the results of our horizontal drilling efforts, our ability to determine the most effective and economic fracture stimulation methods and well spacing, the extent to which we can replicate the results of our most successful Fayetteville Shale wells in other Fayetteville Shale acreage and the natural gas commodity price environment. As we continue to gather data about the Fayetteville Shale, it is possible that additional information may cause us to alter our drilling schedule or determine that prospects in some portion of our acreage position should not be pursued at all. We refer you to the risk factor "Our drilling plans for the Fayetteville Shale and the Marcellus Shale are subject to change" in Item 1A of Part I of this Form 10-K.

Marcellus Shale

We began leasing acreage in northeastern Pennsylvania in 2007 in an effort to participate in the emerging Marcellus Shale. As of December 31, 2013, we had approximately 292,446 net acres in Pennsylvania under which we believe the Marcellus Shale is present (246,838 net undeveloped acres and 45,608 net developed acres held by production), compared to approximately 176,298 net acres at year-end 2012 and 186,893 net acres at year-end 2011. Our undeveloped acreage position as of December 31, 2013 had an average remaining lease term of 3 years and an average royalty interest of 15% and was obtained at an average cost of approximately $1,232 per acre. Included in the acreage numbers above is approximately 162,000 net acres in the Marcellus Shale that we acquired in 2013 for approximately $93 million. The acquired acreage is near our existing acreage in the Marcellus Shale.

As of December 31, 2013, we had spud 269 wells operated by the Company, 172 of which were on production and 261 of which will be horizontal wells. In 2013, we invested approximately $872 million in the Marcellus Shale and spud 108 operated wells, resulting in reserve additions and revisions of 1,297 Bcf. Of these 108 horizontal wells, 57 wells are located in our Price and Range Trust areas in Susquehanna County, 43 wells are located in our Greenzweig area in Bradford County, 6 wells are located in Lycoming County, and the remaining 2 wells are located in Sullivan County. In 2013, our operated horizontal wells had an average completed well cost of $7.0 million per well, average horizontal lateral length of 4,982 feet and an average of 18 fracture stimulation stages. This compares to an average completed operated well cost of $6.1 million per well, average horizontal lateral length of 4,070 feet and an average of 12 fracture stimulation stages in 2012. In 2011, our average completed operated well cost was $7.0 million per well with an average horizontal lateral length of 4,223 feet and an average of 14 fracture stimulation stages. Included in our total capital investments in the Marcellus Shale during 2013 was approximately $676 million for drilling and completions, $111 million for acquisition of properties, $9 million for seismic and $76 million in facilities, capitalized costs and other expenses. In 2012, we invested approximately $507 million in the Marcellus Shale and spud 92 operated wells, resulting in net reserve additions and revisions of 500 Bcf. In 2011, we invested approximately $332 million in the Marcellus Shale and spud 43 operated wells, resulting in net reserve additions and revisions of 327 Bcf.

Approximately 1,963 Bcf of our total proved net reserves at year-end 2013 were attributable to the Marcellus Shale. The Company had a total of 171 horizontal and one vertical well that the Company operated and that were on production as of December 31, 2013, resulting in net production from this area of 151 Bcf in 2013, compared to 54 Bcf in 2012 and 23 Bcf in 2011. Our 2013 year-end reserves booked in the Marcellus Shale include a total of 522 locations, of which 333 were proved developed producing, and 189 were proved undeveloped. At year-end 2012, we had approximately 816 Bcf in proved reserves in the Marcellus Shale from a total of 203 locations, of which 129 were proved developed producing, 1 was proved developed non-producing and 73 were proved undeveloped. At year-end 2011, we had approximately 342 Bcf of proved reserves in the Marcellus Shale from a total of 60 locations, of which 30 were proved developed producing, 2 were proved developed non-producing and 28 were proved undeveloped. The average gross proved reserves for the undeveloped wells included in our year-end reserves for 2013 was approximately 6.9 Bcf per well, compared to 7.6 Bcf per well at year-end 2012 and 7.5 Bcf per well in 2011.

In 2014, we plan to invest approximately $760 million in the Marcellus Shale and expect to participate in a total of 80 to 85 gross wells in 2014, the vast majority of which will be operated by us. In 2014, we estimate our net production from the Marcellus Shale will be in the range of 244 to 249 Bcf. Our ability to bring our Marcellus Shale production to market will depend on a number of factors including the construction of and/or the availability of capacity on gathering systems and pipelines that we do not own. We refer you to "Midstream Services — Gas Marketing" for a discussion of our gathering and transportation arrangements for the Marcellus Shale production and to the risk factor "Our ability to sell our natural gas and oil and to receive market prices for our production may be adversely affected by constraints or interruptions on gathering systems, pipelines, processing and transportation systems owned or operated by us or others." in Item 1A of Part I of this Form 10-K.

We believe that our Marcellus Shale acreage has significant development potential. Our drilling program with respect to the Marcellus Shale is flexible and will be impacted by a number of factors, including the results of our horizontal drilling efforts, our ability to determine the most effective and economic fracture stimulation methods, transportation capacity and well spacing and the natural gas commodity price environment. As we continue to gather data about the Marcellus Shale, it is possible that additional information may cause us to alter our drilling schedule or determine that prospects in some portion of our acreage position should not be pursued at all. We refer you to the risk factor "Our drilling plans for the Fayetteville Shale and the Marcellus Shale are subject to change" in Item 1A of Part I of this Form 10-K.

Ark-La-Tex

Our Ark-La-Tex division includes our conventional assets in the Arkoma Basin in Arkansas and Oklahoma and our conventional and unconventional assets in East Texas. Production from these assets was 18 Bcfe in 2013, compared to 26 Bcfe in 2012 and 40 Bcfe in 2011. The decline in production from these areas during 2013 and 2012 was primarily driven by asset dispositions as well as natural field production declines and lower capital investments in these areas since 2009. In May 2012, we sold our oil and natural gas leases, wells and gathering equipment in approximately 19,800 net acres in the Overton Field in East Texas for approximately $164 million. We expect our planned level of capital investments and the natural production decline in existing wells to decrease our net production from the Ark-La-Tex division in 2014. In 2013, we invested approximately $7 million in our Ark-La-Tex division and added new reserves of 0.2 Bcfe. Total proved net reserves from these areas were approximately 215 Bcfe as of December 31, 2013, compared to 213 Bcfe at year-end 2012 and 447 Bcfe at year-end 2011. In 2014, we expect to invest approximately $7 million in our Ark-La-Tex division.

New Ventures

We actively seek to find and develop new oil and natural gas plays with significant exploration and exploitation potential, which we refer to as "New Ventures." We have been focusing on both oil and natural gas unconventional plays, and the technological methods best suited to developing these plays, such as horizontal drilling and fracture stimulation techniques. New Ventures prospects are evaluated based on multi-well potential and land availability as well as other criteria and may be located both inside and outside of the United States. As of December 31, 2013, we held 3,972,732 net undeveloped acres in connection with our New Ventures prospects, of which 2,518,518 net acres were located in New

Brunswick, Canada. This compares to 3,819,128 net undeveloped acres held at year-end 2012 and 3,600,314 net undeveloped acres held at year-end 2011.

Although we believe that our New Ventures projects have significant exploration and exploitation potential, there can be no assurance that any prospects will result in viable projects or that we will not abandon our initial investments. We refer you to the risk factors "The success of our New Ventures projects is subject to drilling and completion technique risks and enhanced recovery methods. Our drilling results may not meet our expectations for reserves or production and the value of our undeveloped New Venture acreage could decline," and "Our exploration, development and drilling efforts and our operation of our wells may not be profitable or achieve our targeted returns" in Item 1A of Part I of this Form 10-K.

*Lower Smackover Brown Dense.* In July 2011, we announced that we would begin testing a new unconventional liquids rich play targeting the Lower Smackover Brown Dense formation, an unconventional reservoir that ranges in vertical depths from 8,000 to 11,000 feet and appears to be laterally extensive over a large area ranging in thickness from 300 to 550 feet. As of December 31, 2013, we held approximately 459,321 net undeveloped acres in the area, obtained at an average cost of $483 per acre. Our leases currently have an approximate 81% average net revenue interest and an average primary lease term of approximately three years, which may be extended for approximately three to four additional years.

As of December 31, 2013, we had drilled 11 operated wells in the play area, 5 of which were currently testing or producing, 1 is waiting on completion and 1 is drilling. We are continuing to analyze our results to date.

*New Brunswick, Canada*. In March 2010, we successfully bid for exclusive licenses from the Department of Natural Resources of New Brunswick to search and conduct an exploration program covering 2,518,518 net acres in the province in order to test new hydrocarbon basins. As a condition under our licenses, we are required to make investments of approximately $47 million Canadian dollars in the province by March 31, 2015 (March 31, 2013 prior to extension). In December 2012, we received two one-year extensions to our exploration license agreements which expire on March 16, 2014 and March 16, 2015, respectively. In December 2013, we completed our seismic program which was started in 2010 and included airborne gravity and magnetic surveys, surface geochemistry surveys, and the acquisition of 617 kilometers of 2-D seismic data. Through December 31, 2013, we have invested approximately $39.2 million Canadian dollars, or $36.9 million USD, in our New Brunswick exploration program towards our commitment. This is our first venture outside of the United States.

*Denver-Julesburg Basin*. We have approximately 302,243 net acres in the Denver-Julesburg Basin in eastern Colorado where we have begun testing an unconventional oil play targeting middle and late Pennsylvanian to Permian-age carbonates and shales. We have drilled two test wells to test multiple intervals and will continue to test the concept with additional wells in early 2014.

*Other*. In 2013, we drilled an operated horizontal well and re-entered an existing well to test the Bakken, the Three Forks and the Nisku objectives in Sheridan County, Montana. Our results were not commercial and we have discontinued our operations in the area. In 2013, we acquired undeveloped acreage and drilled a horizontal well in the Paradox Basin in Utah which tested the Cane Creek, Gothic and Hovenweep formations that was a dry hole. As of December 31, 2013, excluding acreage located in our New Brunswick, Lower Smackover Brown Dense, and Denver-Julesburg Basin prospects, our New Ventures operations held acreage totaling 692,650 net acres in other prospective areas located throughout multiple geographic regions.

Acquisitions and Divestitures

In April 2013, we acquired approximately 162,000 net acres in the Marcellus Shale for approximately $93 million. The acquired acreage is near our existing acreage in the Marcellus Shale.

In May 2012, we sold certain oil and natural gas leases, wells and gathering equipment in the Overton Field in East Texas for approximately $164 million. The sale included approximately 19,800 net acres in Smith County, Texas. Net production from the field was approximately 24 MMcfe per day as of the closing date and proved net reserves were approximately 143 Bcfe as of year-end 2011.

Capital Investments

During 2013, we invested a total of approximately $2.1 billion in our E&P business and participated in drilling 653 wells, 340 of which were successful and 309 of which were in progress at year-end. Of the 309 wells in progress at year-end, 227 and 77 were located in our Fayetteville Shale and the Marcellus Shale operating areas, respectively. Of the approximately $2.1 billion invested in our E&P business in 2013, approximately $907 million was invested in the Fayetteville Shale, $872 million in the Marcellus Shale, $3 million in East Texas, $4 million in our conventional Arkoma Basin program and $191 million in New Ventures projects, which includes $84 million in the Lower Smackover Brown Dense.

Of the $2.1 billion invested in 2013, approximately $1.5 billion was invested in exploratory and development drilling and workovers, $224 million in capitalized interest and other expenses, $159 million for acquisition of properties, and $28 million for seismic expenditures. Additionally, we invested approximately $76 million in our drilling rigs and related equipment, sand facility and other equipment, and $18 million in pond and water facilities. In 2012, we invested approximately $1.9 billion in our primary E&P business activities and participated in drilling 595 wells. Of the $1.9 billion invested in 2012, approximately $1.4 billion was invested in exploratory and development drilling and workovers, $186 million for acquisition of properties, $10 million for seismic expenditures and $254 million in capitalized interest and other expenses. Additionally, we invested approximately $15 million in our drilling rigs and related equipment, sand facility and other equipment. In 2011, we invested approximately $2.0 billion in our primary E&P business activities and participated in drilling 708 wells. Of the $2.0 billion invested in 2011, approximately $1.5 billion was invested in exploratory and development drilling and workovers, $227 million for acquisition of properties, $30 million for seismic expenditures and $199 million in capitalized interest and expenses and other technology-related expenditures. Additionally, we invested approximately $21 million in our drilling rig related equipment, sand facility and other equipment.

In 2014, we plan to invest approximately $2.0 billion in our E&P program and participate in drilling 563 to 578 gross wells, the vast majority of which will be operated by us. The Fayetteville Shale and the Marcellus Shale will be the primary focus of our capital investments, with planned investments of approximately $900 and $760 million, respectively. Our planned 2014 capital investments also include approximately $190 million in unconventional exploration and New Ventures projects, $178 million for our Lower Smackover Brown Dense exploration program, and $7 million in our Ark-La-Tex division.

Of the $2.0 billion allocated to our 2014 E&P capital budget, approximately $1.6 billion currently is planned to be invested in development and exploratory drilling, $47 million in seismic and other geological and geophysical expenditures, $159 million in acquisition of properties and $278 million in capitalized interest and expenses as well as equipment, facilities and technology-related expenditures. The planned capital program for 2014 is flexible and can be modified. We will reevaluate our proposed investments as needed to take into account prevailing market conditions and, if natural gas prices change significantly in 2014, we could change our planned investments. We refer you to "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Capital Investments" for additional discussion of the factors that could impact our planned capital investments in 2014.

Sales, Delivery Commitments and Customers

*Sales.* Our daily natural gas equivalent production averaged 1,800 MMcfe in 2013, compared to 1,544 MMcfe in 2012 and 1,370 MMcfe in 2011. Total natural gas equivalent production was 657 Bcfe in 2013, up from 565 Bcfe in 2012 and 500 Bcfe in 2011. Our natural gas production was 656 Bcf in 2013, compared to 565 Bcf in 2012 and 499 Bcf in 2011. The increase in production in 2013 resulted primarily from a 97 Bcf increase in net production from our Marcellus Shale properties, a 1 Bcfe increase in net production from our New Ventures plays, and a 1 Bcf increase in net production from our Fayetteville Shale properties, which more than offset a combined 7 Bcfe decrease in net production from our East Texas and Arkoma Basin properties. The increase in production in 2012 resulted primarily from a 49 Bcf increase in production from the Fayetteville Shale and a 30 Bcf increase in our Marcellus Shale production, which more than offset a combined 14 Bcfe decrease in net production from our East Texas and Arkoma Basin properties. We produced 138,000 barrels of oil in 2013, compared to 83,000 barrels of oil in 2012 and 97,000 barrels of oil in 2011. Our oil production has increased between 2013 and 2012 primarily due to our exploration activities in the Lower Smackover Brown Dense. In 2013, we produced 50,000 barrels of natural gas liquids, compared to no barrels of natural gas liquids in 2012, as a result of our exploration activities in the Lower Smackover Brown Dense. For 2014, we are targeting total net natural gas and oil production of approximately 740 to 752 Bcfe, which represents a growth rate of approximately 14% over our 2013 production volumes, using midpoints.

Sales of natural gas and oil production are conducted under contracts that reflect current prices and are subject to seasonal price swings. We are unable to predict changes in the market demand and price for natural gas, including changes that may be induced by the effects of weather on demand for our production. We periodically enter into various hedging and other financial arrangements with respect to a portion of our projected natural gas and oil production to support certain desired levels of cash flow and to minimize the impact of price fluctuations. Our policies prohibit speculation with derivatives and limit swap agreements to counterparties with appropriate credit standings. As of December 31, 2013, we had New York Mercantile Exchange, or NYMEX, commodity price hedges in place on 382 Bcf, or approximately 51% of our targeted 2014 natural gas production. We intend to hedge additional future production volumes to the extent natural gas prices rise to levels that we believe will achieve certain desired levels of cash flow. We refer you to Item 7A of this Form 10-K, "Quantitative and Qualitative Disclosures about Market Risks," for further information regarding our hedge position as of December 31, 2013.

Including the effect of hedges, we realized an average wellhead price of $3.65 per Mcf for our natural gas production in 2013, compared to $3.44 per Mcf in 2012 and $4.18 per Mcf in 2011. Our hedging activities increased our average realized natural gas sales price by $0.48 per Mcf in 2013, $1.10 per Mcf in 2012 and $0.62 per Mcf in 2011. Our average oil price realized was $103.32 per barrel in 2013, compared to $101.54 per barrel in 2012 and $94.08 per barrel in 2011. None of our oil production was hedged during 2013, 2012 or 2011. Our oil production is not material.

During 2013, the average price received for our natural gas production, excluding the impact of hedges, was approximately $0.48 per Mcf lower than average NYMEX prices. Differences between NYMEX and price realized are due primarily to locational differences and transportation cost. Assuming a NYMEX commodity price for 2014 of $3.75 per Mcf of natural gas, we expect to receive an average sales price for our natural gas production $0.55 to $0.60 per Mcf below the NYMEX Henry Hub average settlement price, excluding the impact of hedges, which includes average third-party transportation charges in the range of $0.35 to $0.40 per Mcf and average fuel charges in the range of .50% to 1.0% of our sales price for natural gas and basis differential. As of December 31, 2013, we have attempted to mitigate the volatility of basis differentials by protecting basis on approximately 242.0 Bcf of our 2014 expected natural gas production through financial hedging activities and physical sales arrangements at a basis differential to NYMEX natural gas prices of approximately ($0.09) per Mcf.

*Delivery Commitments*. As of December 31, 2013, we had natural gas delivery commitments of 393 Bcf in 2014 and 81 Bcf in 2015 under existing agreements. These commitments require the delivery of natural gas in Arkansas, Pennsylvania and Texas. These amounts are well below our forecasted 2014 natural gas production of approximately 723 to 733 Bcf from our Fayetteville Shale and the Marcellus Shale and anticipated 2015 production from our available reserves in our Fayetteville Shale, Marcellus Shale and Ark-La-Tex operations, which are not subject to any priorities or curtailments that may affect quantities delivered to our customers or any priority allocations or price limitations imposed by federal or state regulatory agencies, or any other factors beyond our control that may affect our ability to meet our contractual obligations other than those discussed in Item 1A. "Risk Factors." We expect to be able to fulfill all of our short-term or long-term contractual obligations to provide natural gas from our own production of available reserves; however, if we are unable to do so, we may have to purchase natural gas at market to fulfill our obligations.

*Customers*. Our customers include major energy companies, utilities and industrial purchasers of natural gas. During the years ended December 31, 2013, 2012 and 2011, no single third-party purchaser accounted for 10% or more of our consolidated revenues.

## Competition

All phases of the oil and natural gas industry are highly competitive. We compete in the acquisition of properties, the search for and development of reserves, the production and sale of natural gas and oil and the securing of labor and equipment required to conduct our operations. Our competitors include major oil and natural gas companies, other independent oil and natural gas companies and individual producers and operators. Many of these competitors have financial and other resources that substantially exceed those available to us.

Competition in Arkansas has increased in recent years due largely to the development of improved access to interstate pipelines and our discovery of the Fayetteville Shale. Although improved intrastate and interstate pipeline transportation in Arkansas has increased our access to markets for our natural gas production, these markets are also served by a number of other suppliers. Consequently, we will encounter competition that may affect both the price we receive and contract terms we must offer. Outside Arkansas, we are less established and face competition from a larger number of other producers. We also face competition for pipeline and other services to transport our product in to market, particularly in the Northeastern United States.

We cannot predict whether and to what extent any market reforms initiated by the FERC or any new energy legislation will achieve the goal of increasing competition, lessening preferential treatment and enhancing transparency in markets in which our natural gas is sold. However, we do not believe that we will be disproportionately or regulatory affected as compared to other natural gas and oil producers and marketers by any action taken by the FERC or any other legislative body.

Regulation

The exploration and development natural gas and oil resources and the transportation and sale of production historically have been heavily regulated. For example, state governments regulate the location of wells and establish the minimum size for spacing units. Permits typically are required before drilling. State and local governments also zoning and land use regulations also may limit the locations for drilling and production. Similar regulations also can affect the location, construction and operation of gathering and other pipelines needed to transport production to market. In addition, various suppliers of goods and services may require licensing.

Currently in the United States, the price at which natural gas or oil may be sold is not regulated. Congress has imposed price regulation from time to time, and there can be no assurance that the current, less stringent regulatory approach will continue. The federal government prohibits the export of crude oil with limited exceptions and requires permits to export natural gas. Broader freedom to export could lead to higher prices. In addition, the Dodd-Frank Wall Street Reform and Consumer Protection Act and the rules that the Commodities Futures Trading Commission, the CFTC, and the SEC have issued under it regulate certain futures and options contracts in the major energy markets, including for natural gas and oil. These regulations require us to comply with margin requirements and with certain clearing and trade execution requirements in connection with our derivative activities.

The exploration and development of natural gas and oil is also subject to extensive environmental regulation. We refer you to “Other Items — Environmental Regulation” and the risk factor “We incur substantial costs to comply with government regulations, especially regulations relating to environmental protection, and could incur even greater costs in the future” in Item 1A of Part I of this Form 10-K for a discussion of the impact of environmental regulation on our business.

**Midstream Services**

We believe our Midstream Services segment is well-positioned to complement our E&P initiatives and to compete with other midstream providers for unaffiliated business. We generate revenue from gathering fees associated with the transportation of natural gas to market and through the marketing of natural gas. Our gathering assets support our E&P operations and are currently concentrated in the Fayetteville Shale in Arkansas and the Marcellus Shale in Pennsylvania.

Our operating income from this segment was $325 million on revenues of $3.3 billion in 2013, compared to $294 million on revenues of $2.4 billion in 2012 and $248 million on revenues of $2.9 billion in 2011. Revenues increased in 2013 primarily due to an increase in the prices received for volumes marketed and an increase in volumes marketed. Revenues decreased in 2012 from a decrease in the prices received for volumes marketed, which was partially offset by an increase in volumes marketed. Adjusted EBITDA generated by our Midstream Services segment was $376 million in 2013, compared to $339 million in 2012 and $285 million in 2011. The increases in 2013 and 2012 operating income and Adjusted EBITDA were primarily due to increased gathering revenues and margins, and increased marketing margins, partially offset by increased operating costs and expenses. We expect that the operating income and Adjusted EBITDA of our Midstream Services segment will be stable over the next few years as we continue to develop our Fayetteville Shale and Marcellus Shale acreage positions. Adjusted EBITDA is a non-GAAP measure. We refer you to “Business — Other Items — Reconciliation of Non-GAAP Measures” in Item 1 of Part I of this Form 10-K for a table that reconciles Adjusted EBITDA to net income (loss).

Gas Gathering

We engage in gas gathering activities through our gathering subsidiaries, DeSoto Gathering and Angelina Gathering. DeSoto Gathering engages in gathering activities in Arkansas primarily related to the development of our Fayetteville Shale asset. In 2013, we invested approximately $158 million related to these activities and had gathering revenues of $516 million, compared to $165 million invested and revenues of $474 million in 2012 and $161 million invested and revenues of $408 million in 2011.

DeSoto Gathering continues to expand its network of gathering lines and facilities throughout the Fayetteville Shale area. During 2013, DeSoto Gathering gathered approximately 790 Bcf of natural gas in the Fayetteville Shale area, including 62 Bcf of natural gas from third-party operated wells. During 2012, DeSoto Gathering gathered approximately 781 Bcf of natural gas volumes in the Fayetteville Shale area, including 56 Bcf of natural gas from third-party operated wells. In 2011, DeSoto Gathering gathered approximately 704 Bcf of natural gas volumes in the Fayetteville Shale area, including 57 Bcf of natural gas from third-party wells. The increase in volumes gathered over the past three years was primarily due to our growing production volumes from the Fayetteville Shale. At the end of 2013, DeSoto Gathering had approximately 1,947 miles of pipe from the individual wellheads to the transmission lines and compression equipment representing in aggregate approximately 558,155 horsepower had been installed at 62 central point gathering facilities in the field.

Angelina Gathering currently engages in gathering activities in Pennsylvania and in East Texas. Angelina Gathering is expanding its network of gathering lines and facilities throughout the Marcellus Shale area. During 2013, Angelina Gathering gathered approximately 110 Bcf of natural gas volumes in the Marcellus Shale, Louisiana and East Texas areas. During 2012, Angelina Gathering gathered approximately 65 Bcf of natural gas in the Marcellus Shale and East Texas areas. In 2011, Angelina Gathering gathered approximately 42 Bcf of natural gas in the Marcellus Shale and East Texas areas. The increase in volumes gathered over the past three years was primarily due to our growing production volumes from the Marcellus Shale. At year-end 2013, Angelina Gathering had approximately 90 miles of pipe in Pennsylvania, 25 miles of pipe in Texas and 9 miles of pipe in Louisiana. As of December 31, 2013, compression equipment representing in aggregate approximately 44,755 horsepower had also been installed at 5 central point gathering facilities in Pennsylvania.

Gas Marketing

Our gas marketing subsidiary, SES, allows us to capture downstream opportunities related to marketing and transportation of natural gas. Our current marketing operations primarily relate to the marketing of our own natural gas production and some third-party natural gas. SES also purchases natural gas and sells it to end-users, manages basis risk and marketing portfolio and acquires transportation rights on third-party pipelines. During 2013, we marketed 800 Bcf of natural gas, compared to 676 Bcf in 2012 and 611 Bcf in 2011. Of the total volumes marketed, production from our affiliated E&P operations accounted for 96% in 2013, compared to 95% in 2012 and 94% in 2011.

SES is a “foundation shipper” on two pipeline projects serving the Fayetteville Shale. The Fayetteville Express Pipeline LLC, or FEP, is a 2.0 Bcf per day pipeline that is jointly owned by Kinder Morgan Energy Partners, L.P. and Energy Transfer Partners, L.P. FEP was placed in service in January 2011. SES has a maximum aggregate commitment of 1,200,000 Dekatherms per day for an initial term of ten years from the in-service date. Texas Gas Transmission, LLC or Texas Gas, a subsidiary of Boardwalk Pipeline Partners, LP, constructed two pipeline laterals called the Fayetteville and Greenville Laterals, which also provide transportation for our Fayetteville Shale gas. SES has maximum aggregate commitments of 800,000 MMBtu per day on the Fayetteville Lateral and 640,000 MMBtu per day on the Greenville Lateral.

The Fayetteville and the Greenville Laterals and the FEP allow us to transport our natural gas to interconnecting pipelines that offer connectivity and marketing options to the eastern half of the United States. These interconnecting pipelines include Centerpoint, Natural Gas Pipeline, Mississippi River Transmission, Gulf South, Texas Gas, Tennessee Gas Pipeline, Trunkline, ANR, Columbia Gulf, Texas Eastern, and Sonat. We rely in part upon the Fayetteville and Greenville Laterals and the FEP to service our production from the Fayetteville Shale.

During 2011 and 2012, SES entered into a number of short- and long-term firm transportation service agreements in support of our growing Marcellus Shale operations in Pennsylvania. In March 2011, SES entered into a precedent agreement with Millennium Pipeline Company, L.L.C. pursuant to which it will enter into short- and long-term firm natural gas transportation services on Millennium’s existing system. Expansions of the system were placed in-service in the second quarter of 2013. Further expansions are expected to be in-service by the second quarter of 2014. In June 2011, SEPCO entered into separate 15-year agreements with each of Bluestone Pipeline Company of Pennsylvania, LLC (“Bluestone Gathering”), and Susquehanna Gathering Company I, LLC, both wholly owned subsidiaries of DTE Pipeline Company, an affiliate of DTE Energy Company. Bluestone Gathering committed to build and operate a natural gas gathering system in Susquehanna County, Pennsylvania and Broome County, New York, and provide gathering services to SEPCO in support of a portion of our future Marcellus Shale natural gas production. This gathering system was initially placed into service in November 2012 and was completed in May 2013. Susquehanna Gathering Company I, LLC committed to build and operate gathering infrastructure from well pad receipt locations for deliveries into the Bluestone Gathering system as well as other potential field delivery points. This system was first placed into service November 2012 and will be constructed as necessary to support the company’s activities primarily in Susquehanna County.

SES also has executed firm transportation agreements with Tennessee Gas Pipeline Company (“TGP”), a subsidiary of Kinder Morgan Energy Partners, L.P., that increase our ability to move our Marcellus Shale natural gas production in the short term to market as well as a precedent agreement for an expansion project that was placed in-service in November 2013 pursuant to which SES has subscribed for 100,000 Dekatherms per day of capacity. TGP’s expansion project will expand its 300 Line in Pennsylvania to provide natural gas transportation from the Marcellus Shale supply area to existing delivery points on the TGP system. In March 2012, SES entered into a precedent agreement with Constitution Pipeline Co. LLC for a proposed 121-mile pipeline connecting to the Iroquois Gas Transmission and Tennessee Gas Pipeline systems in Schoharie County, New York. Subject to the receipt of regulatory approvals and satisfaction of other conditions, SES agreed to enter a 15-year firm transportation agreement with a total capacity of 150 MMcf per day on this project. Constitution Pipeline Co. LLC has extended the range for the pipeline's target in-service date to late 2015 through 2016 as a result of a longer than expected regulatory and permitting process. We have provided certain guarantees of a portion of SES's obligations under these agreements. We refer you to the risk factor "If our Fayetteville Shale and Marcellus Shale drilling programs fail to produce our projected supply of natural gas, our investments in our gathering operations could be lost. In addition, our commitments for transportation on third-party pipelines and gathering systems could make the sale of our natural gas uneconomic, which could have an adverse effect on our results of operations financial condition and cash flows.

In May 2013, SES entered into a precedent agreement with Columbia Gas Transmission, LLC for a project that will expand their existing system from Chester County, Pennsylvania to various interconnects throughout Pennsylvania, New Jersey, Maryland, and Virginia. SES's volume is 72,000 MMcf per day and is expected to be in service by the third quarter of 2015.

As of December 31, 2013, the Company's obligations for demand and similar charges under the firm transportation agreements and gathering agreements totaled approximately $3.5 billion and the Company has guarantee obligations of up to $100 million of that amount.

Competition

Our gas gathering and marketing activities compete with numerous other companies offering the same services, many of which possess larger financial and other resources than we have. Some of these competitors are other producers and affiliates of companies with extensive pipeline systems that are used for transportation from producers to end-users. Other factors affecting competition are the cost and availability of alternative fuels, the level of consumer demand and the cost of and proximity to pipelines and other transportation facilities. We believe that our ability to compete effectively within the marketing segment in the future depends upon establishing and maintaining strong relationships with producers and end-users.

Regulation

The transportation and sale of natural gas and oil are heavily regulated. Interstate pipelines must obtain authorization from the Federal Energy Regulatory Commission, or the FERC, to operate in interstate commerce, and state governments typically must authorize the construction of pipelines for intrastate service. The FERC currently allows interstate pipelines to adopt market-based rates; however, in the past the FERC has regulated pipeline tariffs and could do so again in the future. State tariff regulations vary. Currently, all the Company's pipelines are intrastate.

State and local permitting, zoning and land use regulations can affect the location, construction and operation of gathering and other pipelines needed to transport production to market. In addition, various suppliers of goods and services to our midstream business may require licensing.

Currently in the United States, the price at which natural gas or oil may be sold is not regulated. Congress has imposed price regulation from time to time, and there can be no assurance that the current, less stringent regulatory approach will continue. The federal government prohibits the export of crude oil with limited exceptions and requires permits to export natural gas. Broader freedom to export could lead to higher prices. In addition, the Dodd-Frank Wall Street Reform and Consumer Protection Act and the rules that the Commodities Futures Trading Commission, the CFTC, and the SEC have issued under it regulate certain futures and options contracts in the major energy markets, including for natural gas and oil. These regulations require us to comply with margin requirements and with certain clearing and trade execution requirements in connection with our derivative activities.

The transportation of natural gas and oil is also subject to extensive environmental regulation. We refer you to "Other Items — Environmental Regulation" and the risk factor "We incur substantial costs to comply with government regulations, especially regulations relating to environmental protection, and could incur even greater costs in the future" in Item 1A of Part I of this Form 10-K for a discussion of the impact of environmental regulation on our business.

**Other**

In 2013, we started construction on a corporate office complex located in Spring, Texas on 26 acres of commercial land that we purchased in 2012. The Company financed the construction of this complex through a construction agreement and lease arrangement. We are currently obligated for the construction costs incurred, which approximated $38 million at December 31, 2013. Upon completion of construction, a lease term of approximately five years will commence.

Our other operations have primarily consisted of real estate development activities concentrated on tracts of land located in Arkansas. During 2012, we sold our office complex in Fayetteville, Arkansas and our interest in approximately 9.5 acres of real estate near the Fayetteville complex. In 2012, we also sold our office complex in Conway, Arkansas for approximately $32 million and subsequently leased back our Conway complex from the buyer for a 15-year term. There were no sales of commercial real estate in 2013 or 2011.

Our sand mining operations, in support of our E&P business, are subject to regulation by the Federal Mine Safety and Health Administration under the Federal Mine Safety and Health Act of 1977. Information concerning mine safety violations or other regulatory matters required by section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K (17 CFR 229.106) is included in Exhibit 95.1 to this Form 10-K.

**Other Items**

Reconciliation of Non-GAAP Measures

Adjusted EBITDA is defined as net income (loss) plus interest, income tax expense, non-cash impairment of natural gas and oil properties, (gain) loss on derivatives, net of settlements, and depreciation, depletion and amortization. We have included information concerning Adjusted EBITDA in this Form 10-K because it is used by certain investors as a measure of the ability of a company to service or incur indebtedness and because it is a financial measure commonly used in our industry. Adjusted EBITDA should not be considered in isolation or as a substitute for net income (loss), net cash provided by operating activities or other income or cash flow data prepared in accordance with GAAP, or as a measure of our profitability or liquidity. Adjusted EBITDA as defined above may not be comparable to similarly titled measures of other companies.

We believe that net income (loss) is the financial measure calculated and presented in accordance with GAAP that is most directly comparable to Adjusted EBITDA as defined. The following table reconciles Adjusted EBITDA, as defined, with net income (loss) for the years-ended December 31, 2013, 2012 and 2011:

| | E&P | Midstream Services | Other | Total |
|---|---|---|---|---|
| | | (in thousands) | | |
| **2013** | | | | |
| Net income (loss) | $ 508,548 | $ 196,072 | $ (1,117) | **$ 703,503** |
| Depreciation, depletion and amortization expense | 735,215 | 50,940 | 457 | **786,612** |
| Impairment of natural gas and oil properties | – | – | – | **–** |
| Gain on derivatives, net of settlement | (20,898) | (480) | (2) | **(21,380)** |
| Net interest expense | 30,244 | 10,619 | 731 | **41,594** |
| Provision for income taxes | 368,320 | 119,223 | (669) | **486,874** |
| Adjusted EBITDA | $ 1,621,429 | $ 376,374 | $ (600) | $ **1,997,203** |
| **2012** | | | | |
| Net income (loss) | $ (884,126) | $ 175,570 | $ 1,492 | **$ (707,064)** |
| Depreciation, depletion and amortization expense | 765,368 | 44,395 | 1,190 | **810,953** |
| Impairment of natural gas and oil properties | 1,939,734 | – | – | **1,939,734** |
| Loss on derivatives, net of settlement | 2,154 | – | – | **2,154** |
| Net interest expense | 20,315 | 14,341 | 1,001 | **35,657** |
| Provision for income taxes | (548,556) | 104,522 | 895 | **(443,139)** |
| Adjusted EBITDA | $ 1,294,889 | $ 338,828 | $ 4,578 | **$ 1,638,295** |
| **2011** | | | | |
| Net income | $ 493,726 | $ 142,591 | $ 1,452 | **$ 637,769** |
| Depreciation, depletion and amortization expense | 666,125 | 37,261 | 1,125 | **704,511** |
| Impairment of natural gas and oil properties | – | – | – | **–** |
| Gain on derivatives, net of settlement | (5,600) | – | – | **(5,600)** |
| Net interest expense | 9,026 | 15,049 | – | **24,075** |
| Provision for income taxes | 322,714 | 90,221 | 286 | **413,221** |
| Adjusted EBITDA | $ 1,485,991 | $ 285,122 | $ 2,863 | **$ 1,773,976** |

Environmental Regulation

*General.* Our operations are subject to environmental regulation in the jurisdictions in which we operate. These laws and regulations require permits for drilling wells and the maintenance of bonding requirements to drill or operate wells and also regulate the spacing and location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, the plugging and abandoning of wells and the prevention and cleanup of pollutants and other matters. We maintain insurance against costs of clean-up operations, but we are not fully insured against all such risks. Although future environmental obligations are not expected to have a material impact on the results of our operations or financial condition, there can be no assurance that future developments, such as increasingly stringent environmental laws or enforcement thereof, will not cause us to incur material environmental liabilities or costs.

Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal fines and penalties and the imposition of injunctive relief. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly waste handling, storage, transport, disposal or cleanup requirements could materially adversely affect our operations and financial position, as well as those in the natural gas and oil industry in general. Although we believe that we are in substantial compliance with applicable environmental laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on us, there can be no assurance that this will continue in the future.

*Certain U.S. Statutes.* CERCLA, also known as the "Superfund law," imposes liability, without regard to fault or the legality of the original conduct, on certain classes of persons that are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include the owner or operator of the disposal site or sites where the release occurred and companies that transported or disposed or arranged for the transport or disposal of the hazardous substances found at the site. Persons who are or were responsible for releases of hazardous substances under CERCLA may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

The Resource Conservation and Recovery Act, as amended, or RCRA, generally does not regulate wastes generated by the exploration and production of natural gas and oil. RCRA specifically excludes from the definition of hazardous waste "drilling fluids, produced waters and other wastes associated with the exploration, development or production of oil, natural gas or geothermal energy." However, legislation has been proposed in Congress from time to time that would reclassify certain natural gas and oil exploration and production wastes as "hazardous wastes," which would make the reclassified wastes subject to much more stringent handling, disposal and clean-up requirements. If such legislation were to be enacted, it could have a significant impact on our operating costs, as well as the natural gas and oil industry in general. Moreover, ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes and waste oils, may be regulated as hazardous waste.

The Clean Air Act, as amended, restricts emissions into the atmosphere. Various activities in our operations, such as drilling, pumping and the use of vehicles, can release matter subject to regulation. We must obtain permits, typically from local authorities, to conduct various activities. Federal and state governmental agencies are looking to the issues associated with methane and other emissions from oil and natural gas activities, and further regulation could increase our costs or restrict our ability to produce. Although methane emissions are not currently regulated at the federal level, we are required to report emissions of various greenhouse gases, including methane.

The Oil Pollution Act, as amended, or the OPA, and regulations thereunder impose a variety of requirements on "responsible parties" related to the prevention of oil spills and liability for damages resulting from such spills in United States' waters. A "responsible party" includes the owner or operator of an onshore facility, pipeline or vessel, or the lessee or permittee of the area in which an offshore facility is located. OPA assigns liability to each responsible party for oil cleanup costs and a variety of public and private damages. Although liability limits apply in some circumstances, a party cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct or resulted from violation of a federal safety, construction or operating regulation. If the party fails to report a spill or to cooperate fully in the cleanup, liability limits likewise do not apply. Few defenses exist to the liability imposed by OPA. OPA imposes ongoing requirements on a responsible party, including the preparation of oil spill response plans and proof of financial responsibility to cover environmental cleanup and restoration costs that could be incurred in connection with an oil spill. In 2013, oil accounted for less than 1% of the Company's total production.

We own or lease, and have in the past owned or leased, onshore properties that for many years have been used for or associated with the exploration and production of natural gas and oil. Although we have utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties owned or leased by us on or under other locations where such wastes have been taken for disposal. In addition, some of these properties have been operated by third parties whose treatment and disposal or release of wastes was not under our control. These properties and the wastes disposed on them may be subject to CERCLA, the Clean Water Act, RCRA and analogous state laws. Under such laws, we could be required to remove or remediate previously disposed wastes (including waste disposed of or released by prior owners or operators) or property contamination (including groundwater contamination by prior owners or operators), or to perform remedial plugging or closure operations to prevent future contamination.

The Federal Water Pollution Control Act, as amended, or the FWPCA, imposes restrictions and strict controls regarding the discharge of produced waters and other natural gas and oil waste into navigable waters. Permits must be obtained to discharge pollutants to waters and to conduct construction activities in waters and wetlands. The FWPCA and similar state laws provide for civil, criminal and administrative penalties for any unauthorized discharges of pollutants and unauthorized discharges of reportable quantities of oil and other hazardous substances. Many state discharge regulations and the Federal National Pollutant Discharge Elimination System general permits issued by the EPA prohibit the discharge of produced water and sand, drilling fluids, drill cuttings and certain other substances related to the natural gas and oil industry into coastal waters. Although the costs to comply with zero discharge mandates under federal or state law may be significant, the entire industry is expected to experience similar costs and we believe that these costs will not have a material adverse impact on our results of operations or financial position. The EPA has adopted regulations requiring certain natural gas and oil exploration and production facilities to obtain permits for storm water discharges. Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans.

*Canada.* Our activities in Canada have to date been limited to certain geological and geophysical activities that are not subject to extensive environmental regulation. If and when we begin exploration activities in New Brunswick, we will be subject to federal, provincial and local environmental regulations that we believe require compliance efforts comparable to those required in the United States.

*Hydraulic Fracturing.* We utilize hydraulic fracturing in drilling wells as a means of maximizing their productivity. It is an essential and common practice in the oil and gas industry used to stimulate production of oil, natural gas, and associated liquids from dense and deep rock formations. The knowledge and expertise in fracturing techniques we have developed through our operations in the Fayetteville Shale and the Marcellus Shale are being utilized in our other operating areas, including our Lower Smackover Brown Dense acreage and, in the future, may include our exploration program in New Brunswick, Canada. Successful hydraulic fracturing techniques are also expected to be critical to the development of other New Venture areas. Hydraulic fracturing involves using water, sand, and certain chemicals to fracture the hydrocarbon-bearing rock formation to allow the flow of hydrocarbons into the wellbore. In our Fayetteville Shale and Marcellus Shale plays, the fracturing fluids we use are comprised of approximately 99.9% water and sand on a percentage volume basis. The remaining 0.1% is comprised of small quantities of additives which contain chemical compounds such as hydrochloric acid, phosphoric acid, glutaraldehyde and sodium chloride.

In the past few years, there has been an increased focus on environmental aspects of hydraulic fracturing practice, both in the United States and abroad. In the United States, hydraulic fracturing is typically regulated by state oil and natural gas commissions, but there have recently been a number of regulatory initiatives at the federal and local levels as well as by other state agencies. New York State currently has a moratorium on hydraulic fracturing, and some local governments also ban this procedure. We currently do not have material properties in these areas.

The Environmental Protection Agency, or EPA, has asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel under the Safe Drinking Water Act and released guidance documents on February 11, 2014 related to this newly asserted regulatory authority. In addition, the EPA issued final rules effective as of October 15, 2012 that subject oil and gas operations (production, processing, transmission, storage and distribution) to regulation under the New Source Performance Standards, or NSPS, and National Emission Standards for Hazardous Air Pollutants, or NESHAPS programs. The EPA final rules also include NSPS standards for completions of hydraulically fractured gas wells. These standards include the reduced emission completion, or REC techniques developed in the EPA's Natural Gas STAR program. The standards would be applicable to newly drilled and fractured wells as well as existing wells that are refractured. Further, the final regulations under NESHAPS include maximum achievable control technology, or MACT, standards for those glycol dehydrators and storage vessels at major sources of hazardous air pollutants not currently subject to MACT standards. Based on our current operations and practices, management believes, such newly promulgated rules will not have a material adverse impact on our financial position, results of operations or cash flows but these matters are subject to inherent uncertainties and management’s view may change in the future.

In October 2011, the EPA also announced a schedule for development of standards for disposal of wastewater produced from shale gas operations to publicly owned treatment works or POTWs. The regulations will be developed under the EPA's Effluent Guidelines Program under the authority of the Clean Water Act. The EPA anticipates issuing the proposed rules in 2014.

In addition to the EPA's efforts, legislation has been introduced before Congress, called the Fracturing Responsibility and Awareness of Chemicals Act, to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process. There are also certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. A number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, and although initial results were expected to be available by late 2012 and final results by 2014, to date the EPA has not released any results from the study. In addition, the U.S. Department of Energy is conducting an investigation into practices the agency could recommend to better protect the environment from drilling using hydraulic fracturing completion methods. The U.S. Department of the Interior also is considering disclosure requirements or other mandates for hydraulic fracturing on federal lands.

Some states in which we operate have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, public disclosure, waste disposal and well construction requirements on hydraulic fracturing operations or otherwise seek to ban fracturing activities altogether. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit the performance of well drilling in general and/or hydraulic fracturing in particular. In the event state, local, or municipal legal restrictions are adopted in areas where we are currently conducting, or in the future plan to conduct operations, we may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from the drilling and/or completion of wells.

In New Brunswick there presently are no hydraulic fracturing regulations. The provincial government has been working on a new comprehensive regulatory framework that it expects to release to the public in late 2014.

Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition, including litigation, to oil and gas production activities using hydraulic fracturing techniques. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of oil, natural gas, and associated liquids including from the development of shale plays, or could make it more difficult to perform hydraulic fracturing. The adoption of additional federal, state or local laws or the implementation of regulations regarding hydraulic fracturing could potentially cause a decrease in the completion of new oil and gas wells, increased compliance costs and time, which could adversely affect our financial position, results of operations and cash flows. We refer you to the risk factor "Our financial condition and results of operation could be adversely affected by legislative and regulatory initiatives in the United States and Canada relating to hydraulic fracturing that could result in increased costs and additional operating restrictions or delays or prevent us from realizing the value of undeveloped acreage" in Item 1A of Part I of this Form 10-K.

Employees

As of December 31, 2013, we had 2,621 total employees. None of our employees were covered by a collective bargaining agreement at year-end 2013. We believe that our relationships with our employees are good. In 2013, we were named a Top Workplace by the Houston Chronicle for the fourth consecutive year.

## GLOSSARY OF CERTAIN INDUSTRY TERMS

The definitions set forth below apply to the indicated terms as used in this Form 10-K. All natural gas reserves and production reported in this Form 10-K are stated at the legal pressure base of the state or area where the reserves exist and at 60 degrees Fahrenheit. All currency amounts are in U.S. dollars unless specified otherwise.

"Acquisition of properties" Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties. For additional information, see the SEC's definition in Rule 4-10(a) (1) of Regulation S-X, a link for which is available at the SEC's website, http://www.sec.gov/divisions/corpfin/ecfrlinks.shtml.

"Adjusted EBITDA" Net income (loss) plus interest, taxes, depreciation, depletion and amortization and any non-cash impairment of natural gas and oil properties or (gain) loss on derivatives, net of settlement. We refer you to "Business — Other Items — Reconciliation of Non-GAAP Measures" in Item 1 of Part I of this Form 10-K for a table that reconciles Adjusted EBITDA with our net income (loss) from our audited financial statements.

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

- (i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);
- (ii) Same environment of deposition;
- (iii) Similar geological structure; and
- (iv) Same drive mechanism.

For additional information, see the SEC's definition in Rule 4-10(a) (2) of Regulation S-X, a link for which is available at the SEC's website, http://www.sec.gov/divisions/corpfin/ecfrlinks.shtml.

"Available reserves" Estimates of the amounts of oil and natural gas which the registrant can produce from current proved developed reserves using presently installed equipment under existing economic and operating conditions and an estimate of amounts that others can deliver to the registrant under long-term contracts or agreements on a per-day, per-month, or per-year basis. For additional information, see the SEC's definition in Item 1207(d) of Regulation S-K, a link for which is available at the SEC's website, http://www.sec.gov/divisions/corpfin/ecfrlinks.shtml.

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

"Bcf" One billion cubic feet of natural gas.

"Bcfe" One billion cubic feet of natural gas equivalent. Determined using the ratio of one barrel of oil to six Mcf of natural gas.

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

"Dekatherm" One million British thermal units (Btus).

"Deterministic estimate" The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure. For additional information, see the SEC's definition in Rule 4-10(a) (5) of Regulation S-X, a link for which is available at the SEC's website, http://www.sec.gov/divisions/corpfin/ecfrlinks.shtml.

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

- (i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and
- (ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

For additional information, see the SEC's definition in Rule 4-10(a) (6) of Regulation S-X, a link for which is available at the SEC's website, http://www.sec.gov/divisions/corpfin/ecfrlinks.shtml.

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

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

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

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

(iv) Provide improved recovery systems.

For additional information, see the SEC's definition in Rule 4-10(a) (7) of Regulation S-X, a link for which is available at the SEC's website, http://www.sec.gov/divisions/corpfin/ecfrlinks.shtml.

"Development project" A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project. For additional information, see the SEC's definition in Rule 4-10(a) (8) of Regulation S-X, a link for which is available at the SEC's website, http://www.sec.gov/divisions/corpfin/ecfrlinks.shtml.

"Development well" A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive. For additional information, see the SEC's definition in Rule 4-10(a) (9) of Regulation S-X, a link for which is available at the SEC's website, http://www.sec.gov/divisions/corpfin/ecfrlinks.shtml.

"Downspacing" The process of drilling additional wells within a defined producing area to increase recovery of natural gas and oil from a known reservoir.

"E&P" Exploration for and production of natural gas and oil.

"Economically producible" The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities. For additional information, see the SEC's definition in Rule 4-10(a) (10) of Regulation S-X, a link for which is available at the SEC's website, http://www.sec.gov/divisions/corpfin/ecfrlinks.shtml.

"Estimated ultimate recovery (EUR)" Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date. For additional information, see the SEC's definition in Rule 4-10(a) (11) of Regulation S-X, a link for which is available at the SEC's website, http://www.sec.gov/divisions/corpfin/ecfrlinks.shtml.

"Exploitation" The development of a reservoir to extract its gas and/or oil.

"Exploratory well" An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section. For additional information, see the SEC's definition in Rule 4-10(a) (13) of Regulation S-X, a link for which is available at the SEC's website, http://www.sec.gov/divisions/corpfin/ecfrlinks.shtml.

"Field" An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious, strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms *structural feature* and *stratigraphic condition* are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc. For additional information, see the

SEC’s definition in Rule 4-10(a) (15) of Regulation S-X, a link for which is available at the SEC’s website, http://www.sec.gov/divisions/corpfin/ecfrlinks.shtml.

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

“Gross well or acre” A well or acre in which the registrant owns a working interest. The number of gross wells is the total number of wells in which the registrant owns a working interest. For additional information, see the SEC's definition in Item 1208(c)(1) of Regulation S-K, a link for which is available at the SEC's website, http://www.sec.gov/divisions/corpfin/ecfrlinks.shtml.

“Gross working interest” Gross working interest is the working interest in a given property plus the proportionate share of any royalty interest, including overriding royalty interest, associated with the working interest.

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

“MBbls” One thousand barrels of oil or other liquid hydrocarbons.

“Mcf” One thousand cubic feet of natural gas.

“Mcfe” One thousand cubic feet of natural gas equivalent, with liquids converted to an equivalent volume of natural gas using the ratio of one barrel of oil to six Mcf of natural gas.

“MMBbls” One million barrels of oil or other liquid hydrocarbons.

“MMBtu” One million British thermal units (Btus).

“MMcf” One million cubic feet of natural gas.

“MMcfe” One million cubic feet of natural gas equivalent, with liquids converted to an equivalent volume of natural gas using the ratio of one barrel of oil to six Mcf of natural gas.

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

“Net well” or “Net acre” The number of net wells or acres is the sum of the fractional working interests owned in individual wells or tracts. For additional information, see the SEC's definition in Item 1208(c)(2) of Regulation S-K, a link for which is available at the SEC's website, http://www.sec.gov/divisions/corpfin/ecfrlinks.shtml.

“NGL” Natural gas liquids.

“NYMEX” The New York Mercantile Exchange.

“Operating interest” An interest in natural gas and oil that is burdened with the cost of development and operation of the property.

“Overriding royalty interest” A fractional, undivided interest or right to production or revenues, free of costs, of a lessee with respect to an oil or natural gas well, that overrides a working interest.

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

“Present Value Index” or “PVI” A measure that is computed for projects by dividing the dollars invested into the PV-10 resulting or expecting to result from the investment by the dollars invested.

“Probabilistic estimate” The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence. For additional information, see the SEC's definition in Rule 4-10(a) (19) of Regulation S-X, a link for which is available at the SEC's website, http://www.sec.gov/divisions/corpfin/ecfrlinks.shtml.

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

"Productive wells" Producing wells and wells mechanically capable of production. For additional information, see the SEC's definition in Item 1208(c)(3) of Regulation S-K, a link for which is available at the SEC's website, http://www.sec.gov/divisions/corpfin/ecfrlinks.shtml.

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

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

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

"Proved oil and gas reserves" Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. Also referred to as "proved reserves." For additional information, see the SEC's definition in Rule 4-10(a) (22) of Regulation S-X, a link for which is available at the SEC's website, http://www.sec.gov/divisions/corpfin/ecfrlinks.shtml.

"Proved reserves" See "proved oil and gas reserves."

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

"PV-10" When used with respect to natural gas and oil reserves, PV-10 means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development costs, using prices and costs in effect as of the date of the report or estimate, without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expense or to depreciation, depletion and amortization, discounted using an annual discount rate of 10%. Also referred to as "present value." After-tax PV-10 is also referred to as "standardized measure" and is net of future income tax expense.

"Reserve life index" The quotient resulting from dividing total reserves by annual production and typically expressed in years.

"Reserve replacement ratio" The sum of the estimated net proved reserves added through discoveries, extensions, infill drilling and acquisitions (which may include or exclude reserve revisions of previous estimates) for a specified period of time divided by production for that same period of time.

"Reservoir" A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs. For additional information, see the SEC's definition in Rule 4-10(a) (27) of Regulation S-X, a link for which is available at the SEC's website, http://www.sec.gov/divisions/corpfin/ecfrlinks.shtml.

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

"Tcf" One trillion cubic feet of natural gas.

"Tcfe" One trillion cubic feet of natural gas equivalent, with liquids converted to an equivalent volume of natural gas using the ratio of one barrel of oil to six Mcf of natural gas.

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

"Undeveloped acreage" Those leased acres on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil or gas regardless of whether such acreage contains proved reserves. For additional information, see the SEC's definition in Item 1208(c)(4) of Regulation S-K, a link for which is available at the SEC's website, http://www.sec.gov/divisions/corpfin/ecfrlinks.shtml.

"Undeveloped oil and natural gas reserves" Undeveloped oil and natural gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Also referred to as "undeveloped reserves." For additional information, see the SEC's definition in Rule 4-10(a) (31) of Regulation S-X, a link for which is available at the SEC's website, http://www.sec.gov/divisions/corpfin/ecfrlinks.shtml.

"Undeveloped reserves" See "undeveloped oil and natural gas reserves."

"USD" United States Dollar.

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

"Working interest" An operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and to receive a share of production.

"Workovers" Operations on a producing well to restore or increase production.

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

## ITEM 1A. RISK FACTORS

In addition to the other information included in this Form 10-K, the following risk factors should be considered in evaluating our business and future prospects. The risk factors described below represent what we believe are the most significant risk factors with respect to us and our business. In assessing the risks relating to our business, investors should also read the other information included in this Form 10-K, including our financial statements and the related notes and "Management's Discussion and Analysis of Financial Condition and Results of Operation – Cautionary Statement about Forward-Looking Statements."

**Our revenues and the value of our assets are highly dependent on the prices for natural gas and, to a lesser extent, oil. These prices are volatile, and a substantial or extended decline in natural gas and oil prices would have a material adverse effect on us.**

Our financial results and the value of our assets correlate closely to the prices we can and do obtain for what we produce, in particular natural gas, which accounts for almost 100% of our production. Prices for natural gas and oil are highly volatile and unpredictable. The following factors, among others, affect the supply of and demand for natural gas and oil:

- Changes in consumption patterns, including those resulting from population changes and migrations, new technologies and grown in emerging markets
- Global and local economic conditions
- Inventory levels
- Ability and cost of transporting product to markets, including the ability to connect resources to pipelines or other means of transportation, bottlenecks in pipeline or other transportation capacity such as many are experiencing in the Marcellus and the Utica Shales, export and import controls and other constraints
- Production disruptions
- Actions of governments and multinational groups, such as the Organization of Petroleum Exporting Countries (OPEC)
- Currency exchange rates
- Competition from other producers and from other energy sources, including renewables, which affects the level of supply
- Technological developments
- Weather, earthquakes and other natural events
- Market perceptions of future prices, whether due to the foregoing factors or others

A significant or extended decline in natural gas and oil prices, such as the one from 2008 into 2012 when the NYMEX natural gas price dropped from $13.58 to $1.91 per MMBtu, would have a material adverse effect on our financial position, our results of operations, our access to capital and the quantities of natural gas and oil that we can produce economically, including the following:

- The cash flows from our operations would be reduced, decreasing funds available for capital investments employed to replace reserves or increase production.
- Lower prices would reduce the value of our natural gas and oil assets and, in some cases, make them no longer be economic to produce. This could result in impairments to the values of our assets, such as occurred in 2012.
- Access to other sources of capital, such as equity or debt markets, could be severely limited or unavailable.
- We could fail to meet financial or other covenants in the documentation governing our debt, leading to mandatory prepayments or defaults.
- Locational price differentials change, making it difficult to predict the best locations to conduct our activities.
- Varying perceptions of future prices can lead to difficulties in agreeing on the value of assets in acquisitions or dispositions.

We endeavor to mitigate against these risks through hedging a significant portion of our production. Hedging also presents risks, including our failure to project the appropriate volumes and price points for hedges and the creditworthiness of our counterparties. For a discussion of our hedging activities, we refer you to Note 5 to the consolidated financial statements included in this Form 10-K. Additionally, we mitigate these risks, in part, through our Midstream Services business, which generates cash flow that is largely fee-based and thus not directly impacted by commodity price volatility.

**Our ability to sell our natural gas and oil and/or to receive market prices for our production may be adversely affected by constraints or interruptions on gathering systems, pipelines, processing and transportation systems owned or operated by us or others.**

The marketability of our natural gas and oil production depends in part on the availability, proximity, and capacity of gathering systems, processing and pipeline and other transportation systems owned or operated by third parties. The lack of available capacity in these systems and facilities can result in shutting in producing wells, delaying or discontinuing the development plans for our properties or receiving lower prices. Although we have some contractual control over the transportation and gathering of our production, material changes in these business relationships could materially affect our operations. Federal and state regulation of natural gas and oil production, processing and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines, infrastructure or capacity constraints, and general economic conditions could adversely affect our ability to produce, gather, and transport natural gas. In particular, continued development of the Marcellus Shale by us and others could overtax the capacity of existing gathering and pipeline system, and new or expanded capacity may not be in place in time.

**The vast majority of our current operations and production are in two areas, the Fayetteville Shale and the Marcellus Shale, and significant events or circumstances affecting one or both of these areas could have a material and adverse effect on our operations in those areas and thus our overall performance.**

Production from the Fayetteville Shale and the Marcellus Shale accounted for 74% and 23%, respectively, of our consolidated production and, when considering both our E&P and Midstream Services business, essentially all of our operating income in 2013. Our current Fayetteville Shale operations are almost entirely in Arkansas, and our current Marcellus Shale operations currently are only in Pennsylvania. Significant events or circumstances of the types described elsewhere in these Risk Factors or otherwise that affect one or both of these areas would affect a very large part of our operations simultaneously and, if they do not affect the industry generally, would affect us disproportionately compared to other companies,. Those events and circumstances include changes in local laws and regulations, constraints on transportation, natural events, localized price changes and availability of water, skilled personnel, equipment, services and supplies, among others.

**If we fail to find or acquire additional reserves, our reserves and production will decline materially from their current levels.**

The rate of production from natural gas and oil properties generally declines as reserves are depleted. Unless we acquire additional properties containing proved reserves, conduct successful exploration and development activities, successfully apply new technologies or identify additional behind-pipe zones or secondary recovery reserves, our proved reserves will decline materially as reserves are produced. Future natural gas and oil production is, therefore, highly dependent upon our level of success in acquiring or finding additional reserves.

**Our business could be adversely affected by competition with other companies.**

The natural gas and oil industry is highly competitive, and our business could be adversely affected by companies that are in a better competitive position. As an independent natural gas and oil company, we frequently compete for reserve acquisitions, exploration leases, licenses and concessions, marketing agreements, transportation, equipment and labor against companies with financial and other resources substantially larger than those we possess. Many of our competitors may be able to pay more for exploratory prospects and productive natural gas and oil properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than we can. Our ability to explore for natural gas and oil prospects and to acquire additional properties in the future will depend on our ability to conduct operations, to evaluate and select suitable properties and to consummate transactions in this highly competitive environment. In addition, many of our competitors have been operating in some of our core areas for a much longer time than we have or have established strategic long-term positions in geographic regions in which we may seek new entry.

**Natural gas and oil exploration and production is an inherently risky business with many uncertainties and potential liabilities. The results of our activities may not be what we project, and not all our liabilities and other exposures may be covered by insurance.**

By its nature, exploring for and producing natural gas and oil involves substantial capital investment with no assurance of return, or returns at expected levels, and the risk of environmental and other liability. Among other things:

- Although we utilize sophisticated geological and geophysical tools to determine where to drill, these do not predict with certainty the presence of natural gas or oil or the rate at which they can be produced. Some wells will result in no production, production that does not cover costs or production at lower levels than expected.
- During drilling we can face difficulties in landing our wellbore in the desired zones, staying in the desired zones while drilling horizontally, penetrating rock formations, controlling well pressure, stimulating reservoirs through fracturing and cleaning the wellbore following fracturing and running casing the entire length of the wellbore. These circumstances can delay completion, increase costs and possibly lead to the abandonment of the particular location.
- When we acquire properties or businesses through acquisitions, including properties already producing, we may fail to assess correctly the potential of the properties, the costs of integration and development, matters affecting legal title and thus the right to drill and ownership of production, the liabilities that we assume as part of the acquisition and the risks associated with ownership, development and operation.
- Equipment can fail or not be available and pipelines can rupture.
- We can encounter well blowouts, cratering, explosions, pipeline failure, fires, brine or other fluids, drainage of production from neighboring properties and other hazards.
- Earthquakes and hurricanes, storms and other weather events can interfere with drilling activities and operations.
- Although we believe we maintain a robust health, safety and environmental program, incidents can occur, whether due to natural events, the actions of third parties or our own errors or oversights. Spills, injuries or other calamities can result in liability for our Company, damage to our properties and interruption of our operations.

We maintain insurance against many potential losses or liabilities arising from our operations in accordance with customary industry practices and in amounts that we believe to be prudent. Our insurance does not protect us against all operational risks; for example, we generally do not maintain business interruption insurance, and pollution and environmental risks generally are not fully insurable. These risks could give rise to significant costs not covered by insurance that could have a material adverse effect upon our financial results.

**Our business strategy depends on executing extensive drilling programs and controlling costs to improve our overall return. Shortages of oilfield equipment, services, supplies, raw materials and qualified personnel could adversely affect our ability to implement our programs or to achieve our desired levels of costs.**

We are engaged in large-scale programs to develop our assets, particularly in the Fayetteville Shale and the Marcellus Shale. We are achieving economies of scale through our sizeable operations in these two areas and, in some cases, vertical integration in certain oilfield services, such as drilling, sand mining and pressure control. We nonetheless compete with other companies for oilfield equipment, services, supplies, raw materials and qualified personnel. In particular, the demand for qualified and experienced field personnel to drill wells and conduct field operations and for geologists, geophysicists, engineers and other professionals in the natural gas and oil industry can fluctuate significantly, often in correlation with natural gas and oil prices, causing periodic shortages. These factors also cause significant increases in costs for equipment, services, personnel and raw materials (such as sand, cement, manufactured proppants and other materials utilized in the provision of the oilfield services). Higher natural gas and oil prices generally stimulate increased demand and result in increased costs for professional personnel, drilling rigs, crews and associated supplies, equipment, services and raw materials. In addition, our E&P operations also require local access to large quantities of water supplies and disposal services for produced water in connection with our hydraulic fracture stimulations due to prohibitive transportation costs. We cannot be certain when we will experience shortages or cost increases, which could adversely affect our profit margin, cash flow and operating results or restrict our ability to drill wells and conduct ordinary operations.

**Our announced drilling plans can change due to various factors.**

Our drilling plans are flexible and are dependent upon a number of factors, including the extent to which we can replicate the results of our most successful wells in addition to the natural gas and oil commodity price environment. The determination as to whether we continue to drill wells in our operating areas may depend on any one or more of the following factors:

- Our ability to determine the most effective and economic fracture stimulation
- Our ability to transport our production to the most favorable markets
- Material changes in natural gas prices (including location differentials)
- Changes in the costs to drill, complete or operate wells and our ability to reduce drilling risks
- The extent of our success in drilling and completing horizontal wells
- The costs and availability of oilfield personnel services and drilling supplies, raw materials, and equipment and services
- Success or failure of wells drilled in similar formations or which would use the same production facilities
- Receipt of additional seismic or other geologic data or reprocessing of existing data
- The extent to which we are able to effectively perform our vertically integrated services, including operating our own rigs, fracture stimulation fleet, sand plant, field services and supply chain management
- The failure or unwillingness of co-owners of working interests to pay for their share of the costs of new wells or operations
- Availability and cost of capital
- The impact of federal, state and local government regulation, including any increase in severance taxes

**Our ability to produce natural gas and oil could be impaired if we are unable to acquire adequate supplies of water for our drilling operations or are unable to dispose of the water we use at a reasonable cost and within applicable environmental rules.**

Our inability to locate sufficient amounts of water, or dispose of or recycle water used in our E&P operations, could adversely impact our operations. Moreover, the imposition of new environmental initiatives and regulations could include restrictions on our ability to conduct certain operations such as hydraulic fracturing or disposal of waste, including, but not limited to, produced water, drilling fluids and other wastes associated with the exploration, development or production of natural gas. Compliance with environmental regulations and permit requirements governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of wells may increase our operating costs and cause delays, interruptions or termination of our operations, the extent of which cannot be predicted, all of which could have an adverse effect on our operations and financial condition.

**Our financial condition and results of operation could be adversely affected by legislative and regulatory initiatives in the United States and elsewhere relating to environmental matters, particularly hydraulic fracturing and climate change, which could result in increased costs and additional operating restrictions or delays or prevent us from realizing the value of undeveloped acreage.**

As described more fully under “Other Items — Environmental Regulation,” our operations are subject to extensive environmental regulation. New regulations can increase costs or delay or prevent us from achieving our goals. In particular, we often utilize hydraulic fracturing in our drilling activities, and it forms a critical part of our cost structure and success. As also described there, various governmental and non-governmental groups are advocating restrictions and, in some instances, outright bans on the use of hydraulic fracturing.

Our E&P operations are currently focused on the production of hydrocarbons from unconventional sources, and we expect to continue to focus on such resources in the future. The production of hydrocarbons from these sources has an energy intensity that is a number of times higher than that for production from conventional sources. Therefore, we expect that the greenhouse gas intensity of our production will increase in the long-term. We actively seek to reduce the environmental impact of our operations by pursuing more efficient use of natural resources such as hydrocarbons and water and managing and mitigating the emissions to the air, water and soil, with a focus on the reduction of greenhouse gas emissions. With the efforts of our Health, Safety and Environmental Department, we have been able to plan for and comply with environmental initiatives without materially altering our operating strategy. We anticipate making increased expenditures of both a capital and expense nature as a result of the increasingly stringent laws relating to the protection of the environment that will increase the cost of equipment, materials and services whose production utilizes hydrocarbons.

We may also face increased competition from alternative energy sources that do not rely on hydrocarbons. We cannot predict with any reasonable degree of certainty our future exposure concerning such matters and if we are unable to find solutions to environmental initiatives as they arise, including reducing the greenhouse gas emissions for our existing projects, we may have additional costs as well as compliance and operational risks with respect to our existing operations as well as facing difficulties in pursuing new projects.

**Although our estimated natural gas and oil reserve data is independently audited, our estimates are only estimates and thus may prove to be inaccurate.**

As described in more detail under "Critical Accounting Policies and Estimates – Natural Gas and Oil Properties," our reserve data represents the estimates of our reservoir engineers made under the supervision of our management, and our reserve estimates are audited each year by Netherland, Sewell & Associates, Inc., or NSAI, an independent petroleum engineering firm. Natural gas and oil reserves cannot be measured exactly, however, and our estimates of natural gas and oil reserves requires extensive judgments of reservoir engineering data and projections of cost that will be incurred in developing and producing reserves, along with pricing. Recovery of undeveloped reserves generally requires significant capital investments and successful drilling operations. Actual reserves, costs and prices may differ dramatically from our estimates.

**Our operations can be impacted by events beyond our control, adversely affecting our cash flows and results of operations.**

A portion of our production in any region may be interrupted, or shut in, from time to time for numerous reasons, including as a result of weather conditions, earthquakes, accidents, loss of pipeline, gathering, processing or transportation system access or capacity, field labor issues or strikes or voluntarily curtailment in response to market conditions. Further, although we operate most of the wells in which we have interests, some are operated by third parties. Although we endeavor to assure that third parties conduct their activities with rigorous regard for health, safety, environment and cost, we do not control them and therefore cannot be sure they will operate to the same standards that we would. If a substantial amount of our production is interrupted at the same time, it could temporarily adversely affect our cash flows and results of operations. Counterparties to contracts, whether those providing us with goods or services or those owing us payments for production or services, may breach their obligations.

**We may have difficulty financing our planned capital investments, which could adversely affect our growth.**

We have experienced and expect to continue to experience substantial capital investment and working capital needs to implement our drilling program. Our planned capital investments for 2014 are expected to exceed the net cash generated by our operations under current natural gas prices. We expect to be able to borrow under our revolving credit facility to fund capital investments to the extent they exceed our net cash flow and cash on hand. Our ability to borrow under our revolving credit facility is subject to certain conditions. As of December 31, 2013, we would satisfy those conditions; however, if conditions were not satisfied and we were not otherwise able to borrow funds, we would need to curtail our drilling, development and other activities or be forced to sell some of our assets on a possibly unfavorable basis. Any such curtailment or sale could have a material adverse effect on our results and future operations.

**We have made significant investments in pipelines and gathering systems and contracts and in oilfield service businesses, including our drilling rig, pressure pumping equipment and sand mine operations, to lower costs and secure inputs for our operations and transportation for our production. If our exploration and production activities are curtailed or disrupted, we may not recover our investment in these activities, which could adversely impact our results of operations. In addition, our continued expansion of these operations may adversely impact our relationships with third-party providers.**

Through December 31, 2013, we had invested approximately $1,096 million in our gas gathering system built for the Fayetteville Shale and approximately $213 million in our gas gathering system built for the Marcellus Shale. To the extent necessary to gather our production, we may make further substantial investments in the expansion of our gas gathering systems. We have also entered into multiple firm transportation agreements relating to natural gas volumes produced from the Fayetteville Shale as well as a number of firm transportation and gathering agreements relating to the Marcellus Shale. As of December 31, 2013, our aggregate demand charge commitments under these firm transportation agreements and gathering agreements were approximately $3.5 billion. Our gas gathering business will largely rely on natural gas sourced from our operations. If our Fayetteville Shale and Marcellus Shale programs fail to produce significant quantities of natural gas within expected timeframes, our investments in our gas gathering operations could be lost, and we could be forced to pay demand or other charges for transportation on pipelines and gathering systems that we would not be using.

We also have made significant investments to meet certain of our oilfield services needs, including establishing our own drilling rig operation, sand mine and pressure pumping capability. If our level of operations is reduced, we may not be able to recover these investments. Further, entering into these service and supply sectors, including competing with them for qualified personnel and supplies, may have an adverse effect on our relationships with our existing third-party service and resource providers or our ability to secure these services and resources from other providers.

**If we fail to drill all of the wells that are necessary to hold our acreage, the lease terms could expire, which would result in the loss of certain leasehold rights.**

Leases on approximately 196,052 net acres of our Fayetteville Shale acreage will expire in the next three years if we do not drill successful wells to develop the acreage or otherwise take action to extend the leases. Approximately 117,407 net acres of our Marcellus Shale acreage will expire in the next three years if we do not drill successful wells to develop the acreage or otherwise take action to extend the leases. As discussed above under "Our drilling plans for the Fayetteville Shale and the Marcellus Shale are subject to change," our ability to drill wells depends on a number of factors, including certain factors that are beyond our control. With the exception of the Ozark Highlands Unit, which is federally leased, the current rules in Arkansas relating to the Fayetteville Shale provide that each drilling unit would consist of a governmental section of approximately 640 acres and operators are permitted to drill up to 16 wells per drilling unit for each unconventional source of supply. In Pennsylvania, the location of our Marcellus Shale acreage, there are currently no rules establishing requirements for drilling units. However, current rules in Arkansas may change and rules may be implemented in Pennsylvania that could impair our ability to drill or maintain our acreage position. In addition, other E&P operator drilling activity could impair our ability to drill and maintain acreage positions. To the extent that any field rules prevent us from successfully drilling wells in certain areas, we may not be able to drill the wells required to maintain our leasehold rights and our leasehold investments could be lost.

**We depend upon our management team and our operations require us to attract and retain experienced technical personnel.**

The successful implementation of our business strategy and handling of other issues integral to the fulfillment of our business strategy depends, in part, on our experienced management team, as well as certain key geoscientists, geologists, engineers and other professionals employed by us. The success of our technological initiatives that support our business enterprise is also dependent upon attracting and retaining experienced technical professionals. The loss of key members of our management team or other highly qualified technical professionals could have a material adverse effect on our business, financial condition and operating results.

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

The elimination of certain key U.S. federal income tax deductions currently available to oil and natural gas exploration and production companies has been proposed in recent years. These changes have included, among other proposals:

- Repeal of the percentage depletion allowance for oil and natural gas properties
- Elimination of current deductions for intangible drilling and development costs
- Elimination of the deduction for certain domestic production activities
- Extension of the amortization period for certain geological and geophysical expenditures

It is unclear whether these or similar changes will be enacted. The passage of these or any similar changes in federal income tax laws to eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development could have an adverse effect on our financial position, results of operations and cash flows.

**Cyber attacks or terrorist attacks could affect our assets, cash flows and results of operations.**

Cyber attacks on businesses are occurring with greater frequency, and natural gas and oil infrastructure and systems could become targets of terrorists. We rely on electronic systems and networks to control and manage our exploration and production, pipeline and marketing operations and have multiple layers of security to mitigate risks of cyber attack. We also have security in place around our physical operations. If we nonetheless were to experience an attack and our security measures failed, the potential consequences to our businesses and the communities in which they operate could be significant.

**Our certificate of incorporation and, bylaws contain provisions that could make it more difficult for someone to either acquire us or affect a change of control.**

Certain provisions of our certificate of incorporation and bylaws, together with any stockholder rights plan that we might have in place, could discourage an effort to acquire all or a controlling interest in the Company or replace directors or members of our executive management team. These provisions could potentially deprive our stockholders of opportunities to sell shares of our common stock at above-market prices.

**Our Canadian exploration and production activities are subject to different risks and uncertainties, different from or in addition to those we face in our U.S. operations.**

In addition to the various risks associated with our U.S. operations, we are subject to risks and uncertainties related to our Canadian exploration and production activities, including risks related to increases in taxes and governmental royalties, changes in laws and policies governing operations of foreign-based companies, restrictions on imports and exports, expropriation of property, cancellation of contract rights, environmental protection controls, environmental compliance requirements and laws pertaining to workers' health and safety. Consequently, our exploration, development and production activities in Canada could be substantially affected by factors beyond our control. In addition, the rights of aboriginal peoples, called First Nations in Canada, are not clear. Our operations in New Brunswick have been subject to local protests, causing several temporary interruptions to our exploration activities.

## ITEM 1B. UNRESOLVED STAFF COMMENTS.

None.

## ITEM 2. PROPERTIES

The summary of our oil and natural gas reserves as of fiscal year-end 2013 based on average fiscal-year prices, as required by Item 1202 of Regulation S-K, is included in the table headed "2013 Proved Reserves by Category and Summary Operating Data" in "Business – Exploration and Production – Our Proved Reserves" in Item 1 of this Form 10-K and incorporated by reference into this Item 2. Our proved reserves are based upon estimates prepared for each of our properties annually by the reservoir engineers assigned to the asset management team in the geographic locations in which the property is located. These estimates are reviewed by senior engineers who are not part of the asset management teams and by our Manager – Capital Budgeting & Reserves, who is the technical person primarily responsible for overseeing the preparation of our reserves estimates. Our Manager – Capital Budgeting & Reserves has 12 years of experience in petroleum engineering, including the estimation of oil and natural gas reserves, and holds a Bachelor of Science in Petroleum Engineering. Prior to joining us in 2009, our Manager – Capital Budgeting & Reserves served in various reservoir engineering roles for Kinder Morgan CO2 and Citation Oil & Gas and is a member of the Society of Petroleum Engineers. He reports to our Executive Vice President – Corporate Development who has more than 32 years of experience in reservoir engineering including the estimation of oil and natural gas reserves in multiple basins both in the United States and internationally. Prior to joining Southwestern in 2008, our Executive Vice President – Corporate Development served in various engineering and senior management roles for Tenneco Oil Company, Enron Oil & Gas Company, Enron Global Exploration & Production, El Paso Energy and The Houston Exploration Company, and is a member of the Society of Petroleum Engineers, IPAA, TIPRO and the Houston Producer's Forum. On our behalf, the Executive Vice President – Corporate Development engages NSAI, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies, to independently audit our proved reserves estimates. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-002699. Within NSAI, the two technical persons primarily responsible for auditing our proved reserves estimates (1) have over 32 years and over 12 years of practical experience in petroleum geosciences and petroleum engineering, respectively; (2) have over 22 years and over 12 years of experience in the estimation and evaluation of reserves, respectively; (3) each has a college degree; (4) each is a Licensed Professional Geoscientist in the State of Texas or a Licensed Professional Engineer in the State of Texas; (5) each meets or exceeds the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; and (6) each is proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines. The financial data included in the reserve estimates are also separately reviewed by our accounting staff. Our proved reserves estimates, as internally reviewed and audited by NSAI, are submitted for review and approval to our Chief Executive Officer. Finally, upon his approval, NSAI reports the results of its reserve audit to the Board of Directors with whom final authority over the estimates of our proved reserves rests. A copy of NSAI's report has been filed as Exhibit 99.1 to this Form 10-K.

The information regarding our proved undeveloped reserves required by Item 1203 of Regulation S-K is included under the heading "Proved Undeveloped Reserves" in "Business – Exploration and Production – Our Proved Reserves" in Item 1 of this Form 10-K.

The information regarding delivery commitments required by Item 1207 of Regulation S-K is included under the heading "Sales, Delivery Commitments and Customers" in the "Business – Exploration and Production – Our Operations" in Item 1 of this Form 10-K and incorporated by reference into this Item 2. For additional information about our natural gas and oil operations, we refer you to Note 4 to the consolidated financial statements. For information concerning capital investments, we refer you to "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Capital Investments." We also refer you to Item 6, "Selected Financial Data" in Part II of this Form 10-K for information concerning natural gas and oil produced.

The information regarding oil and gas properties, wells, operations and acreage required by Item 1208 of Regulation S-K is set forth below:

***Leasehold acreage as of December 31, 2013:***

| | Undeveloped | | Developed | |
|---|---|---|---|---|
| | Gross | Net | Gross | Net |
| Fayetteville Shale [1] | 495,510 | 291,360 | 816,840 | 490,104 |
| Marcellus Shale [2] | 307,330 | 246,838 | 45,871 | 45,608 |
| Ark-La-Tex: | | | | |
| Conventional Arkoma [3] | 67,084 | 60,375 | 184,812 | 166,331 |
| East Texas [4] | 411 | 172 | 71,310 | 50,279 |
| New Ventures: | | | | |
| USA New Ventures – LSBD [5] | 669,191 | 459,321 | 3,619 | 3,270 |
| USA New Ventures – Other [6] | 1,058,277 | 796,653 | – | – |
| Canada New Ventures [7] | 2,716,758 | 2,716,758 | – | – |
| | 5,314,561 | 4,571,477 | 1,122,452 | 755,592 |

(1) Assuming successful wells are not drilled to develop the acreage and leases are not extended, leasehold expiring over the next three years will be 22,092 net acres in 2014, 16,305 net acres in 2015, and 1,803 net acres in 2016 (excluding 155,852 net acres held on federal lands which are currently suspended by the Bureau of Land Management).

(2) Assuming successful wells are not drilled to develop the acreage and leases are not extended, leasehold expiring over the next three years will be 65,537 net acres in 2014, 32,637 net acres in 2015 and 19,233 net acres in 2016.

(3) Includes 123,442 net developed acres and 778 net undeveloped acres in the Arkoma Basin that are also within our Fayetteville Shale focus area but not included in the Fayetteville Shale acreage in the table above. Assuming successful wells are not drilled to develop the acreage and leases are not extended, leasehold expiring over the next three years will be 262 net acres in 2014, 7,437 net acres in 2015 and 574 net acres in 2016.

(4) Assuming successful wells are not drilled to develop the acreage and leases are not extended, leasehold expiring over the next three years will be 27 net acres in 2014, 64 net acres in 2015 and 0 net acres in 2016.

(5) Assuming successful wells are not drilled to develop the acreage and leases are not extended, leasehold expiring over the next three years will be 245,793 net acres in 2014, 151,667 net acres in 2015 and 25,891 net acres in 2016.

(6) Assuming successful wells are not drilled to develop the acreage and leases are not extended, leasehold expiring over the next three years will be 65,628 net acres in 2014, 143,708 net acres in 2015 and 224,346 net acres in 2016.

(7) Assuming successful wells are not drilled to develop the acreage and our exploration license agreements are not extended, leasehold expiring over the next three years will be 0 net acres in 2014, 2,518,518 net acres in 2015, and 48,960 net acres in 2016.

***Producing wells as of December 31, 2013:***

| | Natural Gas | | Oil | | Total | | Gross Wells |
|---|---|---|---|---|---|---|---|
| | Gross | Net | Gross | Net | Gross | Net | Operated |
| Fayetteville Shale [1] | 3,539 | 2,432 | – | – | 3,539 | 2,432 | 3,051 |
| Marcellus Shale [2] | 334 | 171 | – | – | 334 | 171 | 172 |
| Ark-La-Tex: | | | | | | | |
| Conventional Arkoma[3] | 1,164 | 566 | – | – | 1,164 | 566 | 550 |
| East Texas[4] | 166 | 105 | 7 | 4 | 173 | 109 | 134 |
| New Ventures | – | – | 3 | 3 | 3 | 3 | 3 |
| | 5,203 | 3,274 | 10 | 7 | 5,213 | 3,281 | 3,910 |

(1) As of December 31, 2013, this includes 1 gross natural gas well in which we own an overriding royalty interest.

(2) As of December 31, 2013, this includes 143 gross natural gas wells in which we own an overriding royalty interest.

(3) As of December 31, 2013, this includes 146 gross natural gas wells in which we own an overriding royalty interest.

(4) As of December 31, 2013, this includes 1 gross oil well and 12 gross natural gas wells in which we own an overriding royalty interest.

The information regarding drilling and other exploratory and development activities required by Item 1205 of Regulation S-K is set forth below:

Exploratory[1]

| | Productive Wells | | Dry Wells | | Total | |
|---|---|---|---|---|---|---|
| Year | Gross | Net | Gross | Net | Gross | Net |
| 2013 | 3.0 | 2.5 | 1.0 | 1.0 | 4.0 | 3.5 |
| 2012 | 7.0 | 7.0 | – | – | 7.0 | 7.0 |
| 2011 | 1.0 | 0.6 | – | – | 1.0 | 0.6 |

Development[1]

| | Productive Wells | | Dry Wells | | Total | |
|---|---|---|---|---|---|---|
| Year | Gross | Net | Gross | Net | Gross | Net |
| 2013[2] | 337.0 | 253.1 | 3.0 | 1.5 | 340.0 | 254.6 |
| 2012[3] | 376.0 | 257.0 | 9.0 | 6.7 | 385.0 | 263.7 |
| 2011 | 446.0 | 307.7 | – | – | 446.0 | 307.7 |

(1) We have not drilled any exploratory or development wells in Canada in the past three years.

(2) 2013 dry wells include 2 gross wells in the Fayetteville Shale that were plugged and abandoned after being spud due to changes in the development plans.

(3) 2012 dry wells include 5 gross wells that were use for science in the Ozark Highlands Unit that were not intended to produce.

The following table presents the information regarding our present activities required by Item 1206 of Regulation S-K:

***Wells in progress as of December 31, 2013:*** [1]

| | Gross | Net |
|---|---|---|
| Drilling: | | |
| Exploratory | 1.0 | 1.0 |
| Development | 150.0 | 113.2 |
| Total | 151.0 | 114.2 |
| Completing: | | |
| Exploratory | 2.0 | 2.0 |
| Development | 156.0 | 112.2 |
| Total | 158.0 | 114.2 |
| Drilling & Completing: | | |
| Exploratory | 3.0 | 3.0 |
| Development | 306.0 | 225.4 |
| Total | 309.0 | 228.4 |

(1) As of December 31, 2013, we did not have any drilling activities in Canada.

The information regarding oil and gas production, production prices and production costs required by Item 1204 of Regulation S-K is set forth below:

***Production, Average Sales Price and Average Production Cost:***

| | For the years ended December 31, | | |
|---|---|---|---|
| | **2013** | 2012 | 2011 |
| **Natural Gas** | | | |
| Production (Bcf): | | | |
| Fayetteville Shale | **486** | 486 | 437 |
| Marcellus Shale | **151** | 54 | 23 |
| Total | **656** | 565 | 499 |
| | | | |
| Average gas price per Mcf, excluding hedges: | | | |
| Fayetteville Shale | **$ 3.13** | $ 2.30 | $ 3.52 |
| Marcellus Shale | **3.25** | 2.55 | 3.80 |
| Total | **$ 3.17** | $ 2.34 | $ 3.56 |
| | | | |
| Average realized gas price per Mcf, including hedges | **$ 3.65** | $ 3.44 | $ 4.18 |
| | | | |
| **Oil** | | | |
| Oil production (MBbls)(1) | **138** | 83 | 97 |
| Average oil price per Bbl(1) | **$ 103.32** | $ 101.54 | $ 94.08 |
| | | | |
| **Average Production Cost** | | | |
| Cost per Mcfe, excluding ad valorem and severance taxes: | | | |
| Fayetteville Shale | **$ 0.86** | $ 0.83 | $ 0.88 |
| Marcellus Shale | **0.80** | 0.46 | 0.27 |
| Total | **$ 0.86** | $ 0.80 | $ 0.84 |

(1) Our Fayetteville Shale and Marcellus Shale operations did not produce any oil for the years ended December 31, 2013, 2012 and 2011.

During 2013, we were required to file Form 23, “Annual Survey of Domestic Oil and Gas Reserves,” with the U.S. Department of Energy. The basis for reporting reserves on Form 23 is not comparable to the reserve data included in Note 4 to the consolidated financial statements in Item 8 to this Form 10-K. The primary differences are that Form 23 reports gross reserves, including the royalty owners’ share, and includes reserves for only those properties of which we are the operator.

## Miles of Pipe

As of December 31, 2013, our Midstream Services segment had 1,947 miles, 90 miles, 25 miles and 9 miles of pipe in its gathering systems located in Arkansas, Pennsylvania, Texas and Louisiana, respectively.

## Title to Properties

We believe that we have satisfactory title to substantially all of our active properties in accordance with standards generally accepted in the oil and gas industry. Our properties are subject to customary royalty and overriding royalty interests, certain contracts relating to the exploration, development, operation and marketing of production from such properties, consents to assignment and preferential purchase rights, liens for current taxes, applicable laws and other burdens, encumbrances and irregularities in title, which we believe do not materially interfere with the use of or affect the value of such properties. Prior to acquiring undeveloped properties, we endeavor to perform a title investigation that is thorough but less vigorous than that we endeavor to conduct prior to drilling, which is consistent with standard practice in the oil and natural gas industry. Generally, before we commence drilling operations on properties that we operate, we conduct a title examination and perform curative work with respect to significant defects that we identify. We believe that we have performed title examination with respect to substantially all of our active properties that we operate.

## ITEM 3. LEGAL PROCEEDINGS

We are subject to laws and regulations relating to the protection of the environment. Our policy is to accrue environmental and cleanup related costs of a non-capital nature when it is both probable that a liability has been incurred and when the amount can be reasonably estimated. Management believes any future remediation or other compliance related costs will not have a material effect on our financial position, results of operations, and cash flows.

Tovah Energy

In February 2009, SEPCO was added as a defendant in a case then styled Tovah Energy, LLC and Toby Berry-Helfand v. David Michael Grimes, et, al., pending in the 273rd District Court in Shelby County, Texas. By the time of trial in December 2010, Ms. Berry-Helfand (the only remaining plaintiff) alleged that, in 2005, she provided SEPCO with proprietary data regarding two prospects in the James Lime formation pursuant to a confidentiality agreement and that SEPCO refused to return the proprietary data to the plaintiff, subsequently acquired leases based upon such proprietary data and profited therefrom. Among other things, she alleged various statutory and common law claims, including, but not limited to, claims of misappropriation of trade secrets, violation of the Texas Theft Liability Act, breach of fiduciary duty and confidential relationships, various fraud based claims and breach of contract, including a claim of breach of a purported right of first refusal on all interests acquired by SEPCO between February 2005 and February 2006. She also sought disgorgement of SEPCO's profits. A former associate of the plaintiff intervened in the matter claiming to have helped develop the prospect years earlier.

The jury found in favor of the plaintiff and the intervenor with respect to all of the statutory and common law claims and awarded $11.4 million in compensatory damages but no special, punitive or other damages. Separately, the jury determined that SEPCO's profits for purposes of disgorgement, if ordered as a remedy, were $381.5 million. (Disgorgement of profits is an equitable remedy determined by the judge, and it is within the judge's discretion to award none, some or all of unlawfully obtained profits.) In August 2011, a judgment was entered pursuant to which the plaintiff and the intervenor were entitled to recover approximately $11.4 million in actual damages and approximately $23.9 million in disgorgement as well as prejudgment interest and attorneys' fees, which currently are estimated to be up to $8.9 million, and all costs of court of the plaintiff and intervenor.

Both sides appealed and in July 2013, the Tyler Court of Appeals ordered that (1) the judgment awarding the plaintiff and the intervenor $23.9 million as disgorgement of illicit gains be reversed and judgment rendered that they take nothing, (2) the award of $11.4 million for actual damages, insofar as it is based on the jury's findings of breach of fiduciary duty, fraud, breach of contract, and theft of trade secret is reversed and judgment rendered that the plaintiff and the intervenor take nothing under those theories of recovery, (3) the award of $11.4 million to the plaintiff and the intervenor as damages for misappropriation of trade secret is affirmed, (4) the case be remanded to the trial court for a determination and award of attorney's fees for SEPCO as the prevailing party under the Texas Theft Liability Act, and (5) in all other respects, the judgment is affirmed. All parties petitioned for rehearing. The Tyler Court of Appeals denied rehearing in November 2013.

SEPCO filed a petition for review in the Supreme Court of Texas in February 2014. The plaintiff and the intervenor have until March 2014 to file petitions for review. Based on the Company's understanding and judgment of the facts and merits of this case, including appellate matters, and after considering the advice of counsel, the Company has determined that, although reasonably possible, a materially adverse final outcome to this action is not probable. As such, the Company has not accrued any amounts with respect to this action. If the plaintiff and the intervenor were to prevail ultimately in the appellate process, the Company currently estimates, based on the judgments to date, that SEPCO's potential liability would be up to $45.5 million, including interest and attorney's fees. If the Supreme Court declines to hear the case or affirms all aspects of the court of appeals' judgment, then SEPCO would owe the $11.4 million in damages, plus interest and attorneys fees, offset by any award of attorneys' fees for its prevailing on the theft count. The Company's assessment may change in the future due to occurrence of certain events, such as the result of the petition or petitions for review at the Supreme Court of Texas, and such a re-assessment could lead to the determination that the potential liability is probable and could be material to the Company's results of operations, financial position or cash flows.

Bureau of Land Management

In March 2010, the Company's subsidiary SEECO was served with a subpoena from a federal grand jury in Little Rock, Arkansas. Based on the documents requested under the subpoena and subsequent discussions with representatives of the Bureau of Land Management and the U.S. Attorney, the Company believed the grand jury was investigating matters involving approximately 27 horizontal wells operated by SEECO in Arkansas, including whether appropriate leases or permits were obtained therefrom and whether royalties and other production attributable to federal lands were properly accounted for and paid. In January 2014, the U.S. Attorney's office informed SEECO's outside counsel that no criminal charges will be brought. Two wells were drilled, in part, through federal lands without having obtained leases at the time of drilling, and SEECO has paid full royalties as if those leases were in place from first production of the wells. The Government has made a formal demand for additional damages for trespass; however, because these actions were not deliberate and SEECO voluntarily reported this to the Bureau of Land Management at the time the error was discovered, the Company does not believe additional damages should be assessable or that such additional damages, if any, would be material.

Other

The Company is subject to various litigation, claims and proceedings that have arisen in the ordinary course of business, such as for alleged breaches of contract, miscalculation of royalties and pollution, contamination or nuisance. Management believes that such litigation, claims and proceedings, individually or in aggregate and after taking into account insurance, are not likely to have a material adverse impact on our financial position, results of operations or cash flows. Many of these matters are in early stages, so the allegations and the damage theories have not been fully developed, and all subject to inherent uncertainties; therefore, management's view may change in the future. If an unfavorable final outcome were to occur, there exists the possibility of a material impact on the Company's financial position, results of operations or cash flows for the period in which the effect becomes reasonably estimable. The Company accrues for such items when a liability is both probable and the amount can be reasonably estimated.

## ITEM 4. MINE SAFETY DISCLOSURES

Our sand mining operations in support of our E&P business are subject to regulation by the Federal Mine Safety and Health Administration under the Federal Mine Safety and Health Act of 1977. Information concerning mine safety violations or other regulatory matters required by section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K (17 CFR 229.106) is included in Exhibit 95.1 to this Form 10-K.

## PART II

### ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common stock is traded on the New York Stock Exchange (the "NYSE") under the symbol "SWN." On February 24, 2014, the closing price of our stock was $43.29 and we had 3,207 stockholders of record. The following table presents the high and low sales prices for closing market transactions as reported on the NYSE.

| | Range of Market Prices | | | | | |
|---|---|---|---|---|---|---|
| Quarter Ended | **2013** | | 2012 | | 2011 | |
| March 31 | **$ 38.86** | **$ 32.09** | $ 35.60 | $ 29.06 | $ 43.49 | $ 36.12 |
| June 30 | **$ 39.58** | **$ 34.97** | $ 32.46 | $ 25.82 | $ 43.86 | $ 38.02 |
| September 30 | **$ 39.91** | **$ 36.38** | $ 35.76 | $ 30.55 | $ 49.00 | $ 33.33 |
| December 31 | **$ 40.18** | **$ 35.16** | $ 36.60 | $ 32.78 | $ 44.21 | $ 31.94 |

We do not currently pay quarterly cash dividends on our common stock.

***Issuer Purchases of Equity Securities***

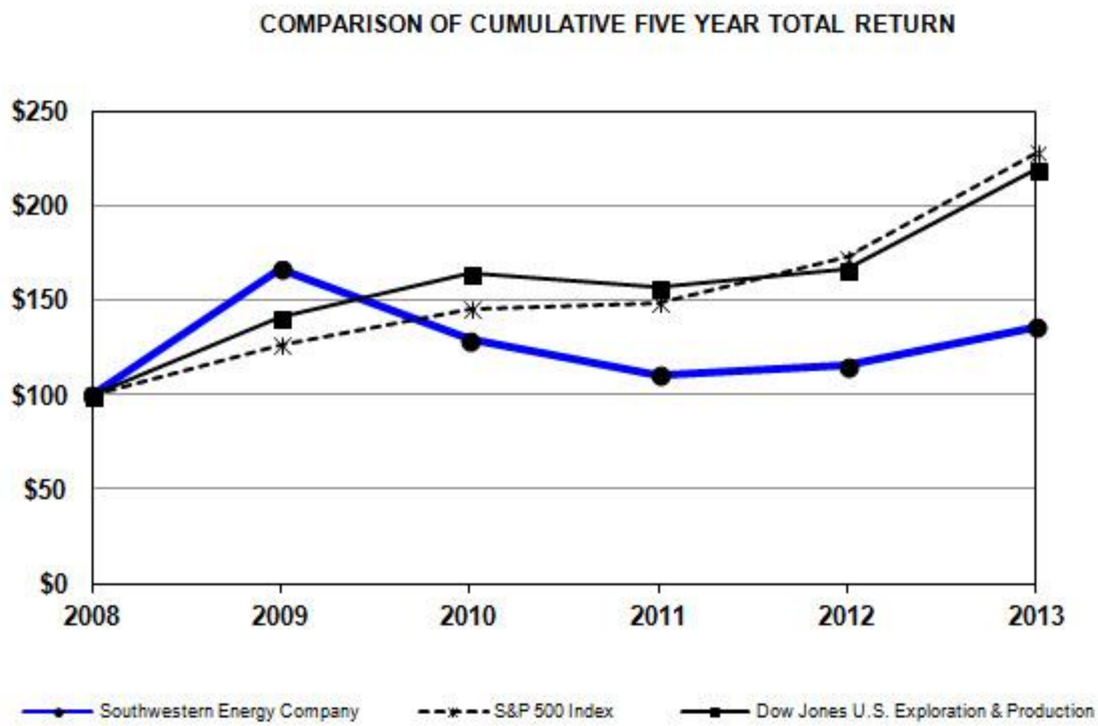
During 2013, we retired 25,131 shares for the payment of withholding taxes due on employee stock plan share issuances. All changes in common stock in treasury in 2013 were due to purchases and sales of shares held on behalf of participants in a non-qualified deferred compensation supplemental retirement savings plan. We refer you to Note 1 to our consolidated financial statements in Item 8 of Part II.

***Recent Sales of Unregistered Equity Securities***

We did not sell any unregistered equity securities during 2013, 2012 or 2011.

## STOCK PERFORMANCE GRAPH

The following graph compares, for the last five years, the performance of our common stock to the S&P 500 Index and the Dow Jones U.S. Exploration & Production Index. The chart assumes that the value of the investment in our common stock and each index was $100 at December 31, 2008, and that all dividends were reinvested. The stock performance shown on the graph below is not indicative of future price performance.




| | 12/31/08 | 12/31/09 | 12/31/10 | 12/31/11 | 12/31/12 | 12/31/13 |
|---|---|---|---|---|---|---|
| Southwestern Energy Company | 100 | 166 | 129 | 110 | 115 | 136 |
| Dow Jones U.S. Exploration & Production | 100 | 126 | 146 | 149 | 172 | 228 |
| S&P 500 Index | 100 | 141 | 164 | 157 | 166 | 219 |

## ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth a summary of selected historical financial information for each of the years in the five-year period ended December 31, 2013. This information and the notes thereto are derived from our consolidated financial statements. We refer you to "Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Financial Statements and Supplementary Data."

| | **2013** | 2012 | 2011 | 2010 | 2009 |
|---|---|---|---|---|---|
| | (in thousands except shares, per share, stockholder data and percentages) | | | | |
| **Financial Review** | | | | | |
| Operating revenues: | | | | | |
| Exploration and production | **$ 2,404,165** | $ 1,963,172 | $ 2,098,914 | $ 1,894,972 | $ 1,616,461 |
| Midstream services | **3,346,683** | 2,363,480 | 2,859,519 | 2,453,840 | 1,603,332 |
| Other | **340** | 2,865 | 3,268 | 984 | 687 |
| Intersegment revenues | **(2,380,043)** | (1,599,524) | (2,010,369) | (1,734,605) | (1,051,471) |
| | **3,371,145** | 2,729,993 | 2,951,332 | 2,615,191 | 2,169,009 |
| Operating costs and expenses: | | | | | |
| Gas purchases – midstream services | **781,626** | 592,466 | 709,091 | 611,161 | 482,836 |
| Operating and general and administrative expenses | **519,813** | 419,882 | 398,985 | 337,334 | 259,159 |
| Depreciation, depletion and amortization | **786,612** | 810,953 | 704,511 | 590,332 | 493,658 |
| Impairment of natural gas and oil properties | **–** | 1,939,734 | – | – | 907,812 |
| Taxes, other than income taxes | **79,471** | 67,584 | 65,518 | 50,608 | 37,280 |
| | **2,167,522** | 3,830,619 | 1,878,105 | 1,589,435 | 2,180,745 |
| Operating income (loss) | **1,203,623** | (1,100,626) | 1,073,227 | 1,025,756 | (11,736) |
| | | | | | |
| Interest expense, net | **41,594** | 35,657 | 24,075 | 26,163 | 18,638 |
| Other income, net | **2,207** | 1,030 | 264 | 427 | 1,449 |
| Gain (loss) on derivatives | **26,141** | (14,950) | 1,574 | (4,528) | (23,230) |
| Income (loss) before income taxes | **1,190,377** | (1,150,203) | 1,050,990 | 995,492 | (52,155) |
| Provision (benefit) for income taxes: | | | | | |
| Current | **(11,071)** | 18,689 | 4,198 | 11,939 | (64,969) |
| Deferred | **497,945** | (461,828) | 409,023 | 379,720 | 48,606 |
| | **486,874** | (443,139) | 413,221 | 391,659 | (16,363) |
| Net income (loss) | **703,503** | (707,064) | 637,769 | 603,833 | (35,792) |
| Less: net loss attributable to noncontrolling interest | **–** | – | – | (285) | (142) |
| Net income (loss) attributable to Southwestern Energy | **$ 703,503** | $ (707,064) | $ 637,769 | $ 604,118 | $ (35,650) |
| Return on equity | **19.4%** | (23.3%) | 16.1% | 20.4% | (1.5%) |
| Net cash provided by operating activities | **$ 1,908,528** | $ 1,653,942 | $ 1,739,817 | $ 1,642,585 | $ 1,359,376 |
| Net cash used in investing activities | **$ (2,215,776)** | $ (1,906,677) | $ (2,024,790) | $ (1,725,631) | $ (1,780,604) |
| Net cash provided by financing activities | **$ 277,199** | $ 290,889 | $ 284,303 | $ 86,240 | $ 238,135 |
| | | | | | |
| **Common Stock Statistics** | | | | | |
| Earnings per share: | | | | | |
| Net income (loss) attributable to Southwestern stockholders – Basic | **$ 2.01** | $ (2.03) | $ 1.84 | $ 1.75 | $ (0.10) |
| Net income (loss) attributable to Southwestern stockholders – Diluted | **$ 2.00** | $ (2.03) | $ 1.82 | $ 1.73 | $ (0.10) |
| Book value per average diluted share | **$ 10.32** | $ 8.71 | $ 11.34 | $ 8.49 | $ 6.82 |
| Market price at year-end | **$ 39.33** | $ 33.41 | $ 31.94 | $ 37.43 | $ 48.20 |
| Number of stockholders of record at year-end | **3,259** | 3,122 | 3,083 | 3,043 | 2,639 |
| Average diluted shares outstanding | **351,101,452** | 348,610,503 | 349,921,413 | 349,310,666 | 343,420,568 |

| | 2013 | 2012 | 2011 | 2010 | 2009 |
|---|---|---|---|---|---|
| **Capitalization** (in thousands) | | | | | |
| Total debt | **$ 1,951,296** | $ 1,669,473 | $ 1,343,300 | $ 1,094,200 | $ 998,700 |
| Total equity | **3,622,030** | 3,035,872 | 3,969,304 | 2,964,876 | 2,340,981 |
| Total capitalization | **$ 5,573,326** | $ 4,705,345 | $ 5,312,604 | $ 4,059,076 | $ 3,339,681 |
| Total assets | **$ 8,047,726** | $ 6,737,527 | $ 7,902,897 | $ 6,017,463 | $ 4,770,250 |
| Capitalization ratios: | | | | | |
| Debt | **35%** | 35% | 25% | 27% | 30% |
| Equity | **65%** | 65% | 75% | 73% | 70% |
| **Capital Investments** (in millions) (1) | | | | | |
| Exploration and production | **2,052** | 1,861 | 1,978 | 1,776 | 1,566 |
| Midstream services | **158** | 165 | 161 | 271 | 214 |
| Other | **25** | 55 | 68 | 73 | 29 |
| | **$ 2,235** | $ 2,081 | $ 2,207 | $ 2,120 | $ 1,809 |
| **Exploration and Production** | | | | | |
| Natural gas: | | | | | |
| Production, Bcf | **656** | 565 | 499 | 404 | 300 |
| Average realized price per Mcf, including hedges | **$ 3.65** | $ 3.44 | $ 4.18 | $ 4.62 | $ 5.35 |
| Average price per Mcf, excluding hedges | **$ 3.17** | $ 2.34 | $ 3.56 | $ 3.93 | $ 3.34 |
| Oil: | | | | | |
| Production, MBbls | **138** | 83 | 97 | 171 | 124 |
| Average price per barrel, including hedges | **$ 103.32** | $ 101.54 | $ 94.08 | $ 76.84 | $ 54.99 |
| Average price per barrel, excluding hedges | **$ 103.32** | $ 101.54 | $ 94.08 | $ 76.84 | $ 54.99 |
| NGL: | | | | | |
| Production, MBbls | **50** | – | – | – | – |
| Average price per barrel, including hedges | **$ 43.63** | $ – | $ – | $ – | $ – |
| Average price per barrel, excluding hedges | **$ 43.63** | $ – | $ – | $ – | $ – |
| Total natural gas and oil production, Bcfe | **657** | 565 | 500 | 405 | 300 |
| Lease operating expenses per Mcfe | **$ 0.86** | $ 0.80 | $ 0.84 | $ 0.83 | $ 0.77 |
| General and administrative expenses per Mcfe | **$ 0.24** | $ 0.26 | $ 0.27 | $ 0.30 | $ 0.35 |
| Taxes, other than income taxes per Mcfe | **$ 0.10** | $ 0.10 | $ 0.11 | $ 0.11 | $ 0.11 |
| Proved reserves at year-end: | | | | | |
| Natural gas, Bcf | **6,974** | 4,017 | 5,887 | 4,930 | 3,650 |
| Oil, MMBbls | – | – | 1 | 1 | 1 |
| Total reserves, Bcfe | **6,976** | 4,018 | 5,893 | 4,937 | 3,657 |
| **Midstream Services** | | | | | |
| Gas volumes marketed, Bcf | **786** | 676 | 611 | 496 | 382 |
| Gas volumes gathered, Bcf | **900** | 846 | 746 | 588 | 387 |

(1) Capital investments include decreases of $25 million for 2013, $37 million for 2012, and increases of $4 million for 2011, $14 million for 2010, and $12 million for 2009 related to the change in accrued expenditures between years.

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

This Form 10-K contains forward-looking statements that involve risks and uncertainties. Our actual results could differ materially from those anticipated in forward-looking statements for many reasons, including the risks described in the "Cautionary Statement About Forward-Looking Statements" below, in Item 1A, "Risk Factors" in Part I and elsewhere in this annual report. You should read the following discussion with the "Item 6. Selected Financial Data" and our consolidated financial statements and the related notes included in this Form 10-K.

### OVERVIEW

**Background**

Southwestern Energy Company is an independent energy company engaged in natural gas and oil exploration, development and production, or E&P. We are also focused on creating and capturing additional value through our natural gas gathering and marketing businesses, which we refer to as Midstream Services. We operate principally in two segments: E&P and Midstream Services.

Our primary business is the exploration for and production of natural gas and oil, with our current operations being almost entirely within the United States. We are actively engaged in exploration and production activities in Arkansas, where we are targeting the unconventional gas reservoir known as the Fayetteville Shale, in Pennsylvania, where we are targeting the unconventional gas reservoir known as the Marcellus Shale, and to a lesser extent in Texas and in Arkansas and Oklahoma in the Arkoma Basin. We have commenced exploration operations in Arkansas and Louisiana testing an unconventional oil play targeting the Lower Smackover Brown Dense. In 2010, we commenced an exploration program in New Brunswick, Canada, which represents our first operations outside of the United States.

We are focused on providing long-term growth in the net asset value of our business. We derive the vast majority of our operating income and cash flow from the natural gas production of our E&P business and expect this to continue in the future. We expect that growth in our operating income and revenues will depend primarily on natural gas prices and our ability to increase our natural gas production. We expect our natural gas production volumes will continue to increase due to our ongoing development of the Fayetteville Shale in Arkansas and the Marcellus Shale in Pennsylvania. The price we expect to receive for our natural gas is a critical factor in the capital investments we make in order to develop our properties and increase our production. In recent years, there has been significant volatility in natural gas prices as evidenced by New York Mercantile Exchange, or NYMEX, natural gas prices ranging from a high of $13.58 per MMBtu in 2008 to a recent low of $1.91 per MMBtu in 2012. Natural gas prices fluctuate due to a variety of factors we cannot control or predict. These factors, which include increased supplies of natural gas due to greater exploration and development activities, weather conditions, political and economic events, and competition from other energy sources, impact supply and demand for natural gas, which in turn determines the sale prices for our production. In addition to the factors identified above, the prices we realize for our production are affected by our hedging activities as well as locational differences in market prices.

**Recent Financial and Operating Results**

In 2013, our net income was $703.5 million, or $2.00 per diluted share, up from a net loss of $707.1 million, or $2.03 per diluted share in 2012. Our net income was $637.8 million, or $1.82 per diluted share in 2011. In 2012, we incurred a $1,939.7 million, or $1,192.4 million net of taxes, non-cash ceiling test impairment of our United States natural gas and oil properties that resulted from a significant decline in natural gas prices during 2012. Our cash flow from operating activities increased 15% to $1,908.5 million in 2013 due to an increase in net income adjusted for non-cash expenses which was partially offset by changes in working capital accounts, and decreased 5% to $1,653.9 million in 2012 due to a decrease in net income adjusted for non-cash expenses which was partially offset by changes in working capital.

In 2013, our natural gas and oil production increased 16% to 656.8 Bcfe, up from 565.0 Bcfe in 2012. The 91.8 Bcfe increase in our 2013 production resulted from a 97.0 Bcf increase in net production from our Marcellus Shale properties, a 1.4 Bcfe increase in net production in our New Ventures properties, and a 0.5 Bcf increase in net production from our Fayetteville Shale properties, which more than offset a combined 7.1 Bcfe decrease in net production from our East Texas and Arkoma Basin properties. In 2012, our natural gas and oil production increased to 565.0 Bcfe, up from 500.0 Bcfe in 2011. We are targeting 2014 natural gas and oil production of 740.0 to 752.0 Bcfe, an increase of approximately 14% over our 2013 production, using midpoints. Our year-end reserves increased 74% in 2013 to 6,976.3 Bcfe, up from 4,018.3 Bcfe at the end of 2012 and 5,893.2 Bcfe at the end of 2011. The overall increase in total estimated proved reserves in 2013 was primarily due to the higher average natural gas prices in 2013 compared to 2012, leading to a significant increase in our Fayetteville Shale reserves and a 141% growth rate in our reserves in the Marcellus Shale. The decrease in total estimated proved reserves in 2012 was primarily due to the low natural gas price environment in 2012.

Our E&P segment operating income was $878.7 million in 2013, up from an operating loss of $1,396.3 million in 2012. The operating loss in 2012 included a $1,939.7 million non-cash ceiling test impairment of our United States natural gas and oil properties. Excluding the non-cash ceiling test impairment, operating income in 2013 increased $335.2 million over 2012 as the revenue impact of our 16%, or 91.8 Bcfe, increase in production and 6%, or $0.21, increase in our average realized natural gas prices more than offset the $105.8 million increase in operating costs and expenses that resulted from increased activity levels. Excluding the non-cash ceiling test impairment, operating income of $543.5 million in 2012 decreased $280.1 million over 2011 as the revenue impact of our 13%, or 65.0 Bcfe, increase in production was more than offset by the 18%, or $0.74, decline in our average realized natural gas prices and a $144.3 million increase in operating costs that resulted from increased activity levels.

Operating income for our Midstream Services segment was $325.4 million in 2013, up from $294.3 million in 2012 and $248.0 million in 2011. Operating income for our Midstream Services segment increased in 2013 due to an increase of $42.3 million in gathering revenues and a $16.8 million increase in the margin generated from our natural gas marketing activities, which was partially offset by a $28.0 million increase in operating costs and expenses, exclusive of natural gas purchase costs, that resulted from our continued growth in volumes gathered. Volumes gathered grew to 900.1 Bcf in 2013 compared to 845.5 Bcf in 2012. Operating income for our Midstream Services segment increased in 2012 due to an increase of $65.8 million in gathering revenues, which was partially offset by a decrease of $2.5 million in the margin generated from our natural gas marketing activities and $17.0 million increase in operating costs and expenses, exclusive of natural gas purchase costs, that resulted from our growth in volumes gathered. Volumes gathered grew to 845.5 Bcf in 2012 compared to 745.7 Bcf in 2011.

We had total capital investments of $2,234.8 million in 2013, compared to $2,080.5 million in 2012 and $2,207.2 million in 2011. Of our total capital investments, $2,052.1 million was invested in our E&P segment in 2013 compared to $1,860.7 million and $1,977.5 million invested in our E&P segment in 2012 and 2011, respectively.

**Outlook**

We believe the outlook for our business is favorable despite the continued uncertainty of natural gas prices in the United States and the legislative and regulatory challenges facing our industry. Our resource base, financial strength and disciplined investment of capital provide us with an opportunity to exploit and develop our position in the Fayetteville Shale and the Marcellus Shale, maximize efficiency through economies of scale in our key operating areas, enhance our overall returns through expansion of our Midstream Services operations and grow through new exploration and development activities. Our capital investment plan for 2014 is flexible and is based on our expectation that natural gas prices will remain at current price levels. Should prices fluctuate materially from their current levels we will adjust our capital investment plans accordingly.

## RESULTS OF OPERATIONS

The following discussion of our results of operations for our segments is presented before intersegment eliminations. We evaluate our segments as if they were stand-alone operations and accordingly discuss their results prior to any intersegment eliminations. Interest expense, interest income, income tax expense and stock-based compensation are discussed on a consolidated basis.

### Exploration and Production

| | For the year ended December 31, 2013 | 2012 | 2011 |
|---|---|---|---|
| Revenues (in thousands) | $ 2,404,165 | $ 1,963,172 | $ 2,098,914 |
| Impairment of natural gas and oil properties (in thousands) | $ – | $ 1,939,734 | $ – |
| Operating costs and expenses (in thousands) | $ 1,525,464 | $ 1,419,699 | $ 1,275,350 |
| Operating income (loss) (in thousands) | $ 878,701 | $ (1,396,261) | $ 823,564 |
| Gain (loss) on derivatives[1] | $ 4,772 | $ (12,796) | $ (4,026) |
| | | | |
| Gas production (Bcf) | 655.7 | 564.5 | 499.4 |
| Oil production (MBbls) | 137.7 | 83.0 | 97.0 |
| NGL production (MBbls) | 50.2 | – | – |
| Total production (Bcfe) | 656.8 | 565.0 | 500.0 |
| | | | |
| Average realized gas price per Mcf, including hedges [2] | $ 3.65 | $ 3.44 | $ 4.18 |
| Average realized gas price per Mcf, excluding hedges | $ 3.17 | $ 2.34 | $ 3.56 |
| Average oil price per Bbl | $ 103.32 | $ 101.54 | $ 94.08 |
| Average NGL price per Bbl | $ 43.63 | $ – | $ – |
| | | | |
| Average unit costs per Mcfe: | | | |
| Lease operating expenses | $ 0.86 | $ 0.80 | $ 0.84 |
| General & administrative expenses | $ 0.24 | $ 0.26 | $ 0.27 |
| Taxes, other than income taxes | $ 0.10 | $ 0.10 | $ 0.11 |
| Full cost pool amortization | $ 1.08 | $ 1.31 | $ 1.30 |

(1) Represents the commodity gain (loss) on derivatives, settled, associated with derivatives not designated for hedge accounting. Includes basis and fair value hedge positions.
(2) Had we included the commodity gain (loss) on derivatives, net of settlement effects of commodity hedging contracts not designated for hedge accounting, our average price for total natural gas would have been $3.67, $3.44 and $4.19 for the year ended December 31, 2013, 2012 and 2011, respectively.

*Revenues*

Revenues for our E&P segment were up $441.0 million, or 22%, in 2013 compared to 2012. Higher natural gas production volumes in 2013 increased revenues by $315.6 million, higher realized prices for our natural gas production increased revenue by $118.0 million, and higher oil production volumes in 2013 increased revenues by $5.6 million compared to 2012. E&P revenues were down $135.7 million, or 6%, in 2012 compared to 2011. Higher natural gas production volumes in 2012 increased revenues by $272.4 million while lower realized prices for our natural gas production decreased revenue by $410.4 million. We expect our natural gas production volumes to continue to increase due to our development of the Marcellus Shale properties in Pennsylvania. Natural gas and oil prices are difficult to predict and subject to wide price fluctuations. As of February 24, 2014, we had hedged 455.8 Bcf and 119.5 Bcf of our remaining 2014 and 2015 natural gas production, respectively, to help limit our exposure to price fluctuations. For more information about our derivatives and risk management activities, we refer you to Note 5 to the consolidated financial statements included in this Form 10-K and to "Commodity Prices" below for additional information.

*Production*

In 2013, our natural gas and oil production increased 16% to 656.8 Bcfe, up from 565.0 Bcfe in 2012. The 91.8 Bcfe increase in our 2013 production resulted from a 97.0 Bcf increase in net production from our Marcellus Shale properties, a 1.4 Bcfe increase in net production in our New Ventures properties, and a 0.5 Bcf increase in net production from our Fayetteville Shale properties, which more than offset a combined 7.1 Bcfe decrease in net production from our East Texas and Arkoma Basin properties. In 2012, our natural gas and oil production increased to 565.0 Bcfe, up from 500.0 Bcfe in 2011. The 65.0 Bcfe increase in our 2012 production resulted from a 48.7 Bcf increase in net production from our Fayetteville Shale properties, a 30.3 Bcf increase in net production from our Marcellus Shale properties and a 0.3 Bcfe increase in net production in our New Ventures properties, which more than offset a combined 14.3 Bcfe decrease in net production from our East Texas and Arkoma Basin properties. Our net production from the Fayetteville Shale was 486.0 Bcf in 2013, up from 485.5 Bcf in 2012 and 436.8 Bcf in 2011. Our net production from the Marcellus Shale was 150.6 Bcf in 2013, up from 53.6 Bcf in 2012 and 23.4 Bcf in 2011.

We are targeting 2014 natural gas and oil production of 740.0 to 752.0 Bcfe, an increase of approximately 14% over our 2013 production, using midpoints. Approximately 479.0 to 484.0 Bcf of our 2014 targeted natural gas production is projected to come from our activities in the Fayetteville Shale and 244.0 to 249.0 Bcf is projected to come from our activities in the Marcellus Shale. Although we expect production volumes in 2014 to increase, we cannot guarantee our success in discovering, developing and producing total Company reserves. Our ability to discover, develop and produce reserves is dependent upon a number of factors, many of which are beyond our control, including the availability of capital, availability of transportation, weather, the timing and extent of changes in natural gas and oil prices and competition. There are also many risks inherent in the discovery, development and production of natural gas and oil. We refer you to "Risk Factors" in Item 1A of Part I of this Form 10-K for a discussion of these risks and the impact they could have on our financial condition and results of operations.

*Commodity Prices*

The average price realized for our natural gas production, including the effects of hedges, increased 6% to $3.65 per Mcf in 2013 and decreased 18% to $3.44 per Mcf in 2012. The increase in the average price realized in 2013 compared to 2012 primarily reflects the increase in average market prices and to a lesser extent the decreased effect of our natural gas price hedging activities, which had a greater positive impact on our average realized natural gas price in 2012 (see additional discussion below). The decrease in the average price realized in 2012 compared to 2011 primarily reflects the decrease in average market prices, which was partially offset by the positive effect of our price hedging activities in 2012. We periodically enter into various hedging and other financial arrangements with respect to a portion of our projected natural gas and oil production in order to ensure certain desired levels of cash flow and to minimize the impact of price fluctuations, including fluctuations in locational market differentials. We refer you to Item 7A of this Form 10-K, Note 5 to the consolidated financial statements, and our hedge risk factor for additional discussion about our derivatives and risk management activities.

Our hedging activities increased the average natural gas sales price we realized by $0.48 per Mcf in 2013, compared to an increase of $1.10 per Mcf in 2012 and an increase of $0.62 per Mcf in 2011. Disregarding the impact of hedges, the average realized sales price we received for our natural gas production in 2013 was $0.83 per Mcf higher than 2012 and $0.48 lower than the average monthly NYMEX settlement price for 2013.

As of December 31, 2013, we have attempted to mitigate the volatility of basis differentials by protecting basis on approximately 242.0 Bcf of our 2014 expected natural gas production through financial hedging activities and physical sales arrangements at a basis differential to NYMEX natural gas prices of approximately ($0.09) per Mcf.

In addition to the basis protection discussed above, as of December 31, 2013, we had NYMEX fixed price hedges in place on notional volumes of 382.3 Bcf of our 2014 natural gas production at an average price of $4.33 per MMBtu.

Our E&P segment receives a sales price for our natural gas at a discount to average monthly NYMEX settlement prices due to locational basis differentials, transportation charges and fuel charges. Assuming a NYMEX commodity price of $3.75 per Mcf for 2014, and disregarding the impact of hedges, we expect our total natural gas sales discount to NYMEX to be $0.55 to $0.60 per Mcf for 2014.

We realized an average sales price of $103.32 per barrel for our oil production for the year ended December 31, 2013, up approximately 2% from the prior year. The 2012 average realized price of $101.54 per barrel was up 8% from 2011. We did not hedge any of our 2013, 2012 or 2011 oil production.

*Operating Income*

Our E&P segment operating income was $878.7 million in 2013, up from an operating loss of $1,396.3 million in 2012. The operating loss in 2012 included a $1,939.7 million non-cash ceiling test impairment of our United States natural gas and oil properties. Excluding the $1,939.7 million non-cash ceiling test impairment, operating income in 2013 increased $335.2 million over 2012 as the revenue impact of our 16%, or 91.8 Bcfe, increase in production and 6%, or $0.21, increase in our average realized natural gas prices which more than offset the $105.8 million increase in operating costs and expenses that resulted from our significant production growth. Excluding the $1,939.7 million non-cash ceiling test impairment, operating income of $543.5 million in 2012 decreased $280.1 million as compared to 2011 as the revenue impact of our 13%, or 65.0 Bcfe, increase in production was more than offset by the 18%, or $0.74, decline in our average realized natural gas prices and a $144.3 million increase in operating costs that resulted from our significant production growth.

*Operating Costs and Expenses*

Lease operating expenses per Mcfe for the E&P segment were $0.86 in 2013, compared to $0.80 in 2012 and $0.84 in 2011. Lease operating expenses per unit of production increased in 2013 primarily due to increased gathering and compression costs associated with our Marcellus Shale operations, offset slightly by decreased salt water disposal costs associated with our Fayetteville Shale operations. Lease operating expenses per unit of production decreased in 2012 compared to 2011 primarily due to lower compression and salt water disposal costs associated with our Fayetteville Shale operations. We expect our per unit lease operating cost to range between $0.88 and $0.93 per Mcfe in 2014.

General and administrative expenses for the E&P segment were $0.24 per Mcfe in 2013, down from $0.26 per Mcfe in 2012 and $0.27 per Mcfe in 2011. The decreases in general and administrative costs per Mcfe in 2013 and 2012 were primarily due to a decrease in personnel costs per unit of production, due to our significant increase in production in 2013. In total, general and administrative expenses for the E&P segment were $157.3 million in 2013, $145.1 million in 2012 and $134.8 million in 2011. The increase in general and administrative expenses in 2013 was primarily a result of increased personnel costs and professional fees associated with the expansion of our E&P operations, offset slightly by decreased information system costs and bad debt expense. This net increase accounted for $11.0 million, or 89%, of the 2013 increase. The increase in general and administrative expenses in 2012 was primarily a result of increased personnel and information system costs associated with the expansion of our E&P operations. These increases accounted for $8.9 million, or 86%, of the 2012 increase. We added 159 new E&P employees during 2013 compared to 131 employees added in 2012.

We expect our per unit cost for general and administrative expenses in 2014 to range between $0.24 and $0.28 per Mcfe. The expected increase in our per unit general and administrative costs in 2014 is due to general increases in personnel costs. Future changes in our general and administrative expenses for this segment are primarily dependent upon personnel costs and the level of our operating activities. For eligible employees, a portion of incentive compensation is based on the achievement of certain operating and performance results, including production, proved reserve additions, present value added for each dollar of capital invested, lease operating expenses and general and administrative expenses per unit of production, while another portion is discretionary based upon an employee’s performance.

Taxes other than income taxes per Mcfe were $0.10 in 2013 and 2012, and $0.11 in 2011. Taxes other than income taxes per Mcfe vary from period to period due to changes in severance and ad valorem taxes that result from the mix of our production volumes and fluctuations in commodity prices.

Our full cost pool amortization rate averaged $1.08 per Mcfe for 2013, $1.31 per Mcfe for 2012 and $1.30 per Mcfe for 2011. The amortization rate is impacted by the timing and amount of reserve additions and the costs associated with those additions, revisions of previous reserve estimates due to both price and well performance, write-downs that result from full cost ceiling tests, proceeds from the sale of properties that reduce the full cost pool and the levels of costs subject to amortization. We cannot predict our future full cost pool amortization rate with accuracy due to the variability of each of the factors discussed above, as well as other factors, including but not limited to the uncertainty of the amount of future reserves attributed to our Fayetteville Shale and Marcellus Shale properties.

Unevaluated costs excluded from amortization were $956.5 million at the end of 2013 compared to $1,023.9 million at the end of 2012 and $942.9 million at the end of 2011. Unevaluated costs excluded from amortization at the end of 2013 included $72.3 million related to our properties in Canada. The decrease in unevaluated costs since December 31, 2012 primarily resulted from the move of certain New Ventures acreage to evaluated, slightly offset by our acquisition of Marcellus Shale acreage in the second quarter of 2013, which is still largely unevaluated. See Note 4 to the consolidated financial statements for additional information regarding our unevaluated costs excluded from amortization.

The timing and amount of production and reserve additions could have a material impact on our per unit costs; if production or reserves additions are lower than projected, our per unit costs could increase.

**Midstream Services**

| | For the year ended December 31, | | |
|---|---|---|---|
| | 2013 | 2012 | 2011 |
| | ($ in millions, except volumes) | | |
| Revenues – marketing | $ 2,830.4 | $ 1,889.5 | $ 2,451.3 |
| Revenues – gathering | $ 516.3 | $ 474.0 | $ 408.2 |
| Gas purchases – marketing | $ 2,782.9 | $ 1,858.8 | $ 2,418.1 |
| Operating costs and expenses | $ 238.4 | $ 210.4 | $ 193.4 |
| Operating income | $ 325.4 | $ 294.3 | $ 248.0 |
| Gas volumes marketed (Bcf) | 785.9 | 676.2 | 611.4 |
| Gas volumes gathered (Bcf) | 900.1 | 845.5 | 745.7 |

*Revenues*

Revenues from our marketing activities were up 50% to $2,830.4 million for 2013 compared to 2012. The increase in marketing revenues resulted from an increase in the prices received for volumes marketed and an increase in volumes marketed. Revenues from our marketing activities were down 23% to $1,889.5 million for 2012 compared to 2011. The decrease in marketing revenues for 2012 resulted from a decrease in the prices received for volumes marketed, which was partially offset by an increase in volumes marketed. The average price received for volumes marketed increased 29% in 2013 compared to 2012, and decreased 30% in 2012 compared to 2011. Volumes marketed increased 16% in 2013 compared to 2012, and increased 11% in 2012 compared to 2011. Of the total volumes marketed, production from our E&P operated wells accounted for 96% in 2013, 95% in 2012 and 94% in 2011. Increases and decreases in marketing revenues due to changes in commodity prices are largely offset by corresponding changes in natural gas purchase expenses.

Revenues from our gathering activities were up 9% to $516.3 million for 2013 compared to 2012, and were up 16% to $474.0 million for 2012 compared to 2011. The increases in gathering revenues primarily resulted from a 6% increase in natural gas volumes gathered in 2013 compared to 2012 and a 13% increase in natural gas volumes gathered in 2012 compared to 2011. The majority of the increases in gathering revenues for 2013 and 2012 resulted from increases in the volumes gathered from our operated production from the Marcellus Shale.

*Operating Income*

Operating income from our Midstream Services segment increased 11% to $325.4 million in 2013 and increased 19% to $294.3 million in 2012. The increases in operating income reflect the substantial increases in natural gas volumes gathered and marketed which resulted primarily from our increased E&P production volumes. The increase in operating income for 2013 compared to 2012 was due to an increase of $42.3 million in gathering revenues and $16.8 million in the margin generated from our natural gas marketing activities, which was partially offset by a $28.0 million increase in operating costs and expenses, exclusive of purchased natural gas costs, associated with the increase in natural gas volumes gathered. The increase in operating income for 2012 compared to 2011 was due to a $65.8 million increase in gathering revenues, which was partially offset by a decrease of $2.6 million in the margin generated from our natural gas marketing activities and a $17.0 million increase in operating costs and expenses, exclusive of purchased natural gas costs associated with the increase in natural gas volumes gathered.

The margin generated from natural gas marketing activities was $47.5 million for 2013, compared to $30.7 million for 2012 and $33.2 million for 2011. Margins are driven primarily by volumes of natural gas marketed and may fluctuate depending on the prices paid for commodities and the ultimate disposition of those commodities. The increases in margins generated are primarily the result of a 16% increase in volumes marketed in 2013 and an 11% increase in volumes marketed in 2012, as compared to prior years, resulting from marketing our increased E&P production volumes. We enter into hedging activities from time to time with respect to our natural gas marketing activities to provide margin protection. For more information about our derivatives and risk management activities, we refer you to “Quantitative and Qualitative Disclosures about Market Risk” and Note 5 to the consolidated financial statements for additional information.

**Interest Expense**

Interest expense, net of capitalization, was $41.6 million in 2013, an increase of $5.9 million compared to 2012, primarily due to our increased borrowing level. Interest capitalized was $62.8 million in 2013 compared to $62.1 million in 2012.

Interest expense, net of capitalization, was $35.7 million in 2012. The increase of $11.6 million compared to 2011 is primarily due to our increased borrowing level. Interest capitalized increased to $62.1 million in 2012 from $45.7 million in 2011 primarily due to an increase in our weighted average interest rate and an increase in our unevaluated properties during 2012.

**Income Taxes**

Our effective tax rate was 40.9%, 38.5%, and 39.3%, in 2013, 2012, and 2011, respectively. The effective tax rate was higher in 2013 primarily due to our increased development activities in the state of Pennsylvania, an increase in the impact of our state rates used in establishing deferred income taxes, and a valuation allowance placed against certain state net operating losses. The effective tax rate was lower in 2012 primarily due to the $1,939.7 million non-cash impairment of our natural gas and oil properties. In general, differences between our effective tax rate and the federal tax rate of 35% primarily result from the effect of certain state income taxes and permanent items attributable to book-tax differences.

## LIQUIDITY AND CAPITAL RESOURCES

We depend primarily on internally generated funds, our Credit Facility, sales of non-core assets and funds accessed through capital markets as our primary sources of liquidity.

During 2014, and depending on natural gas prices, we may draw on a portion of the funds available under our Credit Facility to fund the portion of our planned capital investments exceeding our operating cash flow (discussed below under "Capital Investments". We refer you to Note 8 to the consolidated financial statements included in this Form 10-K and the section below under "Financing Requirements" for additional discussion of our Credit Facility.

As of December 31, 2013, our capital structure consisted of 35% debt and 65% equity. We believe that our operating cash flow and available funds under our Credit Facility will be adequate to meet our capital and operating requirements for 2014. The credit status of the financial institutions participating in our Credit Facility could adversely impact our ability to borrow funds under the Credit Facility. Although we believe all of the lenders under the facility have the ability to provide funds, we cannot predict whether each will meet its obligation.

Net cash provided by operating activities increased 15% to $1.9 billion in 2013, due to an increase in net income adjusted for non-cash expenses which was partially offset by changes in working capital accounts. Net cash provided by operating activities decreased 5% to $1.7 billion in 2012 over 2011 due to a decrease in net income adjusted for non-cash expenses which was partially offset by changes in working capital accounts. For 2013, requirements for our capital investments were funded from our cash generated by operating activities, cash and cash equivalents, and net proceeds from borrowings under our Credit Facility. Net cash from operating activities provided 85% of our cash requirements for capital investments in 2013, 78% in 2012 and 80% in 2011.

Our cash flow from operating activities is highly dependent upon the market prices that we receive for our natural gas and oil production. Natural gas and oil prices are subject to wide fluctuations and are driven by market supply and demand factors, which are impacted by many factors. The sales price we receive for our production is also influenced by our commodity hedging activities. See risk factors in Item 1A for further details. Our commodity hedging activities are subject to the credit risk of our counterparties being financially unable to complete the transaction. We actively monitor the credit status of our counterparties, performing both quantitative and qualitative assessments based on their credit ratings and credit default swap rates where applicable, and to date have not had any credit defaults associated with our transactions. However, any future failures by one or more counterparties could negatively impact our cash flow from operating activities.

Additionally, our short-term cash flows are dependent on the timely collection of receivables from our customers and partners. We actively manage this risk through credit management activities and, through the date of this filing, have not experienced any significant write-offs for non-collectable amounts. However, any sustained inaccessibility of credit by our customers and partners could adversely impact our cash flows.

Due to the above factors, we are unable to forecast with certainty our future level of cash flow from operations. Accordingly, we will adjust our discretionary uses of cash dependent upon available cash flow.

**Capital Investments**

Our capital investments were $2.2 billion in 2013, compared to $2.1 billion in 2012 and $2.2 billion in 2011. Capital investments include a decrease of $24.9 million in 2013, a decrease of $36.9 million in 2012 and an increase of $4.3 million in 2011 related to the change in accrued expenditures between years. Our E&P segment investments in 2013 were $2.1 billion compared to $1.9 billion in 2012 and $2.0 billion in 2011.

| | Capital investments for the year ended December 31, | | | | | |
|---|---|---|---|---|---|---|
| | | **2013** | | 2012 | | 2011 |
| | | | | (in thousands) | | |
| Exploration and production | **$** | **2,052,148** | $ | 1,860,681 | $ | 1,977,493 |
| Midstream Services | **$** | **157,635** | $ | 164,978 | $ | 160,776 |
| Other | **$** | **25,014** | $ | 54,860 | $ | 68,905 |
| | | **2,234,797** | | 2,080,519 | | 2,207,174 |

Our capital investments for 2014 are planned to be $2.3 billion, consisting of approximately $2.0 billion for E&P, $140 million for Midstream Services and $150 million for corporate and other purposes. Of the approximately $2.0 billion, we expect to allocate approximately $900 million to our Fayetteville Shale properties and approximately $760 million to our Marcellus Shale properties. Our planned level of capital investments in 2014 is expected to allow us to continue our progress in the Fayetteville Shale and the Marcellus Shale programs and explore and develop other existing natural gas and oil properties and generate new drilling prospects. As discussed above, our 2014 capital investment program is expected to be funded through cash flow from operations and borrowings under our Credit Facility. The planned capital program for 2014 is flexible and can be modified. We will reevaluate our proposed investments as needed to take into account prevailing market conditions and, if natural gas prices change significantly in 2014, we could change our planned investments.

**Financing Requirements**

Our total debt outstanding was $1,951.3 million as of December 31, 2013, compared to $1,669.5 million at December 31, 2012.

In December 2013, the Company entered into a Credit Agreement ("Credit Facility"), that exchanged our previous revolving credit facility. Under the Credit Facility, we have a borrowing capacity of $2.0 billion. The Credit Facility has a maturity date of December 2018 and options for two one-year extensions with participating lender approval. The amount available under the Credit Facility may be increased by $500.0 million upon the Company's agreement with its participating lenders. The interest rate on the Credit Facility is calculated based upon our debt rating and is currently 150 basis points over the current London Interbank Offered Rate, or LIBOR. The borrowing rate on our previous revolving credit facility was 200 basis points over LIBOR as of December 31, 2012. The Credit Facility is unsecured and is not guaranteed by any subsidiaries of the Company. Contemporaneously with the execution of the Credit Agreement, in December 2013, the Company obtained releases of subsidiary guarantees under the 7.15%, 7.5%, 7.35%, 7.125% and 4.10% Senior Notes.

The interest rate on our Credit Facility is calculated based upon our public debt rating and is currently 150 basis points over LIBOR. At February 24, 2014, we have a long-term issuer credit rating of BBB- by Standard and Poor's and Fitch ratings and we have a long-term credit rating of Baa3 by Moody's. Any downgrades in our public debt ratings could increase our cost of funds under our Credit Facility.

Our Credit Facility contains covenants which impose certain restrictions on us. Under our Credit Facility, we must keep our total debt at or below 60% of our total adjusted book capital. This financial covenant with respect to capitalization percentages excludes the noncontrolling interest in equity, the effects of any non-cash impacts from any full cost ceiling impairments (beginning in the year ended December 31, 2011), certain non-cash hedging activities and our pension and other postretirement liabilities. Therefore, under our Credit Facility provision, our capital structure as of December 31, 2013 was 29% debt and 71% equity. We were in compliance with all of the covenants of our Credit Facility as of

December 31, 2013. Although we do not anticipate any violations of our financial covenant, our ability to comply with this covenant is dependent upon the success of our exploration and development program and upon factors beyond our control, such as the market prices for natural gas and oil. If we are unable to borrow under our Credit Facility, we may have to decrease our capital investment plans.

Our hedges allow us to ensure a certain level of cash flow to fund our operations. At February 24, 2014, we had NYMEX commodity price hedges in place on 455.8 Bcf, or approximately 61% of our targeted 2014 production and 119.5 Bcf of our targeted 2015 production. The amount of our debt will be dependent upon commodity prices and our capital investment plans.

**Off-Balance Sheet Arrangements**

We may enter into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations. As of December 31, 2013, the Company's material off-balance sheet arrangements and transactions include operating lease arrangements. There are no other transactions, arrangements or other relationships with unconsolidated entities or other persons that are reasonably likely to materially affect our liquidity or availability of our capital resources. For more information regarding off-balance sheet arrangements, we refer you to "Contractual Obligations and Contingent Liabilities and Commitments" below.

## Contractual Obligations and Contingent Liabilities and Commitments

We have various contractual obligations in the normal course of our operations and financing activities. Significant contractual obligations as of December 31, 2013, were as follows:

*Contractual Obligations*:

| | Payments Due by Period | | | | |
|---|---|---|---|---|---|
| | **Total** | Less than 1 Year | 1 to 3 Years | 3 to 5 Years | More than 5 Years |
| | | | (in thousands) | | |
| Transportation charges(1) | **$ 3,508,883** | $ 362,782 | $ 812,422 | $ 738,948 | $ 1,594,731 |
| Debt | **1,952,300** | 1,200 | 2,400 | 948,700 | 1,000,000 |
| Interest on senior notes | **572,187** | 90,986 | 181,714 | 155,987 | 143,500 |
| Operating leases(2) | **229,220** | 65,209 | 100,502 | 38,579 | 24,930 |
| Compression services(3) | **93,830** | 38,568 | 41,654 | 12,942 | 666 |
| Operating agreements(4) | **48,599** | 41,950 | 6,649 | - | - |
| Purchase obligations | **43,473** | 43,473 | - | - | - |
| Other obligations(5) | **481,777** | 91,816 | 31,889 | 13,797 | 344,275 |
| | **$ 6,930,269** | $ 735,984 | $ 1,177,230 | $ 1,908,953 | $ 3,108,102 |

(1) As of December 31, 2013, our Midstream Services segment had commitments for demand transportation charges on various pipelines, including approximately $751.8 million related to the FEP pipeline, $482.8 million related to the Boardwalk pipeline, $505.3 million related to the Constitution pipeline and $367.4 million related to the Tennessee Gas pipeline. Also, SEPCO had approximate commitments of $221.2 million related to the Bluestone Gathering pipeline and $767.2 million associated with Susquehanna Gathering Company I, LLC's construction of gathering infrastructure in Susquehanna County, Pennsylvania to provide gathering services to SES in support of a portion of our future Marcellus Shale natural gas production.

(2) Operating leases include costs for compressors, aircraft, vehicles, office space and equipment under non-cancelable operating leases expiring through 2027. Additionally, this includes $30.3 million for pressure pumping equipment for E&P operations through 2018. In 2014, we intend to enter into a long-term lease on our new corporate campus, upon the completion of the project.

(3) As of December 31, 2013, our Midstream Services segment had commitments of approximately $92.7 million and our E&P segment had commitments of approximately $1.2 million for compression services associated primarily with our Fayetteville Shale operations.

(4) As of December 31, 2013, our E&P segment had commitments for approximately $131.8 million to companies for fracture stimulation services, which are cancellable under certain circumstances and therefore are not included in the above table.

(5) In conjunction with our exploration program in New Brunswick, Canada, we provided promissory notes payable on demand to the Minister of Finance of the Province of New Brunswick with an aggregate principal amount of CAD $44.5 million. See Note 9 to the consolidated financial statements for additional information regarding our commitments related to our exploration program in Canada. Our other significant contractual obligations include approximately $380.9 million for asset retirement obligations primarily relating to oil and natural gas properties, approximately $38.1 million associated with the construction of our new corporate campus, approximately $12.4 million for funding of benefit plans, approximately $9.9 million for various information technology support and data subscription agreements, approximately $6.5 million for insurance premium financing and approximately $5.4 million related to seismic services.

We refer you to Note 8 to the consolidated financial statements for a discussion of the terms of our debt.

*Commitments and Contingent Liabilities*

Substantially all of our employees are covered by defined benefit and postretirement benefit plans. We currently expect to contribute approximately $12.0 million to our pension plans and $0.4 million to our postretirement benefit plan in 2014. For 2013, we contributed $12.5 million to our pension plans and contributed $0.1 million to our postretirement benefit plan. As of December 31, 2013 we recognized a liability of $16.2 million as a result of the underfunded status of our pension and other postretirement benefit plans compared to a liability of $33.5 million at December 31, 2012. For further information regarding our pension and other postretirement benefit plans, we refer you to Note 12 to the consolidated financial statements and "Critical Accounting Policies" below for additional information.

## Working Capital

We maintain access to funds that may be needed to meet capital requirements through our Credit Facility described in "Financing Requirements" above. We had negative working capital of $43.8 million as of December 31, 2013 and positive working capital of $41.1 million at December 31, 2012. Current assets decreased $164.7 million during 2013 primarily due to a $211.8 million decrease in our current derivative asset and a $39.2 million decrease in cash, cash equivalents, and restricted cash, which was partially offset by an $86.4 million increase in accounts receivable. Current liabilities decreased $79.8 million primarily due to an $81.8 million decrease in our current deferred income taxes related to our hedging activities and a $68.9 million decrease in advances from partners, which partially was offset by a $47.9 million increase in accounts payable, an $18.9 increase in other current liabilities, and a $5.0 million increase in taxes payable.

## CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The discussion and analysis of financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of these financial statements requires management to make estimates and judgments that affect the amounts of assets, liabilities, revenues and expenses and related disclosure of contingent assets and liabilities. We evaluate our estimates on an on-going basis, based on historical experience and on various other assumptions that are believed to be reasonable under the circumstances. Actual results may differ from these estimates under different assumptions or conditions. We believe the following describes significant judgments and estimates used in the preparation of our consolidated financial statements.

### Natural Gas and Oil Properties

We utilize the full cost method of accounting for costs related to the exploration, development and acquisition of natural gas and oil properties. Under this method, all such costs (productive and nonproductive), including salaries, benefits and other internal costs directly attributable to these activities are capitalized on a country-by-country basis and amortized over the estimated lives of the properties using the units-of-production method. These capitalized costs are subject to a ceiling test that limits such pooled costs, net of applicable deferred taxes, to the aggregate of the present value of future net revenues attributable to proved natural gas and oil reserves discounted at 10% (standardized measure) plus the lower of cost or market value of unproved properties. Any costs in excess of the ceiling are written off as a non-cash expense. The expense may not be reversed in future periods, even though higher natural gas and oil prices may subsequently increase the ceiling. Companies using the full cost method are required to use the average quoted price from the first day of each month from the previous 12 months, including the impact of derivatives qualifying as cash flow hedges, to calculate the ceiling value of their reserves.

Using the average quoted price from the first day of each month from the previous 12 months for Henry Hub natural gas of $3.67 per MMBtu, West Texas Intermediate oil of $93.42 per barrel, and NGLs of $43.45 per barrel, adjusted for market differentials, the Company's net book value of its United States natural gas and oil properties did not exceed the ceiling amount and did not result in a ceiling test impairment at December 31, 2013. Cash flow hedges of natural gas production in place increased this ceiling amount by approximately $70.7 million as of December 31, 2013. At December 31, 2012, the ceiling value of the Company's reserves was calculated based upon average quoted price from the first day of each month from the previous 12 months for Henry Hub natural gas of $2.76 per MMBtu for Henry Hub natural gas and West Texas Intermediate oil of $91.21 per barrel. At December 31, 2011, the ceiling value of the Company's reserves was calculated based upon average quoted price from the first day of each month from the previous 12 months for Henry Hub natural gas of $4.12 per MMBtu for Henry Hub natural gas and for West Texas Intermediate oil of $92.71. Using the first-day-of-the-month prices of natural gas for the first two months of 2014 and NYMEX strip prices for the remainder of 2014, as applicable, the prices required to be used to determine the ceiling limit is not expected to result in a ceiling test write-down in 2014. Decreases in market prices as well as changes in production rates, levels of reserves, evaluation of costs excluded from amortization, future development costs and production costs are not expected to result in future ceiling test impairments. During 2012, the net capitalized costs of our United States natural gas and oil properties exceeded the ceiling by approximately $1,192.4 million (net of tax) and resulted in a non-cash ceiling test impairment.

All of our costs directly associated with the acquisition and evaluation of properties in Canada as of December 31, 2013 were unproved and did not exceed the ceiling amount. If our exploration program in Canada is unsuccessful on all or a portion of these properties, a ceiling test impairment may result in the future.

Natural gas and oil reserves cannot be measured exactly. Our estimate of natural gas and oil reserves requires extensive judgments of reservoir engineering data and projections of cost that will be incurred in developing and producing reserves and is generally less precise than other estimates made in connection with financial disclosures. Our reservoir engineers prepare our reserve estimates under the supervision of our management. Reserve estimates are prepared for each of our properties annually by the reservoir engineers assigned to the asset management team to which the property is assigned. The reservoir engineering and financial data included in these estimates are reviewed by senior engineers who are not part of the asset management teams and our Manager – Capital Budgeting & Reserves, who was the technical person primarily responsible for the preparation of our reserve estimates, and has 12 years of experience in petroleum engineering, including the estimation of oil and natural gas reserves. He reports to our Executive Vice President – Corporate Development, who has more than 32 years of experience in reservoir engineering, including the estimation of oil and natural gas reserves in multiple basins, both in the United States and internationally. On our behalf, the Executive Vice President – Corporate Development engages NSAI, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies, to independently audit our proved reserves estimates as discussed in more detail below. The financial data included in the reserve estimates are also separately reviewed by our accounting staff. Following these reviews and the audit, the reserve estimates are submitted by our Executive Vice President – Corporate Development to our Chief Executive Officer for his review and approval prior to the presentation to our Board of Directors. NSAI reports the results of its reserve audit to the Board of Directors, with whom final authority over the estimates of our proved reserves rests.

Proved developed reserves generally have a higher degree of accuracy in this estimation process, when compared to proved undeveloped and proved non-producing reserves, as production history and pressure data over time is available for the majority of our proved developed properties. Proved developed reserves accounted for 61% of our total reserve base as of December 31, 2013. Assigning monetary values to such estimates does not reduce the subjectivity and changing nature of such reserve estimates. The uncertainties inherent in the reserve estimates are compounded by applying additional estimates of the rates and timing of production and the costs that will be incurred in developing and producing the reserves. We cannot assure you that our internal controls sufficiently address the numerous uncertainties and risks that are inherent in estimating quantities of natural gas and oil reserves and projecting future rates of production and timing of development expenditures as many factors are beyond our control. We refer you to "Although our estimated natural gas and oil reserve data is independently audited, our estimates may still prove to be inaccurate" in Item 1A, "Risk Factors," of Part I of this Form 10-K for a more detailed discussion of these uncertainties, risks and other factors.

In conducting its audit, the engineers and geologists of NSAI study our major properties in detail and independently develop reserve estimates. NSAI's audit consists primarily of substantive testing, which includes a detailed review of major properties that account for approximately 95% of the present worth of the company's total proved reserves. NSAI's audit process consists of sorting all fields by descending present value order and selecting the fields from highest value to descending value until the selected fields account for more than 80% of the present worth of our reserves. The properties in the bottom 20% of the total present worth are not reviewed in the audit. The fields included in approximately the top 95% present value as of December 31, 2013, accounted for approximately 97% of our total proved reserves and approximately 100% of our proved undeveloped reserves. In the conduct of its audit, NSAI did not independently verify the data we provided to them with respect to ownership interests, oil and natural gas production, well test data, historical costs of operation and development, product prices, or any agreements relating to current and future operations of the properties and sales of production. NSAI has advised us that if, in the course of its audit, something came to its attention that brought into question the validity or sufficiency of any such information or data, NSAI did not rely on such information or data until it had satisfactorily resolved any questions relating thereto or had independently verified such information or data. On February 6, 2014, NSAI issued its audit opinion as to the reasonableness of our reserve estimates for the year-ended December 31, 2013, stating that our estimated proved oil and natural gas reserves are, in the aggregate, reasonable and have been prepared in accordance with Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

A decline in natural gas and oil prices used to calculate the discounted future net revenues of our reserves affects both the present value of cash flows and the quantity of reserves. Our reserve base is nearly 100% natural gas, therefore changes in oil prices used do not have as significant an impact as natural gas prices on cash flows and reserve quantities. Our standardized measure and reserve quantities as of December 31, 2013, were $3,736.0 million and 6,976.3 Bcfe, respectively. An assumed decrease of $1.00 per Mcf in the average 2013 natural gas price used to price our reserves would have resulted in an approximate $1,672.4 million decline in our standardized measure and an approximate decrease of 1,545.9 Bcfe of our reserves. The unit of production rate for amortization is adjusted quarterly based on changes in reserve estimates, capitalized costs and future development costs.

**Hedging**

We use natural gas and oil swap agreements and options to reduce the volatility of earnings and cash flow due to fluctuations in the prices of natural gas and oil. Our policies prohibit speculation with derivatives and limit agreements to counterparties with appropriate credit standings to minimize the risk of uncollectability. We actively monitor the credit status of our counterparties, performing both quantitative and qualitative assessments based on their credit ratings and credit default swap rates where applicable, and to date have not had any credit defaults associated with our transactions. In 2011, 2012, and 2013 we hedged 52%, 47% and 44% of our production. The primary market risks related to our derivative contracts are the volatility in market prices and basis differentials for natural gas and oil. However, the market price risk is generally offset by the gain or loss recognized upon the related natural gas or oil transaction that is hedged.

Our derivative instruments are recorded at fair value in our financial statements and generally qualify for hedge accounting. We have established the fair value of derivative instruments using data provided by our counterparties in conjunction with assumptions evaluated internally using established index prices and other sources. These valuations are recognized as assets or liabilities in our balance sheet and, to the extent an open position is an effective cash flow hedge on equity production, the offset is recorded in other comprehensive income. Results of settled commodity hedging transactions are reflected in natural gas and oil sales. Any derivative not designated for hedge accounting treatment or any ineffective portion of a properly designated hedge is recognized immediately in earnings. As of December 31, 2013, our fixed price basis swaps and fixed price call options were not designated for hedge accounting treatment. Changes in the fair value of derivatives that were not designated as cash flow hedges are recorded in gain (loss) on derivatives. For the year ended December 31, 2013, we recorded a loss on derivatives of $26.3 million related to fixed price call options that were not designated for hedge accounting treatment, a gain on derivatives of $37.2 million related to fixed price swaps not designated for hedge accounting, and a gain on derivatives of $12.2 million related to the basis swaps that were not designated for hedge account treatment.

In general and without consideration of volatility or duration, if 2014 and 2015 natural gas prices increase from current levels, the Company will recognize losses in future periods and, likewise, if 2014 and 2015 natural gas prices decline from current levels, the Company will recognize gains in future periods on its derivative contracts not accounted for under hedge accounting prior to settlement. Future market price volatility could create significant changes to the hedge positions recorded in our financial statements. We refer you to “Quantitative and Qualitative Disclosures about Market Risk” in Item 7A of Part II of this Form 10-K for additional information regarding our hedging activities.

**Pension and Other Postretirement Benefits**

We record our prepaid or accrued benefit cost, as well as our periodic benefit cost, for our pension and other postretirement benefit plans using measurement assumptions that we consider reasonable at the time of calculation (see Note 12 to the consolidated financial statements for further discussion and disclosures regarding these benefit plans). Two of the assumptions that affect the amounts recorded are the discount rate, which estimates the rate at which benefits could be effectively settled, and the expected return on plan assets, which reflects the average rate of earnings expected on the funds invested. For the December 31, 2013 benefit obligation and periodic benefit cost to be recorded in 2014, the discount rate assumed is 5.00% and 4.00%, respectively. This compares to a discount rate of 4.00% and 5.00% for the benefit obligation and periodic benefit cost recorded in 2013, respectively. For the 2014 periodic benefit cost, the expected return assumed is 7.00%, compared to an expected return of 7.50% in 2013.

Using the assumed rates discussed above, we recorded total benefit cost of $16.3 million in 2013 related to our pension and other postretirement benefit plans. Due to the significance of the discount rate and expected long-term rate of return, the following sensitivity analysis demonstrates the effect that a 50 basis point change in those assumptions would have had on our 2013 pension expense:

| | Increase (Decrease) of Annual Pension Expense | |
|---|---|---|
| | 50 Basis Point Increase | 50 Basis Point Decrease |
| | (in thousands) | |
| Discount rate | $ (1,047) | $ 1,160 |
| Expected long-term rate of return | $ (438) | $ 438 |

As of December 31, 2013, we recognized a liability of $16.2 million, compared to $33.5 million at December 31, 2012, related to our pension and other postretirement benefit plans. During 2013, we also made cash payments totaling $12.6 million to fund our pension and other postretirement benefit plans. In 2014, we expect to make cash payments totaling $12.4 million to fund our pension and other postretirement benefit plans and recognize pension expense of $12.3 million and a postretirement benefit expense of $3.0 million.

**Asset Retirement Obligations**

The Company owns natural gas and oil properties, which require expenditures to plug and abandon the wells when reserves in the wells are depleted. An asset retirement obligation associated with the retirement of a tangible long-lived asset is recognized as a liability in the period incurred or when it becomes determinable, with an associated increase in the carrying amount of the related long-lived asset. The cost of the tangible asset, including the asset retirement cost, is depreciated over the useful life of the asset. The asset retirement obligation is recorded at its estimated fair value and accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value. The recognition of asset retirement obligations requires management to make assumptions that include estimated plugging and abandonment costs, timing of settlements, inflation rates and discount rate, all of which are subject to change.

**Stock-Based Compensation**

The Company accounts for stock-based compensation transactions using a fair value method and recognizes an amount equal to the fair value of the stock options and stock-based payment cost in either the consolidated statement of operations or capitalizes the cost into natural gas and oil properties or gathering systems included in property and equipment. Costs are capitalized when they are directly related to the acquisition, exploration and development activities of the Company's natural gas and oil properties or directly related to the construction of the Company's gathering systems. The Company uses models to determine fair value of stock-based compensation, which requires significant judgment with respect to forfeitures, volatility and other factors. If any of the assumptions change significantly, stock-based compensation expense for future grants may differ materially from that recorded in the current period.

**New Accounting Standards Implemented in this Report**

Refer to further discussion of our significant accounting policies in Note 1 to the consolidated financial statements of this Form 10-K.

## CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

All statements, other than historical fact or present financial information, may be deemed to be forward-looking statements within the meaning of Section 27A of the Securities Act and Section 21E of the Exchange Act. All statements that address activities, outcomes and other matters that should or may occur in the future, including, without limitation, statements regarding the financial position, business strategy, production and reserve growth and other plans and objectives for our future operations, are forward-looking statements. Although we believe the expectations expressed in such forward-looking statements are based on reasonable assumptions, such statements are not guarantees of future performance. We have no obligation and make no undertaking to publicly update or revise any forward-looking statements, except as may be required by law.

Forward-looking statements include the items identified in the preceding paragraph, information concerning possible or assumed future results of operations and other statements in this Form 10-K identified by words such as "anticipate," "project," "intend," "estimate," "expect," "believe," "predict," "budget," "projection," "goal," "plan," "forecast," "target" or similar expressions.

You should not place undue reliance on forward-looking statements. They are subject to known and unknown risks, uncertainties and other factors that may affect our operations, markets, products, services and prices and cause our actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by the forward-looking statements. In addition to any assumptions and other factors referred to specifically in connection with forward-looking statements, risks, uncertainties and factors that could cause our actual results to differ materially from those indicated in any forward-looking statement include, but are not limited to:

- the timing and extent of changes in market conditions and prices for natural gas and oil (including regional basis differentials);
- our ability to fund our planned capital investments;
- our ability to transport our production to the most favorable markets or at all;
- the timing and extent of our success in discovering, developing, producing and estimating reserves;
- the economic viability of, and our success in drilling, our large acreage position in the Fayetteville Shale overall as well as relative to other productive shale natural gas plays;
- the impact of government regulation, including any increase in severance or similar taxes, legislation relating to hydraulic fracturing, the climate and over the counter derivatives;
- the costs and availability of oilfield personnel, services and drilling supplies, raw materials, and equipment, including pressure pumping equipment and crews;
- our ability to determine the most effective and economic fracture stimulation
- our future acquisition or divestiture activities;

- the impact of the adverse outcome of any material litigation against us;
- the effects of weather;
- increased competition and regulation;
- the financial impact of accounting regulations and critical accounting policies;
- the comparative cost of alternative fuels;
- the different risks and uncertainties associated with Canadian exploration and production;
- conditions in capital markets, changes in interest rates and the ability of our lenders to provide us with funds as agreed;
- credit risk relating to the risk of loss as a result of non-performance by our counterparties; and
- any other factors listed in the reports we have filed and may file with the Securities and Exchange Commission ("SEC").

We caution you that forward-looking statements contained in this Form 10-K are subject to all of the risks and uncertainties, many of which are beyond our control, incident to the exploration for and development, production and sale of natural gas and oil. These risks include, but are not limited to, commodity price volatility, third-party interruption of sales to market, inflation, lack of availability of goods and services, environmental risks, drilling and other operating risks, regulatory changes, the uncertainty inherent in estimating proved natural gas and oil reserves and in projecting future rates of production and timing of development expenditures and the other risks described in Item 1A of Part I of this Form 10-K.

Estimates of our proved natural gas and oil reserves and the estimated future net revenues from such reserves in this Form 10-K are based upon various assumptions, including assumptions required by the SEC relating to natural gas and oil prices, drilling and operating expenses, capital investments, taxes and availability of funds. The process of estimating natural gas and oil reserves is complex. This process requires significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. Therefore, those estimates are inherently imprecise.

Actual future production, natural gas and oil prices, revenues, taxes, development costs, operating expenses and quantities of recoverable natural gas and oil reserves will most likely vary from those estimated. Such variances may be material. Any significant variance could materially affect the estimated quantities and present value of reserves set forth in this Form 10-K. Our properties may also be susceptible to hydrocarbon drainage from production by other operators on adjacent properties. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing natural gas and oil prices and other factors, many of which are beyond our control.

As of December 31, 2013, approximately 39% of our estimated proved reserves were proved undeveloped and 1% were proved developed non-producing. Proved undeveloped reserves and proved developed non-producing reserves, by their nature, are less certain than proved developed producing reserves. Estimates of reserves in the non-producing categories are nearly always based on volumetric calculations rather than the performance data used to estimate producing reserves. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. Recovery of proved developed non-producing reserves requires capital expenditures to recomplete into the zones behind pipe and is subject to the risk of a successful recompletion. Production revenues from proved undeveloped and proved developed non-producing reserves will not be realized, if at all, until sometime in the future.

The reserve data assumes that we will make significant capital investments to develop our reserves. Although we have prepared estimates of our natural gas and oil reserves and the costs associated with these reserves in accordance with industry standards, we cannot assure you that the estimated costs are accurate, that development will occur as scheduled or that the actual results will be as estimated.

You should not assume that the present value of future net cash flows referred to in this Form 10-K is the current fair value of our estimated natural gas and oil reserves. In accordance with SEC requirements, the estimated discounted future net cash flows from proved reserves are generally based on average prices over the preceding twelve months and costs as of the date of the estimate. Actual future prices and costs may be materially higher or lower than the average prices and costs as of the date of the estimate. Any changes in consumption by natural gas purchasers or in governmental regulations or taxation could also affect actual future net cash flows. The timing of both the production and the expenses from the development and production of natural gas and oil properties will affect the timing of actual future net cash flows from proved reserves and their present value. In addition, the 10% discount factor, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most accurate discount factor for our company.

Should one or more of the risks or uncertainties described above or elsewhere in this Form 10-K occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements. We specifically disclaim all responsibility to publicly update any information contained in a forward-looking statement or any forward-looking statement in its entirety and therefore disclaim any resulting liability for potentially related damages.

All forward-looking statements attributable to us are expressly qualified in their entirety by this cautionary statement.

## ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market risks relating to our operations result primarily from the volatility in commodity prices, basis differentials and interest rates, as well as credit risk concentrations. We use natural gas and oil fixed price swap agreements and fixed price options and interest rate swaps to reduce the volatility of earnings and cash flow due to fluctuations in the prices of natural gas and oil and in interest rates. Our Board of Directors has approved risk management policies and procedures to utilize financial products for the reduction of defined commodity price risk. Utilization of financial products for the reduction of interest rate risks is subject to the approval of our Board of Directors. These policies prohibit speculation with derivatives and limit swap agreements to counterparties with appropriate credit standings.

### Credit Risk

Our financial instruments that are exposed to concentrations of credit risk consist primarily of trade receivables and derivative contracts associated with commodities trading. Concentrations of credit risk with respect to receivables are limited due to the large number of our purchasers and their dispersion across geographic areas. No single purchaser accounted for greater than 10% of revenues as of December 31, 2013. See “Commodities Risk” below for discussion of credit risk associated with commodities trading.

### Interest Rate Risk

The following table presents the principal cash payments for our debt obligations and related weighted-average interest rates by expected maturity dates as of December 31, 2013. As of December 31, 2013, we had $1,669.4 million of debt with a weighted average interest rate of 5.45% and we had $282.9 million of borrowings under our Credit Facility with a weighted average interest rate of 1.64%. Interest rate swaps may be used to adjust interest rate exposures when deemed appropriate. We currently have an interest rate swap in effect related to interest rates on construction costs associated with the new corporate office complex construction.

| | Expected Maturity Date | | | | | | | Fair Value |
|---|---|---|---|---|---|---|---|---|
| | 2014 | 2015 | 2016 | 2017 | 2018 | Thereafter | Total | 12/31/13 |
| Fixed Rate | $ 1.2 | $ 1.2 | $ 1.2 | $ 41.2 | $ 624.6 | $ 1,000.0 | $ 1,669.4 | $ 1,795.9 |
| Average Interest Rate | 7.15 % | 7.15 % | 7.15 % | 7.21 % | 7.49 % | 4.10 % | 5.45 % | – |
| Variable Rate | – | – | – | – | 282.9 | – | 282.9 | 282.9 |
| Average Interest Rate | – | – | – | – | 1.64 % | – | 1.64 % | – |

### Commodities Risk

We use over-the-counter natural gas and oil-fixed price swap agreements and fixed price options to hedge sales of our production against the inherent price risks of adverse price fluctuations or locational pricing differences between a published index and the NYMEX futures market. These swaps and options include (1) transactions in which one party will pay a fixed price (or variable price) for a notional quantity in exchange for receiving a variable price (or fixed price) based on a published index (referred to as price swaps), (2) transactions in which parties agree to pay a price based on two different indices (referred to as basis swaps) and (3) the purchase and sale of index-related puts and calls (collars) that provide a “floor” price, below which the counterparty pays funds equal to the amount by which the price of the commodity is below the contracted floor, and a "ceiling" price above which we pay to the counterparty the amount by which the price of the commodity is above the contracted ceiling.

The primary market risks relating to our derivative contracts are the volatility in market prices and basis differentials for natural gas and oil. However, the market price risk is offset by the gain or loss recognized upon the related sale or purchase of the natural gas or sale of the oil that is hedged. Credit risk relates to the risk of loss as a result of non-performance by our counterparties. The counterparties are primarily major commercial banks, investment banks and integrated energy companies that management believes present minimal credit risks. The credit quality of each counterparty and the level of financial exposure we have to each counterparty are closely monitored to limit our credit risk exposure. Additionally, we perform both quantitative and qualitative assessments of these counterparties based on their credit ratings and credit default swap rates where applicable. We have not incurred any counterparty losses related to non-performance and do not anticipate any losses given the information we have currently. However, we cannot be certain that we will not experience such losses in the future.

*Exploration and Production*

The following table provides information about our financial instruments that are sensitive to changes in commodity prices and that are used to hedge prices for natural gas production. The table presents the notional amount in Bcf, the weighted average contract prices and the fair value by expected maturity dates.

| | Volume (Bcf) | Weighted Average Price to be Swapped ($/MMBtu) | Weighted Average Floor Price ($/MMBtu) | Weighted Average Ceiling Price ($/MMBtu) | Weighted Average Basis Differential ($/MMBtu) | Fair value at December 31, 2013 ($ in millions) |
|---|---|---|---|---|---|---|
| **Natural Gas (Bcf):** | | | | | | |
| Fixed Price Swaps: | | | | | | |
| 2014 | 382.3 | $ 4.33 | $ – | $ – | $ – | $ 53.9 |
| Basis Swaps: | | | | | | |
| 2014 | 21.3 | $ – | $ – | $ – | $ 0.01 | $ 11.4 |
| 2015 | 0.9 | $ – | $ – | $ – | $ 0.17 | $ 0.1 |
| Fixed Price Call Options: | | | | | | |
| 2015 | 199.8 | $ – | $ 5.09 | $ – | $ – | $ (30.4) |

As of December 31, 2013, our fixed price basis swaps and fixed price call options were not designated for hedge accounting treatment. Changes in the fair value of derivatives that were not designated as cash flow hedges are recorded in gain (loss) on derivatives. For the year ended December 31, 2013, we recorded a loss on derivatives of $26.3 million related to fixed price call options that were not designated for hedge accounting treatment, a gain on derivatives of $37.2 million related to fixed price swaps not designated for hedge accounting, a gain on derivatives of $12.2 million related to the basis swaps that were not designated for hedge account treatment, and a loss of $1.7 million related to the change in estimated ineffectiveness of our cash flow hedges. Typically, our hedge ineffectiveness results from changes at the end of a reporting period in the price differentials between the index price of the derivative contract, which is primarily a NYMEX price, and the index price for the point of sale for the cash flow that is being hedged.

Additionally, at December 31, 2012, we had outstanding fixed price basis differential swaps on 30.1 Bcf of 2013 and 9.1 Bcf of 2014 natural gas production.

## ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

## INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

## Management's Report on Internal Control Over Financial Reporting

It is the responsibility of the management of Southwestern Energy to establish and maintain adequate internal control over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934). Management has assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2013, utilizing the Committee of Sponsoring Organizations of the Treadway Commission's *Internal Control—Integrated Framework (1992)*.

Based on this evaluation, management concluded the Company's internal control over financial reporting was effective as of December 31, 2013.

The effectiveness of our internal control over financial reporting as of December 31, 2013 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in its report which appears herein.

## Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of Southwestern Energy Company

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Southwestern Energy Company and its subsidiaries at December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on criteria established in *Internal Control - Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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 (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) 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 (iii) 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.

/s/PRICEWATERHOUSECOOPERS LLP

Houston, TX
February 27, 2014

**SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES**

**CONSOLIDATED STATEMENTS OF OPERATIONS**

| | For the years ended December 31 | | |
|---|---|---|---|
| | **2013** | 2012 | 2011 |
| | (in thousands, except share/per share amounts) | | |
| **Operating Revenues:** | | | |
| Gas sales | **$ 2,381,478** | $ 1,956,311 | $ 2,078,151 |
| Gas marketing | **792,165** | 591,528 | 714,123 |
| Oil sales | **16,420** | 8,427 | 9,085 |
| Gas gathering | **181,082** | 173,727 | 149,973 |
| | **3,371,145** | 2,729,993 | 2,951,332 |
| **Operating Costs and Expenses:** | | | |
| Gas purchases – midstream services | **781,626** | 592,466 | 709,091 |
| Operating expenses | **328,503** | 244,735 | 240,944 |
| General and administrative expenses | **191,310** | 175,147 | 158,041 |
| Depreciation, depletion and amortization | **786,612** | 810,953 | 704,511 |
| Impairment of natural gas and oil properties | **–** | 1,939,734 | – |
| Taxes, other than income taxes | **79,471** | 67,584 | 65,518 |
| | **2,167,522** | 3,830,619 | 1,878,105 |
| **Operating Income (Loss)** | **1,203,623** | (1,100,626) | 1,073,227 |
| **Interest Expense:** | | | |
| Interest on debt | **100,051** | 93,296 | 65,421 |
| Other interest charges | **4,355** | 4,454 | 4,306 |
| Interest capitalized | **(62,812)** | (62,093) | (45,652) |
| | **41,594** | 35,657 | 24,075 |
| **Other Income, Net** | **2,207** | 1,030 | 264 |
| **Gain (Loss) on Derivatives** | **26,141** | (14,950) | 1,574 |
| **Income (Loss) Before Income Taxes** | **1,190,377** | (1,150,203) | 1,050,990 |
| **Provision (Benefit) for Income Taxes:** | | | |
| Current | **(11,071)** | 18,689 | 4,198 |
| Deferred | **497,945** | (461,828) | 409,023 |
| | **486,874** | (443,139) | 413,221 |
| **Net Income (Loss)** | **$ 703,503** | $ (707,064) | $ 637,769 |
| **Earnings (Loss) Per Share:** | | | |
| Basic | **$ 2.01** | $ (2.03) | $ 1.84 |
| Diluted | **$ 2.00** | $ (2.03) | $ 1.82 |
| **Weighted Average Common Shares Outstanding:** | | | |
| Basic | **350,465,430** | 348,610,503 | 347,205,316 |
| Effect of: | | | |
| Stock Options | **377,626** | – | 2,475,053 |
| Restricted Stock Awards | **258,396** | – | 241,044 |
| Diluted | **351,101,452** | 348,610,503 | 349,921,413 |

The accompanying notes are an integral part of these consolidated financial statements.

## SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
## CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

| | For the years ended December 31, | | |
|---|---|---|---|
| | **2013** | 2012 | 2011 |
| | | (in thousands) | |
| Net income (loss) | $ **703,503** | $ (707,064) | $ 637,769 |
| Change in derivatives: | | | |
| Reclassification to earnings [(1)] | **(185,506)** | (382,156) | (194,693) |
| Ineffectiveness [(2)] | **991** | (1,474) | 2,518 |
| Change in fair value of derivative instruments [(3)] | **21,619** | 130,935 | 520,552 |
| Total change in derivatives | **(162,896)** | (252,695) | 328,377 |
| Change in value of pension and other postretirement liabilities: | | | |
| Current period net gain (loss) [(4)] | **11,673** | (7,466) | (4,129) |
| Less: amortization of prior service cost included in net periodic pension cost [(5)] | **1,080** | 1,008 | 766 |
| Total change in value of pension and other postretirement liabilities | **12,753** | (6,458) | (3,363) |
| Change in currency translation adjustment | **(4,003)** | 529 | (561) |
| Comprehensive income (loss) | $ **549,357** | $ (965,688) | $ 962,222 |

(1) Net of ($123.7), ($249.4), and ($126.6) million in taxes for the years ended December 31, 2013, 2012 and 2011, respectively.

(2) Net of $0.7, ($1.0), and $1.6 million in taxes for the years ended December 31, 2013, 2012 and 2011, respectively.

(3) Net of $16.3, $85.1, and $338.4 million in taxes for the years ended December 31, 2013, 2012 and 2011, respectively.

(4) Net of $7.5, ($4.9), and ($2.7) million in taxes for the years ended December 31, 2013, 2012 and 2011, respectively.

(5) Net of $0.7, $0.7, and $0.5 million in taxes for the years ended December 31, 2013, 2012, and 2011, respectively.

The accompanying notes are an integral part of these consolidated financial statements.

## SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES

## CONSOLIDATED BALANCE SHEETS

| | December 31, 2013 | December 31, 2012 |
|---|---|---|
| | (in thousands) | |
| **ASSETS** | | |
| Current assets: | | |
| Cash and cash equivalents | $ **22,938** | $ 53,583 |
| Restricted cash | **–** | 8,542 |
| Accounts receivable | **464,045** | 377,638 |
| Inventories | **37,745** | 28,141 |
| Derivative asset | **70,871** | 282,693 |
| Other current assets | **48,576** | 58,315 |
| Total current assets | **644,175** | 808,912 |
| Natural gas and oil properties, using the full cost method, including $956.5 million in 2013 and $1,023.9 million in 2012 excluded from amortization | **13,293,841** | 11,283,114 |
| Gathering systems | **1,306,074** | 1,148,261 |
| Other | **702,544** | 597,064 |
| Less: Accumulated depreciation, depletion and amortization | **(8,005,836)** | (7,191,463) |
| Total property and equipment, net | **7,296,623** | 5,836,976 |
| Other long-term assets | **106,928** | 91,639 |
| TOTAL ASSETS | $ **8,047,726** | $ 6,737,527 |
| **LIABILITIES AND EQUITY** | | |
| Current liabilities: | | |
| Accounts payable | $ **507,468** | $ 459,569 |
| Taxes payable | **68,019** | 62,980 |
| Interest payable | **33,485** | 34,431 |
| Advances from partners | **–** | 68,919 |
| Current deferred income taxes | **24,353** | 106,123 |
| Other current liabilities | **54,686** | 35,749 |
| Total current liabilities | **688,011** | 767,771 |
| Long-term debt | **1,950,096** | 1,668,273 |
| Deferred income taxes | **1,532,329** | 1,049,138 |
| Pension and other postretirement liabilities | **15,823** | 33,174 |
| Other long-term liabilities | **239,437** | 183,299 |
| Total long-term liabilities | **3,737,685** | 2,933,884 |
| Commitments and contingencies | | |
| Equity: | | |
| Common stock, $0.01 par value; authorized 1,250,000,000 shares; issued 352,938,584 shares in 2013 and 351,100,391 in 2012 | **3,529** | 3,511 |
| Additional paid-in capital | **970,524** | 934,939 |
| Retained earnings | **2,652,653** | 1,949,150 |
| Accumulated other comprehensive income (loss) | **(4,342)** | 149,804 |
| Common stock in treasury, 9,924 shares in 2013 and 64,715 in 2012 | **(334)** | (1,532) |
| Total equity | **3,622,030** | 3,035,872 |
| TOTAL LIABILITIES AND EQUITY | $ **8,047,726** | $ 6,737,527 |

The accompanying notes are an integral part of these consolidated financial statements.

**SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES**
**CONSOLIDATED STATEMENTS OF CASH FLOWS**

| | For the twelve months ended December 31, | | |
|---|---|---|---|
| | **2013** | 2012 | 2011 |
| | | (in thousands) | |
| **Cash Flows From Operating Activities** | | | |
| Net income (loss) | $ **703,503** | $ (707,064) | $ 637,769 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | |
| Depreciation, depletion and amortization | **790,553** | 814,710 | 707,966 |
| Impairment of natural gas and oil properties | **–** | 1,939,734 | – |
| Deferred income taxes | **497,945** | (461,828) | 409,023 |
| (Gain) loss on derivatives, net of settlement | **(21,380)** | 2,154 | (5,600) |
| Stock-based compensation | **13,270** | 11,795 | 10,550 |
| Other | **(91)** | (619) | 6,310 |
| Change in assets and liabilities: | | | |
| Accounts receivable | **(86,134)** | (35,717) | 9,659 |
| Inventories | **(5,851)** | 18,111 | (12,975) |
| Accounts payable | **74,229** | 41,275 | 11,490 |
| Taxes payable | **5,040** | 22,289 | (9,360) |
| Interest payable | **(377)** | 5,058 | 610 |
| Advances from partners | **(68,918)** | (15,163) | 2,377 |
| Tax benefit for stock-based compensation | **–** | – | (14,626) |
| Other assets and liabilities | **6,739** | 19,207 | (13,376) |
| Net cash provided by operating activities | **1,908,528** | **1,653,942** | 1,739,817 |
| **Cash Flows From Investing Activities** | | | |
| Capital investments | **(2,252,647)** | (2,107,755) | (2,184,474) |
| Proceeds from sale of property and equipment | **18,163** | 201,101 | 154,526 |
| Transfers to restricted cash | **8,542** | (167,788) | (85,055) |
| Transfers from restricted cash | **–** | 159,246 | 85,055 |
| Other | **10,166** | 8,519 | 5,158 |
| Net cash used in investing activities | **(2,215,776)** | (1,906,677) | (2,024,790) |
| **Cash Flows From Financing Activities** | | | |
| Payments on current portion of long-term debt | **(1,200)** | (1,200) | (1,200) |
| Payments on revolving long-term debt | **(3,147,750)** | (2,263,900) | (3,445,900) |
| Borrowings under revolving long-term debt | **3,430,650** | 1,592,400 | 3,696,200 |
| Change in bank drafts outstanding | **(7,174)** | (35,608) | 24,637 |
| Proceeds from issuance of long-term debt | **–** | 998,780 | – |
| Debt issuance costs | **–** | (8,339) | – |
| Credit Facility costs | **(6,150)** | – | (10,211) |
| Proceeds from exercise of common stock options | **9,801** | 9,184 | 6,412 |
| Tax benefit for stock-based compensation | **–** | – | 14,626 |
| Other | **(978)** | (428) | (261) |
| Net cash provided by financing activities | **277,199** | 290,889 | 284,303 |
| Effect of exchange rate changes on cash | **(596)** | (198) | 242 |
| Increase (decrease) in cash and cash equivalents | **(30,645)** | 37,956 | (428) |
| Cash and cash equivalents at beginning of year | **53,583** | 15,627 | 16,055 |
| Cash and cash equivalents at end of period | $ **22,938** | $ 53,583 | $ 15,627 |

The accompanying notes are an integral part of these consolidated financial statements.

**SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES**
**CONSOLIDATED STATEMENT OF CHANGES IN EQUITY**

| | Southwestern Energy Stockholders | | | | | | |
|---|---|---|---|---|---|---|---|
| | Common Stock | | | | | | |
| | Shares Issued | Amount | Additional Paid-In Capital | Retained Earnings | Accumulated Other Comprehensive Income (Loss) | Common Stock in Treasury | **Total** |
| | | | | (in thousands) | | | |
| Balance at December 31, 2010 | 347,734 | $ 3,477 | $ 862,423 | $ 2,018,445 | $ 83,975 | $ (3,444) | $ **2,964,876** |
| Comprehensive income: | | | | | | | |
| Net income | – | – | – | 637,769 | – | – | **637,769** |
| Other comprehensive income | – | – | – | – | 324,453 | – | **324,453** |
| Total comprehensive income | – | – | – | – | – | – | **962,222** |
| Tax benefit for stock-based compensation | – | – | 14,626 | – | – | – | **14,626** |
| Stock-based compensation | – | – | 19,036 | – | – | – | **19,036** |
| Exercise of stock options | 851 | 9 | 6,403 | – | – | – | **6,412** |
| Issuance of restricted stock | 532 | 5 | (5) | – | – | – | **–** |
| Cancellation of restricted stock | (52) | – | 1 | – | – | – | **1** |
| Tax withholding – stock compensation | (7) | – | (262) | – | – | – | **(262)** |
| Issuance of stock awards | 1 | – | 42 | – | – | – | **42** |
| Treasury stock – non-qualified plan | – | – | 1,135 | – | – | 1,216 | **2,351** |
| Balance at December 31, 2011 | 349,059 | $ 3,491 | $ 903,399 | $ 2,656,214 | $ 408,428 | $ (2,228) | **$ 3,969,304** |
| Comprehensive loss: | | | | | | | |
| Net loss | – | – | – | (707,064) | – | – | **(707,064)** |
| Other comprehensive loss | – | – | – | – | (258,624) | – | **(258,624)** |
| Total comprehensive loss | – | – | – | – | – | – | **(965,688)** |
| Stock-based compensation | – | – | 22,212 | – | – | – | **22,212** |
| Exercise of stock options | 1,607 | 16 | 9,168 | – | – | – | **9,184** |
| Issuance of restricted stock | 539 | 5 | (5) | – | – | – | **–** |
| Cancellation of restricted stock | (95) | (1) | 1 | – | – | – | **–** |
| Tax withholding – stock compensation | (11) | – | (393) | – | – | – | **(393)** |
| Issuance of stock awards | 1 | – | 44 | – | – | – | **44** |
| Treasury stock – non-qualified plan | – | – | 513 | – | – | 696 | **1,209** |
| Balance at December 31, 2012 | 351,100 | $ 3,511 | $ 934,939 | $ 1,949,150 | $ 149,804 | $ (1,532) | **$ 3,035,872** |
| Comprehensive income: | | | | | | | |
| Net income | – | – | – | 703,503 | – | – | **703,503** |
| Other comprehensive loss | – | – | – | – | (154,146) | – | **(154,146)** |
| Total comprehensive income | – | – | – | – | – | – | **549,357** |
| Stock-based compensation | – | – | 25,502 | – | – | – | **25,502** |
| Exercise of stock options | 834 | 8 | 10,088 | – | – | – | **10,096** |
| Issuance of restricted stock | 1,103 | 11 | (11) | – | – | – | **–** |
| Cancellation of restricted stock | (74) | (1) | 1 | – | – | – | **–** |
| Tax withholding – stock compensation | (25) | – | (978) | – | – | – | **(978)** |
| Issuance of stock awards | 1 | – | 49 | – | – | – | **49** |
| Treasury stock – non-qualified plan | – | – | 934 | – | – | 1,198 | **2,132** |
| Balance at December 31, 2013 | 352,939 | $ 3,529 | $ 970,524 | $ 2,652,653 | $ (4,342) | $ (334) | **$ 3,622,030** |

The accompanying notes are an integral part of these consolidated financial statements.

## (1) ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

### *Nature of Operations*

Southwestern Energy Company (including its subsidiaries, collectively, "Southwestern" or the "Company") is an independent energy company engaged in natural gas and oil exploration, development and production. The Company engages in natural gas and oil exploration and production, natural gas gathering and natural gas marketing through its subsidiaries. Southwestern's exploration, development and production ("E&P") activities are principally focused within the United States on development of an unconventional gas reservoir in Arkansas, known as the Fayetteville Shale, in Pennsylvania, where we are targeting the unconventional gas reservoir known as the Marcellus Shale, and to a lesser extent in Texas, Arkansas, and Oklahoma in the Arkoma Basin. We have commenced exploration operations in Arkansas and Louisiana testing an unconventional oil play targeting the Lower Smackover Brown Dense. In 2010, we commenced an exploration program in New Brunswick, Canada, which represents our first operations outside of the United States. Southwestern's natural gas gathering and marketing (Midstream Services) activities primarily support the Company's E&P activities in Arkansas, Pennsylvania and Texas.

### *Basis of Presentation*

The consolidated financial statements included in this Annual Report on Form 10-K present the Company's financial position, results of operations and cash flows for the periods presented in accordance with accounting principles generally accepted in the United States ("GAAP"). The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the amounts of assets and liabilities and disclosure of contingent assets and liabilities, if any, at the date of the financial statements, and the amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. The Company evaluates subsequent events through the date the financial statements are issued.

Certain reclassifications have been made to the prior year's financial statements to conform to the 2013 presentation. The effects of the reclassifications were not material to the Company's consolidated financial statements.

### *Principles of Consolidation*

The consolidated financial statements include the accounts of Southwestern and its wholly owned subsidiaries. All significant intercompany accounts and transactions have been eliminated.

### *Revenue Recognition*

*Natural gas and oil sales.* Natural gas sales and oil sales are recognized when the products are sold to a purchaser at a fixed or determinable price, delivery has occurred, title has transferred and collectability of the revenue is reasonably assured. The Company uses the entitlement method that requires revenue recognition for the Company's net revenue interest of sales from its properties. Accordingly, natural gas sales and oil sales are not recognized for deliveries in excess of the Company's net revenue interest, while natural gas sales and oil sales are recognized for any under delivered volumes. Production imbalances are generally recorded at estimated sales prices of the anticipated future settlements of the imbalances. As of December 31, 2013, the Company had overproduction of 11.2 Bcf valued at $37.9 million and underproduction of 12.5 Bcf valued at $38.5 million. At December 31, 2012, the Company had overproduction of 8.4 Bcf valued at $28.4 million and underproduction of 9.4 Bcf valued at $29.9 million.

*Gas marketing.* The Company generally markets its natural gas, as well as some gas produced by third parties, to brokers, local distribution companies and end-users, pursuant to a variety of contracts. Gas marketing revenues are recognized when delivery of natural gas has occurred, title has transferred, the price is fixed or determinable and collectability of the revenue is reasonably assured.

*Gas gathering.* In certain areas the Company gathers its natural gas, as well as some natural gas produced by third parties, pursuant to a variety of contracts. Gas gathering revenues are recognized when the service is performed, the price is fixed or determinable and collectability of the revenue is reasonably assured.

*Other.* The Company maintains an underground gas storage facility and generally sells natural gas from its storage facility during the winter gas withdrawal season. Revenue is recognized on natural gas storage sales when the natural gas is sold to a purchaser at a fixed or determinable price, delivery has occurred, title has transferred and collectability of the revenue is reasonably assured. Other revenues, a component of gas sales, include a gain of $1.0 million in 2013, and losses of $0.9 million in 2012 and 2011, respectively, primarily related to the sale of natural gas in underground storage.

***Cash and Cash Equivalents***

Cash and cash equivalents are defined by the Company as short-term, highly liquid investments that have an original maturity of three months or less and deposits in money market mutual funds that are readily convertible into cash. Management considers cash and cash equivalents to have minimal credit and market risk.

Certain of the Company's cash accounts are zero-balance controlled disbursement accounts that do not have the right of offset against the Company's other cash balances. The Company presents the outstanding checks written against these zero-balance accounts as a component of accounts payable in the accompanying consolidated balance sheets. Outstanding checks included as a component of accounts payable totaled $4.9 million and $12.1 million as of December 31, 2013 and 2012, respectively.

***Restricted Cash***

Restricted cash represents proceeds deposited by the Company with a qualified intermediary to facilitate like-kind exchange transactions pursuant to Section 1031 of the Internal Revenue Code.

***Inventory***

Inventory recorded in current assets includes $3.7 million as of December 31, 2013 and $5.6 million at December 31, 2012, for natural gas in underground storage owned by the Company's E&P segment, and $34.1 million as of December 31, 2013 and $22.5 million at December 31, 2012 for tubulars and other equipment used in the E&P segment.

The Company has one natural gas storage facility. The current portion of the natural gas classified in inventory and carried at the lower of cost or market totaled $3.7 million as of December 31, 2013. The non-current portion of the natural gas classified in property and equipment and carried at cost totaled $16.0 million as of December 31, 2013. The carrying value of the non-current natural gas is evaluated for recoverability whenever events or changes in circumstances indicate that it may not be recoverable. Withdrawals of current natural gas in underground storage are accounted for by a weighted average cost method whereby natural gas withdrawn from storage is relieved at the weighted average cost of current natural gas remaining in the facility.

Other assets include $15.1 million as of December 31, 2013 and $13.8 million at December 31, 2012 for inventory held by the Midstream Services segment consisting primarily of pipe that will be used to construct gathering systems.

Tubulars and other equipment are carried at the lower of cost or market and are accounted for by a moving weighted average cost method that is applied within specific classes of inventory items. Purchases of inventory are recorded at cost and inventory is relieved at the weighted average cost of items remaining within a specified class.

***Property, Depreciation, Depletion and Amortization***

*Natural Gas and Oil Properties.* The Company utilizes the full cost method of accounting for costs related to the exploration, development and acquisition of natural gas and oil properties. Under this method, all such costs (productive and nonproductive), including salaries, benefits and other internal costs directly attributable to these activities are capitalized on a country by country basis and amortized over the estimated lives of the properties using the units-of-production method. These capitalized costs, less accumulated amortization and related deferred income taxes, are subject to a ceiling test that limits such pooled costs to the aggregate of the present value of future net revenues attributable to proved natural gas and oil reserves discounted at 10% plus the lower of cost or market value of unproved properties. Any costs in excess of the ceiling are written off as a non-cash expense. The expense may not be reversed in future periods, even though higher natural gas and oil prices may subsequently increase the ceiling. Full cost companies must use the average quoted price from the first day of each month from the previous 12 months, including the impact of derivatives qualifying as cash flow hedges, to calculate the ceiling value of their reserves.

Using the average quoted price from the first day of each month from the previous 12 months for Henry Hub natural gas of $3.67 per MMBtu, West Texas Intermediate oil of $93.42 per barrel, and NGLs of $43.45 per barrel, adjusted for market differentials, the Company's net book value of its United States natural gas and oil properties did not exceed the ceiling amount and did not result in a ceiling test impairment at December 31, 2013. Cash flow hedges of natural gas production in place increased this ceiling amount by approximately $70.7 million, net of tax, as of December 31, 2013. At December 31, 2012, the ceiling value of the Company's reserves was calculated based upon the average quoted price from the first day of each month from the previous 12 months for Henry Hub natural gas of $2.76 per MMBtu for Henry Hub natural gas and West Texas Intermediate oil of $91.21 per barrel. At December 31, 2011, the ceiling value of the Company's reserves was calculated based upon average quoted price from the first day of each month from the previous 12 months for Henry Hub natural gas of $4.12 per MMBtu for Henry Hub natural gas and for West Texas Intermediate oil of $92.71. Using the first-day-of-the-month prices of natural gas for the first two months of 2014 and NYMEX strip prices for the remainder of 2014, as applicable, the prices required to be used to determine the ceiling limit is not expected to result in a ceiling test write-down in 2014. Decreases in market prices as well as changes in production rates, levels of reserves, evaluation of costs excluded from amortization, future development costs and production costs could result in future ceiling test impairments. During 2012, the net capitalized costs of our natural gas and oil properties exceeded the ceiling by approximately $1,192.4 million (net of tax) and resulted in a non-cash ceiling test impairment.

All of our costs directly associated with the acquisition and evaluation of properties in Canada relating to our exploration program as of December 31, 2013 and as of December 31, 2012 were unproved and did not exceed the ceiling amount. If our exploration program in Canada is unsuccessful on all or a portion of these properties, or if further extensions are not granted, if requested, a ceiling test impairment may result in the future.

*Gathering Systems.* The Company's investment in gathering systems is primarily related to its Fayetteville Shale assets in Arkansas and the Marcellus Shale assets in Pennsylvania. These assets are being depreciated on a straight-line basis over 25 years.

*Capitalized Interest.* Interest is capitalized on the cost of unevaluated natural gas and oil properties that are excluded from amortization and actively being evaluated.

*Asset Retirement Obligations.* An asset retirement obligation associated with the retirement of a tangible long-lived asset is recognized as a liability in the period incurred or when it becomes determinable, with an associated increase in the carrying amount of the related long-lived asset. The cost of the tangible asset, including the asset retirement cost, is depreciated over the useful life of the asset. The asset retirement obligation is recorded at its estimated fair value and accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value. The Company owns natural gas and oil properties, which require expenditures to plug and abandon the wells and reclaim the associated pads when reserves in the wells are depleted.

***Income Taxes***

The Company follows the asset and liability method of accounting for income taxes. Under this method, deferred tax assets and liabilities are recorded for the estimated future tax consequences attributable to the differences between the financial carrying amounts of existing assets and liabilities and their respective tax basis. Deferred tax assets and liabilities are measured using the tax rate in effect for the year in which those temporary differences are expected to reverse. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in the year of the enacted rate change. Deferred income taxes are provided to recognize the income tax effect of reporting certain transactions in different years for income tax and financial reporting purposes. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized.

The Company accounts for uncertainty in income taxes using a recognition and measurement threshold for tax positions taken or expected to be taken in a tax return. The tax benefit from an uncertain tax position is recognized when it is more likely than not that the position will be sustained upon examination by taxing authorities based on technical merits of the position. The amount of the tax benefit recognized is the largest amount of the benefit that has a greater than 50% likelihood of being realized upon ultimate settlement. The effective tax rate and the tax basis of assets and liabilities reflect management's estimates of the ultimate outcome of various tax uncertainties.

***Derivative Financial Instruments***

The Company uses derivative financial instruments to manage defined commodity price risks and does not use them for speculative trading purposes. The Company uses commodity fixed price swaps and fixed price options contracts to hedge sales of natural gas. Gains and losses resulting from the settlement of hedge contracts have been recognized in gas sales if designated for hedge accounting treatment or gain (loss) on derivative if not designated for hedge accounting treatment in the consolidated statements of operations when the contracts expire and the related physical transactions of the commodity hedged are recognized. Changes in the fair value of derivative instruments designated as cash flow hedges and not settled are included in other comprehensive income (loss) to the extent that they are effective in offsetting the changes in the cash flows of the hedged item. In contrast, gains and losses from the ineffective portion of fixed price swaps designated for hedge accounting treatment are recognized currently in gas sales in the consolidated statement of operations. Gains and losses from the ineffective portion of fixed price swaps not designated for hedge accounting treatment, interest rate swaps, fixed price call options, and basis swaps that were not designated for hedge accounting treatment are recognized in gain (loss) on derivatives in the consolidated statement of operations. Changes in the fair value of derivative instruments designated as fair value hedges as well as the offsetting gain or loss on the hedged item are recognized in earnings immediately. See Note 5 and Note 7 for a discussion of the Company's hedging activities.

### *Earnings Per Share*

Basic earnings per common share is computed by dividing net income (loss) attributable to Southwestern by the weighted average number of common shares outstanding during each year. The diluted earnings per share calculation adds to the weighted average number of common shares outstanding the incremental shares that would have been outstanding assuming the exercise of dilutive stock options and the vesting of unvested restricted shares of common stock. Antidilutive is an increase in earnings per share or reduction in net loss per share resulting from the conversion, exercise, or contingent issuance of certain securities, as defined by GAAP.

For the year ended December 31, 2013, outstanding options for 1,569,665 shares with an average exercise price of $28.03 were included in the calculation of diluted shares. Options for 1,634,695 shares were excluded from the calculation because they would have had an antidilutive effect. As we recognized a net loss for the year ended December 31, 2012, the unvested stock options were not recognized in diluted earnings per share ("Diluted EPS") calculations as they would be antidilutive. Options for 1,716,109 shares were excluded from the calculation of diluted shares because they would have had an antidilutive effect. For the year ended December 31, 2011, outstanding options for 3,577,104 shares with an average price of $11.78 were included in the calculation of diluted shares. Options for 881,254 shares were excluded from the calculation because they would have had an antidilutive effect.

For the year ended December 31, 2013, 258,396 shares of restricted stock were included in the calculation of diluted shares. The calculation excluded 114,433 shares of restricted stock because they would have had an antidilutive effect. As we recognized a net loss for the year ended December 31, 2012, the unvested share-based payments were not recognized in diluted earnings per share ("Diluted EPS") calculations as they would be antidilutive. The calculation of diluted shares excluded 602,429 shares of restricted because they would have had an antidilutive effect. For the year ended December 31, 2011, 241,044 shares of restricted stock were included in the calculation of diluted shares. The calculation excluded 135,352 shares of restricted stock because they would have had an antidilutive effect.

### *Supplemental Disclosures of Cash Flow Information*

Supplemental disclosures of cash flow information (in thousands):

| | For the years ended December 31, | | |
|---|---|---|---|
| | **2013** | 2012 | 2011 |
| | | (in thousands) | |
| Cash paid during the year for interest, net of amounts capitalized | **$ 36,267** | $ 17,311 | $ 19,159 |
| Cash paid during the year for income taxes | **18,787** | 818 | 4,198 |
| Increase (decrease) in noncash property additions | **(12,730)** | (26,240) | 30,389 |

### *Stock-Based Compensation*

The Company accounts for stock-based compensation transactions using a fair value method and recognizes an amount equal to the fair value of the stock options and stock-based payment cost in either the consolidated statement of operations or capitalizes the cost into natural gas and oil properties or gathering systems included in property and equipment. Costs are capitalized when they are directly related to the acquisition, exploration and development activities of the Company's natural gas and oil properties or directly related to the construction of the Company's gathering systems.

### *Treasury Stock*

The Company maintains a non-qualified deferred compensation supplemental retirement savings plan for certain key employees whereby participants may elect to defer and contribute a portion of their compensation to a Rabbi Trust, as permitted by the plan. The Company includes the assets and liability of its supplemental retirement savings plan in its consolidated balance sheet. Shares of the Company's common stock purchased under the non-qualified deferred compensation arrangement are held in the Rabbi Trust and are presented as treasury stock and carried at cost. As of December 31, 2013, 9,924 shares were accounted for as treasury stock, compared to 64,715 shares at December 31, 2012.

***Foreign Currency Translation***

We have designated the Canadian dollar as the functional currency for our operations in Canada. The cumulative translation effects of translating the accounts from the functional currency into the U.S. dollar at current exchange rates are included as a separate component of stockholders' equity.

**New Accounting Standards Implemented in this Report**

In January 2013, the FASB issued Accounting Standards Update No. 2013-01, *Balance Sheet (Topic 210): Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities* ("Update 2013-01"), which finalizes Proposed ASU No. 2012-250 and clarifies the scope of transactions that are subject to disclosures concerning offsetting. Update 2013-01 addresses implementation issues regarding the scope of ASU No. 2011-11, *Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities*, issued in December 2011. Update 2013-01 clarifies that the scope of the disclosures under U.S. GAAP is limited to derivatives, repurchase agreements and reverse purchase agreements, and securities borrowing and securities lending transactions that are offset either in accordance with FASB ASC Section 210-20-45, *Balance Sheet—Offsetting—Other Presentation Matters*, or FASB ASC Section 815-10-45, *Derivatives and Hedging—Overall—Other Presentation Matters*, or are subject to a master netting arrangement or similar agreement. Update 2013-01 requires an entity (1) to apply the amendments for annual reporting periods beginning on or after January 1, 2013 and (2) to provide the required disclosures retrospectively for all comparative periods presented. The implementation of the disclosure requirement did not have a material impact on the Company's consolidated results of operations, financial position or cash flows.

In February 2013, the FASB issued Accounting Standards Update No. 2013-02, *Comprehensive Income (Topic 220): Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income* ("Update 2013-02"), which finalizes Proposed ASU No. 2012-240, and seeks to improve the transparency of reporting reclassifications out of accumulated other comprehensive income. Update 2013-02 replaces the presentation requirements in ASU No. 2011-05, *Comprehensive Income (Topic 220): Presentation of Comprehensive Income*, and ASU No. 2011-12, *Comprehensive Income (Topic 220): Deferral of the Effective Date for Amendments to the Presentation of Reclassifications of Items Out of Accumulated Other Comprehensive Income in Accounting Standards Update No. 2011-05*. Update 2013-02 requires an entity to report the effect of significant reclassifications out of accumulated other comprehensive income on the respective line items in net income if the amount being reclassified is required under U.S. GAAP to be reclassified in its entirety to net income. For public entities, Update 2013-02 is effective prospectively for reporting periods beginning after December 15, 2012, with early adoption permitted. The implementation of the disclosure requirement did not have a material impact on the Company's consolidated results of operations, financial position or cash flows.

**(2) ACQUISITIONS AND DIVESTITURES**

In April 2013, the Company entered into a definitive purchase agreement to acquire natural gas properties located in Pennsylvania prospective for the Marcellus Shale for approximately $93.0 million, subject to closing conditions. The Company closed the acquisition during the second quarter of 2013 and accounted for it as an asset acquisition.

In May 2012, we sold certain oil and natural gas leases, wells and gathering equipment in East Texas for approximately $164 million. The assets included in the sale represented all of the Company's interests and related assets in the Overton Field in Smith County. The net production from the sold assets was approximately 24.0 MMcfe per day as of the closing date and our net proved reserves were approximately 143.0 Bcfe at December 31, 2011.

## (3) PREPAID EXPENSES

The components of prepaid expenses included in other current assets as of December 31, 2013 and 2012 consisted of the following:

| | 2013 | 2012 |
|---|---|---|
| | (in thousands) | |
| Prepaid drilling costs | **$ 9,560** | $ 30,101 |
| Prepaid insurance | **7,619** | 9,507 |
| Prepaid taxes | **13,624** | 572 |
| Total | **$ 30,803** | $ 40,180 |

## (4) NATURAL GAS AND OIL PRODUCING ACTIVITIES (UNAUDITED)

The Company's natural gas and oil properties are located in the United States and Canada.

***Net Capitalized Costs***

The following table shows the capitalized costs of natural gas and oil properties and the related accumulated depreciation, depletion and amortization as of December 31, 2013 and 2012:

| | 2013 | 2012 |
|---|---|---|
| | (in thousands) | |
| Proved properties | **$ 12,337,372** | $ 10,259,226 |
| Unproved properties | **956,469** [(1)] | 1,023,888 [(1)] |
| Total capitalized costs | **13,293,841** | 11,283,114 |
| Less: Accumulated depreciation, depletion and amortization | **7,481,335** | 6,774,174 |
| Net capitalized costs | **$ 5,812,506** | $ 4,508,940 |

(1) Includes $72.3 and $40.4 million related to our exploration program in Canada as of December 31, 2013 and 2012, respectively.

Oil and gas properties not subject to amortization represent investments in unproved properties and major development projects in which we own an interest. These unproved property costs include unevaluated costs associated with leasehold or drilling interests and unevaluated costs associated with wells in progress. The table below sets forth the composition of net unevaluated costs excluded from amortization as of December 31, 2013.

| | 2013 | 2012 | 2011 | Prior | Total |
|---|---|---|---|---|---|
| | | | (in thousands) | | |
| Property acquisition costs | $ 147,791 | $ 81,889 | $ 221,451 | $ 109,994 | **$ 561,125** [(1)] |
| Exploration and development costs | 166,725 | 48,428 | 47,784 | 38,858 | **301,795** [(1)] |
| Capitalized interest | 7,792 | 11,067 | 38,145 | 36,545 | **93,549** [(1)] |
| | $ 322,308 | $ 141,384 | $ 307,380 | $ 185,397 | **$ 956,469** |

(1) Property acquisition costs include $35.0 million, exploration costs include $31.8 million and capitalized interest includes $5.5 million related to our exploration program in Canada.

Of the total net unevaluated costs excluded from amortization as of December 31, 2013, approximately $23.1 million is related to unevaluated seismic costs in the Fayetteville Shale, approximately $39.0 million is related to acquisition of undeveloped properties in the Company's Fayetteville Shale, approximately $195.7 million is related to acquisition of undeveloped properties in the Company's Marcellus Shale and approximately $275.8 million is related to acquisition of undeveloped properties in the Company's New Ventures, excluding our exploration program in Canada. The Company has $72.3 million of unevaluated costs related to its exploration program in Canada. Additionally, the Company has approximately $220.7 million of unevaluated costs related to costs of wells in progress. The remaining costs excluded from amortization are related to properties which are not individually significant and on which the evaluation process has not been completed. The timing and amount of property acquisition and seismic costs included in the amortization computation will depend on the location and timing of drilling wells, results of drilling, and other assessments. The Company is, therefore, unable to estimate when these costs will be included in the amortization computation.

***Costs Incurred in Natural Gas and Oil Exploration and Development***

The table below sets forth capitalized costs incurred in natural gas and oil property acquisition, exploration and development activities:

| | **2013** | 2012 | 2011 |
|---|---|---|---|
| | (in thousands, except per Mcfe amounts) | | |
| Proved property acquisition costs | **$ 572** | $ – | $ 17 |
| Unproved property acquisition costs | **168,404** (1) | 220,822 (1) | 262,886 (1) |
| Exploration costs | **192,164** (2) | 197,280 (2) | 63,419 (2) |
| Development costs | **1,662,138** | 1,492,841 | 1,633,784 |
| Capitalized costs incurred | **2,023,278** | 1,910,943 | 1,960,106 |
| Full cost pool amortization per Mcfe | **$ 1.08** | $ **1.31** | $ 1.30 |

(1) Includes $17.1 million, $3.6 million and $0.2 million, in 2013, 2012 and 2011, respectively, related to our exploration program in Canada.
(2) Includes $11.5 million, $2.5 million and $18.4 million in 2013, 2012 and 2011, respectively, related to our exploration program in Canada.

Capitalized interest is included as part of the cost of natural gas and oil properties. The Company capitalized $61.6 million, $62.1 million and $43.4 million during 2013, 2012 and 2011, respectively, based on the Company's weighted average cost of borrowings used to finance expenditures.

In addition to capitalized interest, the Company capitalized internal costs totaling $262.2 million, $236.5 million and $207.9 million during 2013, 2012 and 2011, respectively, that were directly related to the acquisition, exploration and development of the Company's natural gas and oil and oil properties  Included in these amounts are internal costs from the Company's subsidiaries involved with vertical integration of the Company's exploration and development activities and totaled $104.3 million, $81.7 million and $51.3 million during 2013, 2012 and 2011, respectively.  All internal costs are included in the Company's cost of natural gas and oil properties.

***Results of Operations from Natural Gas and Oil Producing Activities***

The table below sets forth the results of operations from natural gas and oil producing activities:

| | **2013** | 2012 | 2011 |
|---|---|---|---|
| | | (in thousands) | |
| Sales | **$ 2,404,165** | $ 1,963,172 | $ 2,098,914 |
| Production (lifting) costs | **(628,817)** | (505,271) | (469,153) |
| Depreciation, depletion and amortization | **(735,215)** | (765,192) | (666,107) |
| Impairment of natural gas and oil properties | **–** | (1,939,734) | – |
| | **1,040,133** | (1,247,025) | 963,654 |
| Provision (benefit) for income taxes | **416,042** | (496,738) | 375,435 |
| Results of operations (1) | **$ 624,091** | $ (750,287) | $ 588,219 |

(1) Results of operations exclude the mark-to-market gain or loss on commodity derivative instruments.  See Note 5 Derivatives and Risk Management.

The results of operations shown above exclude general and administrative expenses, and interest expense and are not necessarily indicative of the contribution made by our natural gas and oil operations to the Company's consolidated operating results. Income tax expense is calculated by applying the statutory tax rates to the revenues less costs, including depreciation, depletion and amortization, and after giving effect to permanent differences and tax credits.

### *Natural Gas and Oil Reserve Quantities*

The Company engaged the services of Netherland, Sewell & Associates, Inc., or NSAI, an independent petroleum engineering firm, to audit the reserves estimated by the Company's reservoir engineers. In conducting its audit, the engineers and geologists of NSAI studied the Company's major properties in detail and independently developed reserve estimates. NSAI's audit consists primarily of substantive testing, which includes a detailed review of the Company's major properties and accounted for approximately 95%, 93% and 90% of the present worth of the Company's total proved reserves as of December 31, 2013, 2012 and 2011, respectively. A reserve audit is not the same as a financial audit and a reserve audit is less rigorous in nature than a reserve report prepared by an independent petroleum engineering firm containing its own estimate of reserves. Reserve estimates are inherently imprecise and the Company's reserve estimates are generally based upon extrapolation of historical production trends, analogy to similar properties and volumetric calculations. Accordingly, the Company's estimates are expected to change, and such changes could be material and occur in the near term as future information becomes available. For more information over reserves, refer to the table titled "Changes in Proved Undeveloped Reserves (Bcfe)" in "Business – Exploration and Production" in Item 1 of this Form 10-K.

The following table summarizes the changes in the Company's proved natural gas and oil reserves for 2013, 2012 and 2011 all of which were located in the United States:

| | **2013** | | 2012 | | 2011 | |
|---|---|---|---|---|---|---|
| | **Natural Gas (MMcf)** | **Oil (MBbls)** | Natural Gas (MMcf) | Oil (MBbls) | Natural Gas (MMcf) | Oil (MBbls) |
| Proved reserves, beginning of year | **4,016,798** | **244** | 5,887,207 | 996 | 4,929,980 | 1,219 |
| Revisions of previous estimates | **325,374** | **88** | (2,087,985) | (44) | 34,505 | (125) |
| Extensions, discoveries and other additions | **3,283,495** | **229** | 918,594 | 154 | 1,459,428 | 2 |
| Production | **(655,704)** | **(188)** | (564,484) | (83) | (499,433) | (97) |
| Acquisition of reserves in place | **4,114** | **–** | – | – | 13 | – |
| Disposition of reserves in place | **–** | **–** | (136,534) | (779) | (37,286) | (3) |
| Proved reserves, end of year | **6,974,077** | **373** | 4,016,798 | 244 | 5,887,207 | 996 |
| | | | | | | |
| Proved developed reserves: | | | | | | |
| Beginning of year | **3,195,662** | **243** | 3,254,018 | 983 | 2,687,238 | 1,173 |
| End of year | **4,237,495** | **372** | 3,195,662 | 243 | 3,254,018 | 983 |
| | | | | | | |
| Proved undeveloped reserves: | | | | | | |
| Beginning of year | **821,136** | **1** | 2,633,189 | 13 | 2,242,742 | 46 |
| End of year | **2,736,582** | **1** | 821,136 | 1 | 2,633,189 | 13 |

The significant revision of previous estimates in 2012 was primarily due to price revision, as a result of lower average natural gas prices in 2012. The Company has no reserves from synthetic gas, synthetic oil or nonrenewable natural resources intended to be upgraded into synthetic gas or oil.

### *Standardized Measure of Discounted Future Net Cash Flows*

The following standardized measures of discounted future net cash flows relating to proved natural gas and oil reserves as of December 31, 2013, 2012 and 2011 are calculated after income taxes and discounted using a 10% annual discount rate and do not purport to present the fair market value the Company's proved gas and oil reserves:

| | **2013** | 2012 | 2011 |
|---|---|---|---|
| | | (in thousands) | |
| Future cash inflows | **$ 22,624,562** | $ 9,570,652 | $ 22,012,205 |
| Future production costs | **(8,895,956)** | (4,737,297) | (8,080,207) |
| Future development costs | **(3,626,496)** | (711,050) | (3,425,185) |
| Future income tax expense | **(3,223,271)** | (745,251) | (3,366,175) |
| Future net cash flows | **6,878,839** | 3,377,054 | 7,140,638 |
| 10% annual discount for estimated timing of cash flows | **(3,142,795)** | (1,326,389) | (3,689,838) |
| Standardized measure of discounted future net cash flows | **$ 3,736,044** | $ 2,050,665 | $ 3,450,800 |

Under the standardized measure, future cash inflows were estimated by applying an average price from the first day of each month from the previous 12 months, adjusted for known contractual changes, to the estimated future production of year-end proved reserves. Prices used for the standardized measure above were $3.67 per MMBtu for natural gas and $93.42 per barrel for oil in 2013, $2.76 per MMBtu for natural gas and $91.21 per barrel for oil in 2012, and $4.12 per MMBtu for natural gas and $92.71 per barrel for oil in 2011. Future cash inflows were reduced by estimated future production and development costs based on year-end costs to determine pre-tax cash inflows. Future income taxes were computed by applying the year-end statutory rate to the excess of pre-tax cash inflows over the Company's tax basis in the associated proved gas and oil properties after giving effect to permanent differences and tax credits.

Following is an analysis of changes in the standardized measure during 2013, 2012 and 2011:

| | **2013** | 2012 | 2011 |
|---|---|---|---|
| | | (in thousands) | |
| Standardized measure, beginning of year | **$ 2,050,665** | $ 3,450,800 | $ 3,013,750 |
| Sales and transfers of natural gas and oil produced, net of production costs | **(1,774,043)** | (1,443,606) | (1,632,156) |
| Net changes in prices and production costs | **1,852,772** | (2,604,591) | (381,131) |
| Extensions, discoveries, and other additions, net of future production and development costs | **1,454,634** | 549,601 | 1,163,992 |
| Acquisition of reserves in place | **4,914** | – | 30 |
| Sales of reserves in place | – | (157,108) | (11,761) |
| Revisions of previous quantity estimates | **348,996** | (1,109,409) | 34,221 |
| Accretion of discount | **232,385** | 480,315 | 426,245 |
| Net change in income taxes | **(1,119,798)** | 1,079,158 | (103,643) |
| Changes in estimated future development costs | **(196,394)** | 2,475,470 | 70,492 |
| Previously estimated development costs incurred during the year | **222,982** | 61,949 | 564,894 |
| Changes in production rates (timing) and other | **658,931** | (731,914) | 305,867 |
| Standardized measure, end of year | **$ 3,736,044** | $ 2,050,665 | $ 3,450,800 |

## (5) DERIVATIVES AND RISK MANAGEMENT

The Company is exposed to volatility in market prices and basis differentials for natural gas and oil which impacts the predictability of its cash flows related to the sale of natural gas and oil. These risks are managed by the Company's use of certain derivative financial instruments. As of December 31, 2013 and 2012, the Company's derivative financial instruments consisted of price swaps, basis swaps, fixed price call options, and interest rate swaps. A description of the Company's derivative financial instruments is provided below:

| | |
|---|---|
| *Fixed price swaps* | The Company receives a fixed price for the contract and pays a floating market price to the counterparty. |
| *Floating price swaps* | The Company receives a floating market price from the counterparty and pays a fixed price. |
| *Basis swaps* | Arrangements that guarantee a price differential for natural gas from a specified delivery point. The Company receives a payment from the counterparty if the price differential is greater than the stated terms of the contract and pays the counterparty if the price differential is less than the stated terms of the contract. |
| *Fixed price call options* | The Company sells fixed price call options in exchange for a premium. At the time of settlement, if the market price exceeds the fixed price of the call option, the Company pays the counterparty such excess on sold fixed price call options. If the market price settles below the fixed price of the call option, no payment is due from either party. |
| *Interest rate swaps* | Interest rate swaps are used to fix or float interest rates on existing or anticipated indebtedness. The purpose of these instruments is to manage the Company's existing or anticipated exposure to unfavorable interest rate changes. |

GAAP requires that all derivatives be recognized in the balance sheet as either an asset or liability and be measured at fair value. Under GAAP, certain criteria must be satisfied in order for derivative financial instruments to be classified and accounted for as either a cash flow or a fair value hedge. Accounting for qualifying hedges requires a derivative's gains and losses to be recorded either in earnings or as a component of other comprehensive income. Gains and losses on derivatives that are not elected for hedge accounting treatment or that do not meet hedge accounting requirements are recorded in earnings as a component of gain (loss) on derivatives. Within the gain (loss) on derivatives component of the statement of operations are gains (losses) on derivatives, net of settlement and gains (losses) on derivatives, settled. The Company calculates gains (losses) on derivatives, settled, as the summation of gains and losses on positions that have settled within the period.

The Company utilizes counterparties for its derivative instruments that it believes are credit-worthy at the time the transactions are entered into and the Company closely monitors the credit ratings of these counterparties. Additionally, the Company performs both quantitative and qualitative assessments of these counterparties based on their credit ratings and credit default swap rates where applicable. However, the events in the financial markets in recent years demonstrate there can be no assurance that a counterparty will be able to meet its obligations to the Company.

The balance sheet classification of the derivative financial instruments are summarized below as of December 31, 2013 and 2012:

| | Derivative Assets | | | |
|---|---|---|---|---|
| | **December 31, 2013** | | December 31, 2012 | |
| | **Balance Sheet Classification** | **Fair Value** | Balance Sheet Classification | Fair Value |
| | | **(in thousands)** | | |
| Derivatives designated as hedging instruments: | | | | |
| Fixed price swaps | **Derivative asset** | **$ 20,631** | Derivative asset | $ 279,443 |
| Fixed price swaps | **Other long-term assets** | **–** | Other long-term assets | 8,550 |
| Total derivatives designated as hedging instruments | | **$ 20,631** | | $ 287,993 |
| Derivatives not designated as hedging instruments: | | | | |
| Basis swaps | **Derivative asset** | **$ 12,858** | Derivative asset | $ 3,250 |
| Fixed price swaps | **Derivative asset** | **37,382** | Derivative asset | – |
| Basis swaps | **Other long-term assets** | **107** | Other long-term assets | 901 |
| Interest rate swaps | **Other long-term assets** | **7,525** | Other long-term assets | – |
| Total derivatives not designated as hedging instruments | | **$ 57,872** | | $ 4,151 |
| Total derivative assets | | **$ 78,503** | | $ 292,144 |

| | Derivative Liabilities | | | |
|---|---|---|---|---|
| | **December 31, 2013** | | December 31, 2012 | |
| | **Balance Sheet Classification** | **Fair Value** | Balance Sheet Classification | Fair Value |
| | | **(in thousands)** | | |
| Derivatives designated as hedging instruments: | | | | |
| Fixed price swaps | **Other current liabilities** | **$ 3,884** | Other current liabilities | $ – |
| Total derivatives designated as hedging instruments | | **$ 3,884** | | $ – |
| Derivatives not designated as hedging instruments: | | | | |
| Basis swaps | **Other current liabilities** | **$ 1,501** | Other current liabilities | $ 138 |
| Fixed price swaps | **Other current liabilities** | **185** | Other current liabilities | – |
| Fixed price call options | **Other long-term liabilities** | **30,388** | Other long-term liabilities | 4,128 |
| Interest rate swaps | **Other current liabilities** | **1,520** | Other current liabilities | – |
| Interest rate swaps | **Other long-term liabilities** | **3,012** | Other long-term liabilities | – |
| Total derivatives not designated as hedging instruments | | **$ 36,606** | | $ 4,266 |
| Total derivative liabilities | | **$ 40,490** | | $ 4,266 |

As of December 31, 2013, the Company had derivatives designated as cash flow hedges and derivatives not designated as hedges on the following volumes of natural gas production (in Bcf):

| Year | Fixed price swaps | Fixed price swaps not designated for hedge accounting | Total |
|---|---|---|---|
| 2014 | 200.7 | 181.6 | 382.3 |

***Cash Flow Hedges***

The reporting of gains and losses on cash flow derivative hedging instruments depends on whether the gains or losses are effective at offsetting changes in the cash flows of the hedged item. The effective portion of the gains and losses on the derivative hedging instruments are recorded in other comprehensive income until recognized in earnings during the period that the hedged transaction takes place. The ineffective portion of the gains and losses from the derivative hedging instrument recognized in earnings immediately.

As of December 31, 2013, the Company recorded a gain in accumulated other comprehensive income related to its hedging activities of $9.3 million net of a deferred income tax liability of $6.2 million. The amount recorded in accumulated other comprehensive income will be relieved over time and recognized in the statement of operations as the physical transactions being hedged occur. Assuming the market prices of natural gas futures as of December 31, 2013 remain unchanged, the Company would expect to transfer an aggregate after-tax net gain of approximately $9.3 million from accumulated other comprehensive income to earnings during the next 12 months. Gains or losses from derivative instruments designated as cash flow hedges are reflected as adjustments to natural gas sales in the consolidated statements of operations. Natural gas sales included a realized gain from settled contracts of $309.2 million for the year ended December 31, 2013 compared to a realized gain of $631.5 million for the year ended December 31, 2012. Volatility in net income, comprehensive income and accumulated other comprehensive income may occur in the future as a result of the Company's derivative activities.

The following tables summarize the before tax effect of all cash flow hedges on the consolidated financial statements for the years ended December 31, 2013 and 2012.

| Derivative Instrument | Gain Recognized in Other Comprehensive Income (Effective Portion) For the years ended December 31, 2013 | 2012 |
|---|---|---|
| | (in thousands) | |
| Fixed price swaps | $ **37,931** | $ 178,660 |
| Costless-collars | $ – | $ 39,247 |

| Derivative Instrument | Classification of Gain Reclassified from Accumulated Other Comprehensive Income into Earnings (Effective Portion) | Gain Reclassified from Accumulated Other Comprehensive Income into Earnings (Effective Portion) For the years ended December 31, 2013 | 2012 |
|---|---|---|---|
| | | (in thousands) | |
| Fixed price swaps | Gas Sales | $ **309,177** | $ 413,410 |
| Costless-collars | Gas Sales | $ – | $ 218,119 |

| Derivative Instrument | Classification of Gain (Loss) Recognized in Earnings (Ineffective Portion) | Gain (Loss) Recognized in Earnings (Ineffective Portion) For the years ended December 31, 2013 | 2012 |
|---|---|---|---|
| | | (in thousands) | |
| Fixed price swaps | Gas Sales | **$ (1,652)** | $ 2,450 |
| Costless-collars | Gas Sales | **$** – | $ (24) |

***Fair Value Hedges and Other Derivative Contracts***

For fair value hedges, the gain or loss on the derivative instrument as well as the offsetting gain or loss on the hedged item are recognized in earnings immediately.

Although the Company's basis swaps meet the objective of managing commodity price exposure, these trades are typically not entered into concurrent with the Company's derivative instruments that qualify as cash flow hedges and therefore do not generally qualify for hedge accounting. Basis swap derivative instruments that are not designated for hedge accounting are recorded on the balance sheet at their fair values under derivative assets, other assets, other current liabilities, and other long-term liabilities, as applicable and all gains and losses related to these contracts are recognized immediately in the consolidated statements of operations as a component of gain (loss) on derivatives.

As of December 31, 2013, the Company had basis swaps on natural gas production that were not designated for hedge accounting of 21.3 Bcf for 2014 and 0.9 Bcf for 2015.

As of December 31, 2013, the Company had fixed price call options on 199.8 Bcf of 2015 natural gas production not designated for hedge accounting treatment and fixed price swaps of 181.6 Bcf of 2014 natural gas production not designated for hedge accounting.

The Company is a party to interest rate swaps with counterparty banks. The interest rate swaps were entered into in order to mitigate the Company's exposure to volatility in interest rates related to construction of its new corporate office complex. The interest rate swaps build to a notional amount of $170.0 million and expire on June 20, 2020. The Company did not designate the interest rate swaps for hedge accounting. Changes in the fair value of the interest rate swaps are included in gain (loss) on derivatives in the consolidated statements of operations. The Company had no interest rate swaps in 2012.

The following tables summarizes the before tax effect of fair value hedges, fixed price call options and basis swaps that were not designated for hedge accounting, and fixed price swaps and interest rate swaps not designated for hedge accounting on the uncondensed consolidated statements of operations for the years ended December 31, 2013 and 2012.

| Derivative Instrument | Consolidated Statement of Operations Classification of Gain (Loss) on Derivatives, Net of Settlement | Gain (Loss) on Derivatives, net of settlement Recognized in Earnings For the years ended December 31, 2013 | 2012 |
|---|---|---|---|
| | | (in thousands) | |
| Basis swaps | Gain (Loss) on Derivatives | **$ 7,450** | $ 766 |
| Fixed price call options | Gain (Loss) on Derivatives | **(26,259)** | (4,128) |
| Fixed price swaps | Gain (Loss) on Derivatives | **37,197** | – |
| Fair value swaps | Gain (Loss) on Derivatives | **–** | 1,208 |
| Interest rate swaps | Gain (Loss) on Derivatives | **2,992** | – |

| Derivative Instrument | Consolidated Statement of Operations Classification of Gain (Loss) on Derivatives, Settled (1) | Gain (Loss) on Derivatives, Settled (1) Recognized in Earnings For the years ended December 31, 2013 | 2012 |
|---|---|---|---|
| | | (in thousands) | |
| Basis swaps | Gain (Loss) on Derivatives | **$ 4,772** | $ 2,162 |
| Fair value swaps | Gain (Loss) on Derivatives | **–** | (14,958) |
| Interest rate swaps | Gain (Loss) on Derivatives | **(11)** | – |

(1) The Company calculates gain (loss) on derivatives, settled, as the summation of gains and losses on positions that have settled within the period.

## (6) RECLASSIFICATIONS FROM ACCUMULATED OTHER COMPREHENSIVE INCOME

The following tables detail the components of accumulated other comprehensive income, amounts reclassified from accumulated other comprehensive income into earnings and the related tax effects for the year ended December 31, 2013:

| | For the year ended December 31, 2013 | | | |
|---|---|---|---|---|
| | Gains and Losses on Cash Flow Hedges | Pension and Other Postretirement | Foreign Currency | Total |
| | (in thousands) [1] | | | |
| Beginning balance, December 31, 2012 | $ 172,166 | $ (22,311) | $ (51) | $ 149,804 |
| Other comprehensive income (loss) before reclassifications | 21,619 | – | (4,003) | 17,616 |
| Amounts reclassified [2] | (184,515) | 12,753 | – | (171,762) |
| Net current-period other comprehensive income (loss) | (162,896) | 12,753 | (4,003) | (154,146) |
| Ending balance, December 31, 2013 | $ 9,270 | $ (9,558) | $ (4,054) | $ (4,342) |

(1) All amounts are net of tax.
(2) See separate table below for details about these reclassifications.

| Details about Accumulated Other Comprehensive Income | Consolidated Statement of Operations Classification | (in thousands) |
|---|---|---|
| Gains (losses) on cash flow hedges | | |
| Settlements | Gas sales | $ 309,177 |
| Ineffectiveness | Gas sales | (1,652) |
| | Income before income taxes | 307,525 |
| | Provision for income taxes | 123,010 |
| | Net income | $ 184,515 |
| Pension and other postretirement | | |
| Amortization of prior service cost included in net periodic pension cost [1] | General and administrative expenses | $ (21,009) |
| | Loss before income taxes | (21,009) |
| | Benefit for income taxes | (8,256) |
| | Net loss | $ (12,753) |
| Total reclassifications for the period | Net income | $ 171,762 |

(1) Included in the computation of net periodic pension cost (see Note 12 for additional details).

## (7) FAIR VALUE MEASUREMENTS

The carrying amounts and estimated fair values of the Company's financial instruments as of December 31, 2013 and 2012 were as follows:

| | December 31, 2013 | | December 31, 2012 | |
|---|---|---|---|---|
| | Carrying Amount | Fair Value | Carrying Amount | Fair Value |
| | (in thousands) | | | |
| Cash and cash equivalents | $ 22,938 | $ 22,938 | $ 53,583 | $ 53,583 |
| Restricted cash | $ – | $ – | $ 8,542 | $ 8,542 |
| Credit facility | $ 282,900 | $ 282,900 | $ – | $ – |
| Senior notes | $ 1,668,396 | $ 1,795,935 | $ 1,669,473 | $ 1,917,005 |
| Derivative instruments, net | $ 38,013 | $ 38,013 | $ 287,878 | $ 287,878 |

The carrying values of cash and cash equivalents, accounts receivable, accounts payable, other current assets and current liabilities on the consolidated balance sheets approximate fair value because of their short-term nature. For debt and derivative instruments, the following methods and assumptions were used to estimate fair value:

*Debt:* The fair values of the Company's senior notes were based on the market for the Company's publicly-traded debt as determined based on yield of the Company's 7.5% Senior Notes due 2018, which was 2.6% as of December 31, 2013 and 2.6% at December 31, 2012, and its 4.10% Senior Notes due 2022, which was 4.2% as of December 31, 2013. The carrying values of the borrowings under the Company's unsecured Credit Facility approximate fair value because the interest rate is variable and reflective of market rates. The Company considers the fair value of its debt to be a Level 2 measurement on the fair value hierarchy.

*Derivative Instruments:* The fair value of all derivative instruments is the amount at which the instrument could be exchanged currently between willing parties. The amounts are based on quoted market prices, best estimates obtained from counterparties and an option pricing model, when necessary, for price option contracts.

GAAP establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. As presented in the tables below, this hierarchy consists of three broad levels:

*Level 1 valuations -* Consist of unadjusted quoted prices in active markets for identical assets and liabilities and have the highest priority.

*Level 2 valuations -* Consist of quoted market information for the calculation of fair market value.

*Level 3 valuations -* Consist of internal estimates and have the lowest priority.

The Company has classified its derivatives into these levels depending upon the data utilized to determine their fair values. The Company's Level 2 fair value measurements include fixed-price and floating-price swaps and are estimated using third-party discounted cash flow calculations using the NYMEX futures index. The Company's Level 3 fair value measurements include costless-collars, basis swaps and fixed price call options. The Company's costless-collars and fixed price call options are valued using the Black-Scholes model, an industry standard option valuation model, and takes into account inputs such as contract terms, including maturity, and market parameters, including assumptions of the NYMEX futures index, interest rates, volatility and credit worthiness. The Company's basis swaps are estimated using third party discounted cash flow calculations based upon forward commodity price curves.

Inputs to the Black-Scholes model, including the volatility input, which is the significant unobservable input for Level 3 fair value measurements, are obtained from a third-party pricing source, with independent verification of most significant inputs on a monthly basis. An increase (decrease) in volatility would result in an increase (decrease) in fair value measurement, respectively.

Assets and liabilities measured at fair value on a recurring basis are summarized below (in thousands):

| | December 31, 2013 | | | |
|---|---|---|---|---|
| | Fair Value Measurements Using: | | | |
| | Quoted Prices in Active Markets (Level 1) | Significant Other Observable Inputs (Level 2) | Significant Unobservable Inputs (Level 3) | Assets (Liabilities) at Fair Value |
| Derivative assets | **$ –** | **$ 65,538** | **$ 12,965** | **$ 78,503** |
| Derivative liabilities | **–** | **(8,601)** | **(31,889)** | **(40,490)** |
| Total | **$ –** | **$ 56,937** | **$ (18,924)** | **$ 38,013** |

| | December 31, 2012 | | | |
|---|---|---|---|---|
| | Fair Value Measurements Using: | | | |
| | Quoted Prices in Active Markets (Level 1) | Significant Other Observable Inputs (Level 2) | Significant Unobservable Inputs (Level 3) | Assets (Liabilities) at Fair Value |
| Derivative assets | $ – | $ 287,993 | $ 4,151 | $ 292,144 |
| Derivative liabilities | – | – | (4,266) | (4,266) |
| Total | $ – | $ 287,993 | $ (115) | $ 287,878 |

The table below presents reconciliations for the change in net fair value of derivative assets and liabilities measured at fair value on a recurring basis using significant unobservable inputs (Level 3) for the years ended December 31, 2013 and 2012. The fair values of Level 3 derivative instruments are estimated using proprietary valuation models that utilize both market, observable and unobservable parameters. Level 3 instruments presented in the table consist of net derivatives valued using pricing models incorporating assumptions that, in the Company's judgment, reflect reasonable assumptions a marketplace participant would have used as of December 31, 2013 and at December 31, 2012.

Total net gains and losses for Level 3 derivatives for the years ended December 31, 2013 and 2012 are provided below:

| | For the years ended December 31, | |
|---|---|---|
| | **2013** | 2012 |
| | (in thousands) | |
| Balance at beginning of period | **$ (115)** | $ 182,119 |
| Total gains or losses (realized/unrealized): | | |
| Included in earnings | **(14,037)** | 216,857 |
| Included in other comprehensive income | **–** | (178,847) |
| Purchases, issuances, and settlements: | | |
| Purchases | **–** | – |
| Issuances | **–** | – |
| Settlements | **(4,772)** | (220,244) |
| Transfers into/out of Level 3 | **–** | – |
| Balance at end of period | **$ (18,924)** | $ (115) |
| Change in unrealized gains included in earnings relating to derivatives still held as of December 31 | **$ (18,809)** | $ (3,362) |

## (8) DEBT

The components of debt as of December 31, 2013 and 2012 consisted of the following:

| | **2013** | 2012 |
|---|---|---|
| | (in thousands) | |
| Short-term debt: | | |
| 7.15% Senior Notes due 2018 | **$ 1,200** | $ 1,200 |
| Total short-term debt [1] | **1,200** | 1,200 |
| | | |
| Long-term debt: | | |
| Variable rate (1.64% and 2.20% at December 31, 2013 and December 31, 2012, respectively) Credit Facility, expires December 2018 | **282,900** | – |
| 7.35% Senior Notes due 2017 | **15,000** | 15,000 |
| 7.125% Senior Notes due 2017 | **25,000** | 25,000 |
| 7.15% Senior Notes due 2018 | **28,200** | 29,400 |
| 7.5% Senior Notes due 2018 | **600,000** | 600,000 |
| 4.10% Senior Notes due 2022 | **1,000,000** | 1,000,000 |
| Unamortized discount | **(1,004)** | (1,127) |
| Total long-term debt | **1,950,096** | 1,668,273 |
| | | |
| Total debt | **$ 1,951,296** | $ 1,669,473 |

[1] Short-term debt is included in Other current liabilities in the Balance Sheet.

The following is a summary of scheduled long-term debt maturities by year as of December 31, 2013 (in thousands):

| | |
|---|---|
| 2015 | 1,200 |
| 2016 | 1,200 |
| 2017 | 41,200 |
| 2018 | 907,500 |
| Thereafter | 1,000,000 |
| | $ 1,951,100 |

*Credit Facility*

On December 16, 2013, the Company entered into a Credit Agreement ("Credit Facility"), that exchanged our previous revolving credit facility. Under the Credit Facility, we have a borrowing capacity of $2.0 billion. The Credit Facility has a maturity date of December 2018 and options for two one-year extensions with participating lender approval. The amount available under the Credit Facility may be increased by $500.0 million upon the Company's agreement with its participating lenders. The interest rate on the Credit Facility is calculated based upon our credit rating and is currently 150 basis points over the current London Interbank Offered Rate, or LIBOR. The borrowing rate on our previous revolving credit facility was 200 basis points over LIBOR as of December 31, 2012 and throughout 2013 until it was exchanged. The Credit Facility is unsecured and is not guaranteed by any subsidiaries of the Company. Contemporaneously with the execution of the Credit Agreement, on December 16, 2013, the Company obtained subsidiary guarantee releases under the 7.15%, 7.5%, 7.35%, 7.125% and 4.10% Senior Notes and our former credit facility. The Credit Facility contains covenants which impose certain restrictions on the Company, including a financial covenant whereby the Company may not issue total debt in excess of 60% of its total adjusted book capital. This financial covenant with respect to capitalization percentages excludes the noncontrolling interest in equity, the effects of non-cash entries that result from any full cost ceiling impairments (beginning in the year ended December 31, 2011), certain hedging activities and our pension and other postretirement liabilities. As of December 31, 2013, the Company was in compliance with the covenants of its Credit Facility and other debt agreements. Although the Company believes all of the lenders under the Credit Facility have the ability to provide funds, it cannot predict whether each will be able to meet its obligation under the facility.

## (9) COMMITMENTS AND CONTINGENCIES

### *Operating Commitments and Contingencies*

The Company has commitments to third parties for demand transportation charges. As of December 31, 2013, future payments under non-cancelable firm transportation charges are approximately $362.8 million in 2014, $399.2 million in 2015, $413.2 million in 2016, $375.7 million in 2017, $363.3 million in 2018 and $1,594.7 million thereafter.

The Company has 11 leases for pressure pumping equipment for its E&P operations under leases that expire between December 1, 2017 and January 1, 2018. The Company's current aggregate annual payment under the leases is approximately $7.5 million. The lease payments for the pressure pumping equipment, as well as other operating expenses for the Company's drilling operations, are capitalized to natural gas and oil properties and are partially offset by billings to third-party working interest owners for their share of fracture stage charges.

The Company leases compressors, aircraft, vehicles, office space and equipment under non-cancelable operating leases expiring through 2027. As of December 31, 2013, future minimum payments under these non-cancelable leases accounted for as operating leases are approximately $65.2 million in 2014, $55.9 million in 2015, $44.6 million in 2016, $27.8 million in 2017, $10.8 million in 2018 and $24.9 million thereafter. The Company also has commitments for compression services related to its Midstream Services and E&P segments. As of December 31, 2013, future minimum payments under these non-cancelable agreements are approximately $38.6 million in 2014, $24.5 million in 2015, $17.2 million in 2016, $9.2 million in 2017, $3.7 million in 2018 and $0.7 million thereafter.

In response to the Company's well performance, SES and SEPCO entered into new and amended natural gas transportation and gathering arrangements with third party pipelines during the second quarter of 2013 in support of the Company's production in the Marcellus Shale. As of December 31, 2013, the Company's obligations for demand and similar charges under the firm transportation agreements and gathering agreements totaled approximately $3.5 billion and the Company has guarantee obligations of up to $100.0 million of that amount.

In 2013, we started construction on a corporate office complex located in Spring, Texas on 26 acres of commercial land that we purchased in 2012. The Company financed the construction of this complex through a construction agreement and lease arrangement. We are currently obligated for the construction costs incurred, which approximated $38 million at December 31, 2013. Upon completion of construction, a lease term of approximately five years will commence.

In the first quarter of 2010, the Company was awarded exclusive licenses by the Province of New Brunswick in Canada to conduct an exploration program covering approximately 2.5 million acres in the province. The licenses require the Company to make certain capital investments in New Brunswick of approximately $47.0 million Canadian dollars in the aggregate over the license periods. In order to obtain the licenses, the Company provided promissory notes payable on demand to the Minister of Finance of the Province of New Brunswick with an aggregate principal amount of $44.5 million Canadian dollars. The promissory notes secure the Company's capital expenditure obligations under the licenses and are returnable to the Company to the extent the Company performs such obligations. If the Company fails to fully perform, the Minister of Finance may retain a portion of the applicable promissory notes in an amount equal to any deficiency. The Company commenced its Canada exploration program in 2010 and, as of December 31, 2013 has invested $39.2 million Canadian dollars, or $36.9 million USD, in New Brunswick towards the Company's commitment. In December 2012, the Company received two one-year extensions to our exploration licenses which expire on March 2014 and March 2015, respectively. No liability has been recognized in connection with the promissory notes due to the Company's investments in New Brunswick as of December 31, 2013 and its future investment plans.

### *Environmental Risk*

The Company is subject to laws and regulations relating to the protection of the environment. Environmental and cleanup related costs of a non-capital nature are accrued when it is both probable that a liability has been incurred and when the amount can be reasonably estimated. Management believes any future remediation or other compliance related costs will not have a material effect on the financial position or results of operations of the Company.

### *Litigation*

Tovah Energy

In February 2009, SEPCO was added as a defendant in a case then styled Tovah Energy, LLC and Toby Berry-Helfand v. David Michael Grimes, et, al., pending in the 273rd District Court in Shelby County, Texas. By the time of trial in December 2010, Ms. Berry-Helfand (the only remaining plaintiff) alleged that, in 2005, she provided SEPCO with proprietary data regarding two prospects in the James Lime formation pursuant to a confidentiality agreement and that SEPCO refused to return the proprietary data to the plaintiff, subsequently acquired leases based upon such proprietary data and profited therefrom. Among other things, she alleged various statutory and common law claims, including, but not limited to, claims of misappropriation of trade secrets, violation of the Texas Theft Liability Act, breach of fiduciary duty and confidential relationships, various fraud based claims and breach of contract, including a claim of breach of a purported right of first refusal on all interests acquired by SEPCO between February 2005 and February 2006. She also sought disgorgement of SEPCO's profits. A former associate of the plaintiff intervened in the matter claiming to have helped develop the prospect years earlier.

The jury found in favor of the plaintiff and the intervenor with respect to all of the statutory and common law claims and awarded $11.4 million in compensatory damages but no special, punitive or other damages. Separately, the jury determined that SEPCO's profits for purposes of disgorgement, if ordered as a remedy, were $381.5 million. (Disgorgement of profits is an equitable remedy determined by the judge, and it is within the judge's discretion to award none, some or all of unlawfully obtained profits.) In August 2011, a judgment was entered pursuant to which the plaintiff and the intervenor were entitled to recover approximately $11.4 million in actual damages and approximately $23.9 million in disgorgement as well as prejudgment interest and attorneys' fees, which currently are estimated to be up to $8.9 million, and all costs of court of the plaintiff and intervenor.

Both sides appealed and in July 2013, the Tyler Court of Appeals ordered that (1) the judgment awarding the plaintiff and the intervenor $23.9 million as disgorgement of illicit gains be reversed and judgment rendered that they take nothing, (2) the award of $11.4 million for actual damages, insofar as it is based on the jury's findings of breach of fiduciary duty, fraud, breach of contract, and theft of trade secret is reversed and judgment rendered that the plaintiff and the intervenor take nothing under those theories of recovery, (3) the award of $11.4 million to the plaintiff and the intervenor as damages for misappropriation of trade secret is affirmed, (4) the case be remanded to the trial court for a determination and award of attorney's fees for SEPCO as the prevailing party under the Texas Theft Liability Act, and (5) in all other respects, the judgment is affirmed. All parties petitioned for rehearing. The Tyler Court of Appeals denied rehearing in November 2013.

SEPCO filed a petition for review in the Supreme Court of Texas in February 2014. The plaintiff and the intervenor have until March 2014 to file petitions for review. Based on the Company's understanding and judgment of the facts and merits of this case, including appellate matters, and after considering the advice of counsel, the Company has determined that, although reasonably possible, a materially adverse final outcome to this action is not probable. As such, the Company has not accrued any amounts with respect to this action. If the plaintiff and the intervenor were to prevail ultimately in the appellate process, the Company currently estimates, based on the judgments to date, that SEPCO's potential liability would be up to $45.5 million, including interest and attorney's fees. If the Supreme Court declines to hear the case or affirms all aspects of the court of appeals' judgment, then SEPCO would owe the $11.4 million in damages, plus interest and attorneys fees, offset by any award of attorneys' fees for its prevailing on the theft count. The Company's assessment may change in the future due to occurrence of certain events, such as the result of the petition or petitions for review at the Supreme Court of Texas, and such a re-assessment could lead to the determination that the potential liability is probable and could be material to the Company's results of operations, financial position or cash flows.

Bureau of Land Management

In March 2010, the Company's subsidiary SEECO was served with a subpoena from a federal grand jury in Little Rock, Arkansas. Based on the documents requested under the subpoena and subsequent discussions with representatives of the Bureau of Land Management and the U.S. Attorney, the Company believed the grand jury was investigating matters involving approximately 27 horizontal wells operated by SEECO in Arkansas, including whether appropriate leases or permits were obtained therefrom and whether royalties and other production attributable to federal lands were properly accounted for and paid. In January 2014, the U.S. Attorney's office informed SEECO's outside counsel that no criminal charges will be brought. Two wells were drilled, in part, through federal lands without having obtained leases at the time of drilling, and SEECO has paid full royalties as if those leases were in place from first production of the wells. The Government has made a formal demand for additional damages for trespass; however, because these actions were not deliberate and SEECO voluntarily reported this to the Bureau of Land Management at the time the error was discovered, the Company does not believe additional damages should be assessable or that such additional damages, if any, would be material.

Other

The Company is subject to various litigation, claims and proceedings that have arisen in the ordinary course of business, such as for alleged breaches of contract, miscalculation of royalties and pollution, contamination or nuisance. Management believes that such litigation, claims and proceedings, individually or in aggregate and after taking into account insurance, are not likely to have a material adverse impact on our financial position, results of operations or cash flows. Many of these matters are in early stages, so the allegations and the damage theories have not been fully developed, and all subject to inherent uncertainties; therefore, management's view may change in the future. If an unfavorable final outcome were to occur, there exists the possibility of a material impact on the Company's financial position, results of operations or cash flows for the period in which the effect becomes reasonably estimable. The Company accrues for such items when a liability is both probable and the amount can be reasonably estimated.

***Indemnifications***

The Company provides certain indemnifications in relation to dispositions of assets. These indemnifications typically relate to disputes, litigation or tax matters existing at the date of disposition. No liability has been recognized in connection with these indemnifications.

### (10) INCOME TAXES

The provision (benefit) for income taxes included the following components:

| | **2013** | 2012 | 2011 |
|---|---|---|---|
| | | (in thousands) | |
| Current: | | | |
| Federal | **$ (12,151)** | $ 15,500 | $ 3,378 |
| State | **1,080** | 3,189 | 820 |
| | **(11,071)** | 18,689 | 4,198 |
| Deferred: | | | |
| Federal | **409,359** | (388,209) | 345,922 |
| State | **87,823** | (71,582) | 60,941 |
| Foreign | **763** | (2,037) | 2,160 |
| | **497,945** | (461,828) | 409,023 |
| Provision (benefit) for income taxes | **$ 486,874** | $ (443,139) | $ 413,221 |

The provision for income taxes was an effective rate of 40.9% in 2013, 38.5% in 2012 and 39.3% 2011. The following reconciles the provision for income taxes included in the consolidated statements of operations with the provision which would result from application of the statutory federal tax rate to pre-tax financial income:

| | 2013 | 2012 | 2011 |
|---|---|---|---|
| | | (in thousands) | |
| Expected provision (benefit) at federal statutory rate | **$ 416,632** | $ (402,571) | $ 367,854 |
| Increase (decrease) resulting from: | | | |
| State income taxes, net of federal income tax effect | **53,130** | (44,454) | 40,145 |
| Nondeductible expenses | **3,404** | 2,100 | 1,244 |
| Other | **13,708** | 1,786 | 3,978 |
| Provision (benefit) for income taxes | **$ 486,874** | $ (443,139) | $ 413,221 |

The components of the Company's net deferred tax liability as of December 31, 2013 and 2012 were as follows:

| | 2013 | 2012 |
|---|---|---|
| | (in thousands) | |
| Deferred tax liabilities: | | |
| Differences between book and tax basis of property | **$ 2,114,685** | $ 1,441,149 |
| Cash flow hedges | **13,171** | 112,625 |
| Other | **10,715** | 4,460 |
| | **2,138,571** | 1,558,234 |
| Deferred tax assets: | | |
| Accrued compensation | **15,718** | 16,387 |
| Alternative minimum tax credit carryforward | **76,864** | 89,016 |
| Stored natural gas | **9,272** | 7,812 |
| Accrued pension costs | **1,821** | 7,686 |
| Asset retirement obligations | **53,419** | 39,249 |
| Net operating loss carryforward | **411,994** | 217,276 |
| Differences between book and tax basis of property - state | **11,045** | 16,872 |
| Other | **7,405** | 12,354 |
| | **587,538** | 406,652 |
| Net deferred tax liability | **$ 1,551,033** | $ 1,151,582 |

The net deferred tax liability as of December 31, 2013 was comprised of net long-term deferred income tax liabilities of $1,526.7 million in addition to a net current deferred income tax liability of $24.3 million. The net deferred tax liability at December 31, 2012 was comprised of net long-term deferred income tax liabilities of $1,045.5 million, in addition to a net current deferred income tax liability of $106.1 million. In 2013, the Company paid $3.3 million in state income taxes and paid $15.5 million in federal income taxes. In 2012, the Company paid $0.8 million in state income taxes and did not pay any alternative minimum taxes. The Company's net operating loss carryforward as of December 31, 2013 was $1,174.7 million and $878.0 million for federal and state reporting purposes, respectively, the majority of which will expire between 2028 and 2032. In 2013 the Company recorded a $2.9 million valuation allowance against our deferred tax asset for various state net operating losses. The Company also had an alternative minimum tax credit carryforward of $76.9 million and a statutory depletion carryforward of $12.9 million as of December 31, 2013.

Our effective tax rate increased in 2013 as compared with 2012. This was primarily due to a redetermination of the deferred state tax liability to reflect updated state apportionment factors in certain higher-rate states and the recording of a valuation allowance against a portion of our deferred tax asset for state net operating losses.

Deferred tax assets relating to tax benefits of employee stock option grants have been reduced to reflect exercises in 2012. Some exercises resulted in tax deductions in excess of previously recorded benefits based on the option value at the time of the grant (“windfalls”). Although these additional tax benefits or “windfalls” are reflected in net operating loss carryforwards, pursuant to GAAP, the additional tax benefit associated with the windfall is not recognized until the deduction reduces taxes payable. Accordingly, since the tax benefit does not reduce our current taxes payable in 2013 due to net operating loss carryforwards, these “windfall” tax benefits are not reflected in our net operating losses in deferred tax assets for 2013. Windfalls included in net operating loss carryforwards but not reflected in deferred tax assets for 2013 were $131.3 million.

As of December 31, 2013, the Company has no unrecognized tax benefits.  The income tax years 2010 to 2013 remain open to examination by the major taxing jurisdictions to which the Company is subject.

The Company has an income tax net operating loss carryforward related to its Canadian operations of $22.3 million, and has expiration dates of 2030 through 2033. The Company assesses the available positive and negative evidence to estimate if sufficient future taxable income will be generated to utilize the existing deferred tax asset associated with the Canadian net operating loss. Based on this assessment, the Company did not record a valuation allowance as of December 31, 2013.

## (11) ASSET RETIREMENT OBLIGATIONS

The following table summarizes the Company's 2013 and 2012 activity related to asset retirement obligations:

| | 2013 | | 2012 | |
|---|---|---|---|---|
| | (in thousands) | | | |
| Asset retirement obligation at January 1 | **$** | **100,637** | $ | 37,693 |
| Accretion of discount | | **5,643** | | 2,394 |
| Obligations incurred | | **22,241** | | 23,327 |
| Obligations settled/removed | | **(2,341)** | | (8,804) |
| Revisions of estimates | | **7,366** | | 46,027 |
| Asset retirement obligation at December 31 | **$** | **133,546** | $ | 100,637 |
| | | | | |
| Current liability | | **5,549** | | 4,091 |
| Long-term liability | | **127,997** | | 96,546 |
| Asset retirement obligation at December 31 | **$** | **133,546** | $ | 100,637 |

In 2012, the Company recorded a correction to increase the asset retirement obligation by approximately $39 million, the effect of which was immaterial to the Company's financial statements in all affected periods.

## (12) RETIREMENT AND EMPLOYEE BENEFIT PLANS

### *401(k) Defined Contribution Plan*

The Company has a 401(k) defined contribution plan covering eligible employees. The Company expensed $2.5 million, $2.2 million and $1.9 million of contribution expense in 2013, 2012 and 2011, respectively. Additionally, the Company capitalized $2.9 million, $2.8 million and $3.8 million of contributions in 2013, 2012 and 2011, respectively, directly related to the acquisition, exploration and development activities of the Company's natural gas and oil properties or directly related to the construction of the Company's gathering systems.

### *Defined Benefit Pension and Other Postretirement Plans*

Prior to January 1, 1998, the Company maintained a traditional defined benefit plan with benefits payable based upon average final compensation and years of service. Effective January 1, 1998, the Company amended its pension plan to become a "cash balance" plan on a prospective basis for its non-bargaining employees. A cash balance plan provides benefits based upon a fixed percentage of an employee's annual compensation. The Company's funding policy is to contribute amounts which are actuarially determined to provide the plans with sufficient assets to meet future benefit payment requirements and which are tax deductible.

The postretirement benefit plan provides contributory health care and life insurance benefits. Employees become eligible for these benefits if they meet age and service requirements. Generally, the benefits paid are a stated percentage of medical expenses reduced by deductibles and other coverages.

Substantially all employees are covered by the Company's defined benefit pension and postretirement benefit plans. The Company accounts for its defined benefit pension and other postretirement plans by recognizing the funded status of each defined pension benefit plan and other postretirement benefit plan on the Company's balance sheet. In the event a plan is overfunded, the Company recognizes an asset. Conversely, if a plan is underfunded, the Company recognizes a liability.

The following provides a reconciliation of the changes in the plans' benefit obligations, fair value of assets, and funded status as of December 31, 2013 and 2012:

| | Pension Benefits | | Other Postretirement Benefits | |
|---|---|---|---|---|
| | **2013** | 2012 | **2013** | 2012 |
| | (in thousands) | | | |
| Change in benefit obligations: | | | | |
| Benefit obligation at January 1 | **$ 105,432** | $ 81,738 | **$ 11,464** | $ 6,793 |
| Service cost | **13,789** | 10,942 | **2,296** | 1,832 |
| Interest cost | **4,104** | 4,050 | **441** | 398 |
| Participant contributions | **–** | – | **24** | 21 |
| Actuarial loss | **(11,107)** | 14,981 | **(1,706)** | 2,525 |
| Benefits paid | **(8,492)** | (6,951) | **(139)** | (105) |
| Plan amendments | **–** | 672 | **–** | – |
| Settlements | **(520)** | – | **–** | – |
| Benefit obligation at December 31 | **$ 103,206** | **$** 105,432 | **$ 12,380** | **$** 11,464 |

| | Pension Benefits | | Other Postretirement Benefits | |
|---|---|---|---|---|
| | **2013** | 2012 | **2013** | 2012 |
| | (in thousands) | | | |
| Change in plan assets: | | | | |
| Fair value of plan assets at January 1 | **$ 83,347** | $ 68,023 | **$ –** | $ – |
| Actual return on plan assets | **12,471** | 11,191 | **–** | – |
| Employer contributions | **12,520** | 11,084 | **115** | 84 |
| Participant contributions | **–** | – | **24** | 21 |
| Benefits paid | **(8,492)** | (6,951) | **(139)** | (105) |
| Settlements | **(507)** | – | **–** | – |
| Fair value of plan assets at December 31 | **$ 99,339** | $ 83,347 | **$ –** | $ – |
| Funded status of plans at December 31 | **$ (3,867)** | $ (22,085) | **$ (12,380)** | $ (11,464) |

The Company uses a December 31 measurement date for all of its plans and had liabilities recorded for the underfunded status for each period as presented above.

The change in accumulated other comprehensive income related to the pension plans was a gain of $19.2 million ($11.6 million after tax) for the year ended December 31, 2013 and a loss of $8.4 million ($5.0 million after tax) for the year ended December 31, 2012. The change in accumulated other comprehensive income related to the other postretirement benefit plan was a gain of $1.8 million ($1.1 million after tax) for the year ended December 31, 2013 and was a loss of $2.4 million ($1.4 million after tax) for the year ended December 31, 2012. Included in accumulated other comprehensive income as of December 31, 2013 and 2012 was a $15.9 million loss ($9.6 million net of tax) and a $36.9 million loss ($22.3 million net of tax), respectively, related to the Company's pension and other postretirement benefit plans. For the year ended December 31, 2013, amortization of prior period service cost included in net periodic pension cost of $21.0 million was reclassified from accumulated other comprehensive income to general and administrative expenses.

The amounts in accumulated other comprehensive income that are expected to be recognized as components of net periodic benefit cost during 2014 are $0.1 million for prior service costs and $0.2 million net loss.

The pension plans' projected benefit obligation, accumulated benefit obligation and fair value of plan assets as of December 31, 2013 and 2012 are as follows:

| | **2013** | 2012 |
|---|---|---|
| | (in thousands) | |
| Projected benefit obligation | **$ 103,206** | $ 105,432 |
| Accumulated benefit obligation | **$ 100,208** | $ 100,379 |
| Fair value of plan assets | **$ 99,339** | $ 83,347 |

Pension and other postretirement benefit costs include the following components for 2013, 2012 and 2011:

| | Pension Benefits | | | Other Postretirement Benefits | | |
|---|---|---|---|---|---|---|
| | **2013** | 2012 | 2011 | **2013** | 2012 | 2011 |
| | (in thousands) | | | | | |
| Service cost | **$ 13,789** | $ 10,942 | $ 9,323 | **$ 2,296** | $ 1,832 | $ 1,354 |
| Interest cost | **4,104** | 4,050 | 3,671 | **441** | 398 | 252 |
| Expected return on plan assets | **(6,136)** | (5,426) | (4,398) | **–** | – | – |
| Amortization of transition obligation | **–** | – | – | **–** | 64 | 64 |
| Amortization of prior service cost | **103** | 286 | 344 | **14** | 14 | 14 |
| Amortization of net loss | **1,541** | 1,220 | 856 | **120** | 93 | 11 |
| Net periodic benefit cost | **13,401** | 11,072 | 9,796 | **2,871** | 2,401 | 1,695 |
| Settlements and curtailments | **70** | – | – | **–** | – | – |
| Total benefit cost | **$ 13,471** | $ 11,072 | $ 9,796 | **$ 2,871** | $ 2,401 | $ 1,695 |

Amounts recognized in other comprehensive income for the year ended December 31, 2013 were as follows:

| | Pension Benefits | Other Postretirement Benefits |
|---|---|---|
| | (in thousands) | |
| Net actuarial gain arising during the year | $ 17,454 | $ 1,706 |
| Amortization of prior service cost | 104 | 14 |
| Amortization of net loss | 1,541 | 120 |
| Settlements | 70 | – |
| Tax effect | (7,535) | (721) |
| | $ 11,634 | $ 1,119 |

The assumptions used in the measurement of the Company's benefit obligations as of December 31, 2013 and 2012 are as follows:

| | Pension Benefits | | Other Postretirement Benefits | |
|---|---|---|---|---|
| | **2013** | 2012 | **2013** | 2012 |
| Discount rate | **5.00 %** | 4.00 % | **5.00 %** | 4.00 % |
| Rate of compensation increase | **4.50 %** | 4.50 % | **n/a** | n/a |

The assumptions used in the measurement of the Company's net periodic benefit cost for 2013, 2012 and 2011 are as follows:

| | Pension Benefits | | | Other Postretirement Benefits | | |
|---|---|---|---|---|---|---|
| | **2013** | 2012 | 2011 | **2013** | 2012 | 2011 |
| Discount rate | **4.00 %** | 5.00 % | 5.50 % | **4.00 %** | 5.00 % | 5.50 % |
| Expected return on plan assets | **7.00 %** | 7.50 % | 7.50 % | **n/a** | n/a | n/a |
| Rate of compensation increase | **4.50 %** | 4.50 % | 4.50 % | **n/a** | n/a | n/a |

The expected return on plan assets for the various benefit plans is based upon a review of the historical returns experienced, combined with the future expected returns based upon the asset allocation strategy employed. The plans seek to achieve an adequate return to fund the obligations in a manner consistent with the federal standards of the Employee Retirement Income Security Act and with a prudent level of diversification.

For measurement purposes, the following trend rates were assumed for 2013 and 2012:

| | **2013** | 2012 |
|---|---|---|
| Health care cost trend assumed for next year | **8 %** | 8 % |
| Rate to which the cost trend is assumed to decline | **5 %** | 5 % |
| Year that the rate reaches the ultimate trend rate | **2032** | 2031 |

Assumed health care cost trend rates have a significant effect on the amounts for the health care plans. A one percentage point change in assumed health care cost trend rates would have the following effects:

| | 1% Increase | 1% Decrease |
|---|---|---|
| | (in thousands) | |
| Effect on the total service and interest cost components | $ 457 | $ (373) |
| Effect on postretirement benefit obligations | $ 1,693 | $ (1,413) |

***Pension Payments and Asset Management***

In 2013, the Company contributed $12.5 million to its pension plans and $0.1 million to its other postretirement benefit plan. The Company expects to contribute $12.0 million to its pension plans and $0.4 million to its other postretirement benefit plan in 2014. No plan assets are expected to be returned to the Company during the next twelve months.

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

| | Pension Benefits | Other Postretirement Benefits |
|---|---|---|
| | (in thousands) | |
| 2014 | $ 6,384 | $ 404 |
| 2015 | $ 6,280 | $ 542 |
| 2016 | $ 8,075 | $ 730 |
| 2017 | $ 8,553 | $ 801 |
| 2018 | $ 9,517 | $ 994 |
| Years 2019-2023 | $ 58,894 | $ 7,545 |

The Company's overall investment strategy is to provide an adequate pool of assets to support both the long-term growth of plan assets and to ensure adequate liquidity exists for the near-term benefit payment of obligations to participants, retirees and beneficiaries. The Benefits Administration Committee of the Company administers the Company's pension plan assets. The Benefits Administration Committee believes long-term investment performance is a function of asset-class mix and restricts the composition of pension plan assets to a combination of cash and cash equivalents, domestic equity markets, international equity markets or investment grade fixed income assets.

The table below presents the allocations targeted by the Benefits Administration Committee and the actual weighted-average asset allocation of the Company's pension plan as of December 31, 2013, by asset category. The asset allocation targets are subject to change and the Benefits Administration Committee allows for its actual allocations to deviate from target as a result of current and anticipated market conditions. Plan assets are periodically balanced whenever the allocation to any asset class falls outside of the specified range.

| | Pension Plan Asset Allocations | |
|---|---|---|
| Asset category: | Target | Actual |
| U.S. Equity(1) | 35 % | 36 % |
| Non-U.S. Developed Equity(2) | 30 % | 31 % |
| Emerging Markets Equity(3) | 5 % | 6 % |
| Opportunistic(4) | – % | – % |
| Fixed income(5) | 29 % | 26 % |
| Cash(6) | 1 % | 1 % |
| Total | 100 % | 100 % |

(1) Asset category above includes the following equity securities in the table below: U.S large cap growth equity, U.S. large cap value equity, U.S. large cap core equity, and U.S. small cap equity.
(2) Asset category above includes Non-U.S. equity securities in the table below.
(3) Asset category above includes Emerging markets equity securities below.
(4) Asset category above includes none of the securities in the table below.
(5) Asset category above includes Fixed income pension plan assets in the table below.
(6) Asset category above includes Cash and cash equivalents pension plan assets in the table below.

Utilizing GAAP's fair value hierarchy, the Company's fair value measurement of pension plan assets as of December 31, 2013 are as follows:

| Asset category: | Total | Quoted Prices in Active Markets for Identical Assets (Level 1) | Significant Observable Inputs (Level 2) | Significant Unobservable Inputs (Level 3) |
|---|---|---|---|---|
| | | (in thousands) | | |
| Equity securities: | | | | |
| U.S. large cap growth equity[1] | $ 7,660 | $ 7,660 | $ – | $ – |
| U.S. large cap value equity[2] | 8,174 | 8,174 | – | – |
| U.S. large cap core equity[3] | 16,438 | – | 16,438 | – |
| U.S. small cap equity[4] | 3,245 | 3,245 | – | – |
| Non-U.S. equity[5] | 30,628 | 30,628 | – | – |
| Emerging markets equity[6] | 6,374 | – | 6,374 | – |
| Fixed income [7] | 25,523 | – | 25,523 | – |
| Cash and cash equivalents | 1,296 | 1,296 | – | – |
| Total | $ 99,338 | $ 51,003 | $ 48,335 | $ – |

(1) Mutual fund that seeks to invest in a diversified portfolio of stocks with price appreciation growth opportunities.
(2) Mutual fund that seeks to invest in a diversified portfolio of stocks that will increase in value over the long-term as well as provide current income.
(3) An institutional fund that seeks to replicate the performance of the S&P 500 Index before fees.
(4) Mutual fund that seeks to invest in a diversified portfolio of stocks with small market capitalizations.
(5) Mutual funds that invest primarily in equity securities of companies domiciled outside of the United States, primarily in developed markets.
(6) An institutional fund that invests primarily in the equity securities of companies domiciled in emerging markets.
(7) Institutional funds that seek an investment return that approximates, as closely as practicable, before expenses, the performance of the Barclays U.S. Intermediate Credit Bond Index over the long term and the Barclays Long U.S. Corporate Bond Index over the long-term.

Utilizing GAAP's fair value hierarchy, the Company's fair value measurement of pension plan assets at December 31, 2012 are as follows:

| Asset category: | Total | Quoted Prices in Active Markets for Identical Assets (Level 1) | Significant Observable Inputs (Level 2) | Significant Unobservable Inputs (Level 3) |
|---|---|---|---|---|
| | | (in thousands) | | |
| Equity securities: | | | | |
| U.S. large cap growth equity[1] | $ 4,588 | $ 4,588 | $ – | $ – |
| U.S. large cap value equity[2] | 5,257 | 5,257 | – | – |
| U.S. large cap core equity[3] | 11,564 | – | 11,564 | – |
| U.S. small cap equity[4] | 2,792 | 2,792 | – | – |
| Non-U.S. equity[5] | 21,891 | 21,891 | – | – |
| Emerging markets equity[6] | 4,454 | – | 4,454 | – |
| Fixed income [7] | 31,021 | – | 31,021 | – |
| Cash and cash equivalents | 1,780 | 1,780 | – | – |
| Total | $ 83,347 | $ 36,308 | $ 47,039 | $ – |

(1) Mutual fund that seeks to invest in a diversified portfolio of stocks with price appreciation growth opportunities.
(2) Mutual fund that seeks to invest in a diversified portfolio of stocks that will increase in value over the long-term as well as provide current income.
(3) An institutional fund that seeks to replicate the performance of the S&P 500 Index before fees.
(4) Mutual fund that seeks to invest in a diversified portfolio of stocks with small market capitalizations.
(5) Mutual funds that invest primarily in equity securities of companies domiciled outside of the United States, primarily in developed markets.
(6) An institutional fund that invests primarily in the equity securities of companies domiciled in emerging markets.
(7) An institutional fund that seeks to replicate the performance of the Barclays Capital Long-Term Corporate Bond Index before fees through a sampling process.

The Company's pension plan assets that are classified as Level 1 are due to the pension plan's investments comprising either cash or investments in open-ended mutual funds which produce a daily net asset value that is validated with a sufficient level of observable activity to support classification of the fair value measurement as Level 1. The Company's Level 2 pension plan assets represent investments in institutional funds. These equity securities can be redeemed on demand but are not actively traded. The fair values of these Level 2 securities are based upon the net asset values provided by the investment managers. No concentration of risk arising within or across categories of plan assets exists due to any significant investments in a single entity, industry, country or investment fund.

**(13) STOCK-BASED COMPENSATION**

The Southwestern Energy Company 2013 Incentive Plan (2013 Plan) was adopted in February 2013 and approved by stockholders in May 2013. The 2013 Plan provides for the compensation of officers, key employees and eligible non-employee directors of the Company and its subsidiaries. The 2013 Plan replaced the Southwestern Energy Company 2004 Stock Incentive Plan, the Southwestern Energy Company 2000 Stock Incentive Plan (2000 Plan) and the Southwestern Energy Company 2002 Employee Stock Incentive Plan (2002 Plan) but did not affect prior awards under those plans which remained valid and some of which are still outstanding. The awards under the prior plans have been adjusted for stock splits as permitted under such plans.

The 2013 Plan provides for grants of options, stock appreciation rights, and shares of restricted stock and restricted stock units to employees, officers and directors that in the aggregate do not exceed 20,500,000 shares. The types of incentives that may be awarded are comprehensive and are intended to enable the Company's board of directors to structure the most appropriate incentives and to address changes in income tax laws which may be enacted over the term of the 2013 Plan.

As initially adopted, the 2004 Plan, the 2000 Plan and the 2002 Plan provided for grants of options, stock appreciation rights, shares of phantom stock and shares of restricted stock that in the aggregate did not exceed 16,800,000, 1,125,000 and 300,000 shares, respectively, to employees who are not officers or directors of the Company under provisions of Section 16 of the Securities Exchange Act of 1934, as amended.

The Company may utilize treasury shares, if available, or authorized but unissued shares when a stock option is exercised or when restricted stock is granted.

The Company measures the cost of employee services received in exchange for an award of equity instruments based on the grant date fair value of the award. All options are issued at fair market value at the date of grant and expire seven years from the date of grant for awards under both the 2013 Plan and the 2004 Plan and ten years from the date of grant for awards under all other plans. Generally, stock options granted to employees and directors vest ratably over three years from the grant date. The Company issues shares of restricted stock to employees and directors which generally vest over four years. The Company recognizes stock-based compensation expense on a straight-line basis over the requisite service period of the individual grants with the exception of awards granted to participants who have reached retirement age or will reach retirement age during the vesting period. Restricted stock and stock options granted to participants on or after December 6, 2013 immediately vest upon death, disability or retirement (subject to a minimum of three years of service).

***Stock Options***

The Company recorded the following compensation costs related to stock options for the years ended December 31, 2013, 2012 and 2011:

| | **2013** | 2012 | 2011 |
|---|---|---|---|
| | | (in thousands) | |
| Stock-based compensation cost related to stock options – general and administrative expense | **$ 5,494** | $ 5,427 | $ 4,959 |
| Stock-based compensation cost related to stock options – capitalized | **$ 4,812** | $ 4,468 | $ 3,365 |

The Company also recorded a deferred tax benefit of $4.0 million related to stock options in 2013, compared to deferred tax benefits of $2.2 million in 2012 and $1.7 million in 2011. A total of $16.2 million of unrecognized compensation cost related to the Company's unvested stock option and restricted stock grants. This cost is expected to be recognized over a weighted-average period of 2.1 years.

The fair value of stock options is estimated on the date of the grant using a Black-Scholes valuation model that uses the weighted average assumptions noted in the following table. Expected volatility is based on historical volatility of the Company's common stock and other factors. The Company uses historical data on exercise of stock options, post vesting forfeitures and other factors to estimate the expected term of the stock-based payments granted. The risk free interest rate is based on the U.S. Treasury yield curve in effect at the time of grant.

| Assumptions | **2013** | 2012 | 2011 |
|---|---|---|---|
| Risk-free interest rate | **1.5%** | 0.6% | 0.9% |
| Expected dividend yield | – | – | – |
| Expected volatility | **38.6%** | 58.2% | 58.1% |
| Expected term | **5 years** | 5 years | 5 years |

The following tables summarize stock option activity for the years 2013, 2012 and 2011 and provide information for options outstanding at December 31 of each year:

| | **2013** | | 2012 | | 2011 | |
|---|---|---|---|---|---|---|
| | **Number of Shares** | **Weighted Average Exercise Price** | Number of Shares | Weighted Average Exercise Price | Number of Shares | Weighted Average Exercise Price |
| Options outstanding at January 1 | **3,649,520** | **$ 29.84** | 4,741,732 | $ 21.24 | 4,769,122 | $ 16.13 |
| Granted | **571,166** | **38.95** | 613,120 | 34.34 | 853,478 | 36.64 |
| Exercised | **(833,132)** | **12.12** | (1,607,784) | 5.71 | (850,659) | 7.54 |
| Forfeited or expired | **(74,861)** | **37.31** | (97,548) | 37.76 | (30,209) | 35.46 |
| Options outstanding at December 31 | **3,312,693** | **$ 35.70** | 3,649,520 | $ 29.84 | 4,741,732 | $ 21.24 |

| | Options Outstanding | | | | Options Exercisable | | | |
|---|---|---|---|---|---|---|---|---|
| Range of Exercise Prices | **Options Outstanding December 31, 2013** | **Weighted Average Exercise Price** | Weighted Average Remaining Contractual Life (Years) | Aggregate Intrinsic Value (thousands) | Options Exercisable at December 31, 2013 | Weighted Average Exercise Price | Weighted Average Remaining Contractual Life (Years) | Aggregate Intrinsic Value (thousands) |
| $20.34-$29.69 | **273,134** | **27.31** | 1.2 | | 265,025 | 27.29 | 1.1 | |
| $30.23-$35.91 | **1,087,218** | **33.09** | 4.3 | | 677,387 | 32.32 | 3.4 | |
| $36.22-$39.91 | **1,587,066** | **37.56** | 5.4 | | 803,412 | 36.74 | 4.4 | |
| $40.15-$51.47 | **365,275** | **41.64** | 3.0 | | 358,004 | 41.62 | 2.9 | |
| | **3,312,693** | **$ 35.70** | 4.4 | $ 12,882 | 2,103,828 | $ 34.96 | 2.9 | $ 10,022 |

The weighted-average grant-date fair value of options granted during the years 2013, 2012 and 2011 was $13.39, $16.91 and $18.17, respectively. The total intrinsic value of options exercised during 2013, 2012 and 2011 was $21.7 million, $44.1 million and $27.0 million, respectively.

***Restricted Stock***

The Company recorded the following compensation costs related to restricted stock grants for the years ended December 31, 2013, 2012 and 2011:

| | | **2013** | | 2012 (in thousands) | | 2011 |
|---|---|---|---|---|---|---|
| Stock-based compensation cost related to restricted stock grants – general and administrative expense | $ | **7,432** | $ | 6,368 | $ | 5,591 |
| Stock-based compensation cost related to restricted stock grants – capitalized | $ | **7,469** | $ | 5,994 | $ | 5,162 |

The Company also recorded a deferred tax liability of $14.8 million related to restricted stock for the year ended December 31, 2013, compared to deferred tax liabilities of $1.4 million for 2012 and $2.1 million for 2011. As of December 31, 2013, there was $62.5 million of total unrecognized compensation cost related to unvested shares of restricted stock that is expected to be recognized over a weighted-average period of 3.4 years.

The following table summarizes the restricted stock activity for the years 2013, 2012 and 2011 and provides information for restricted stock outstanding at December 31 of each year:

| | **2013** | | | 2012 | | | 2011 | | |
|---|---|---|---|---|---|---|---|---|---|
| | **Number of Shares** | | **Weighted Average Grant Date Fair Value** | Number of Shares | | Weighted Average Grant Date Fair Value | Number of Shares | | Weighted Average Grant Date Fair Value |
| Unvested shares at January 1 | **1,117,515** | **$** | **35.64** | 1,019,737 | $ | 36.71 | 834,058 | $ | 36.24 |
| Granted | **1,108,852** | | **38.92** | 537,244 | | 34.39 | 532,754 | | 36.41 |
| Vested | **(381,676)** | | **36.29** | (344,164) | | 36.50 | (294,358) | | 34.90 |
| Forfeited | **(73,769)** | | **35.81** | (95,302) | | 36.97 | (52,717) | | 36.45 |
| Unvested shares at December 31 | **1,770,922** | **$** | **37.55** | 1,117,515 | $ | 35.64 | 1,019,737 | $ | 36.71 |

The fair values of the grants were $43.2 million for 2013, $18.5 million for 2012 and $19.4 million for 2011. The total fair value of shares vested were $13.9 million for 2013, $12.6 million for 2012 and $10.9 million for 2011.

***Liability-Classified Performance Units***

Certain employees were provided performance units vesting equally over three years. The payout of these units is based on certain metrics, such as total shareholder return and reserve replacement efficiency, compared to a predetermined group of peer companies and Company goal. At the end of each performance period, the value of the vested performance units, if any, is paid in cash. The Company paid $3.3 million related to the vested performance units in 2013, $19.1 million in 2012, and $15.8 million in 2011. As of December 31, 2013 and 2012, the Company's liability under the performance unit agreements was $45.3 million and $41.3 million, respectively.

## (14) SEGMENT INFORMATION

The Company's reportable business segments have been identified based on the differences in products or services provided. Revenues for the E&P segment are derived from the production and sale of natural gas and oil. The Midstream Services segment generates revenue through the marketing of both Company and third-party produced natural gas volumes and through gathering fees associated with the transportation of natural gas to market.

Summarized financial information for the Company's reportable segments is shown in the following table. The accounting policies of the segments are the same as those described in Note 1. Management evaluates the performance of its segments based on operating income, defined as operating revenues less operating costs and expenses. Income before income taxes, for the purpose of reconciling the operating income amount shown below to consolidated income before income taxes, is the sum of operating income, interest expense and other income (loss), net. The "Other" column includes items not related to the Company's reportable segments including real estate and corporate items.

| | Exploration and Production | Midstream Services | Other | Total |
|---|---|---|---|---|
| | (in thousands) | | | |
| **2013** | | | | |
| Revenues from external customers | **$ 2,398,214** | **$ 972,832** | **$ 99** | **$ 3,371,145** |
| Intersegment revenues | **5,951** | **2,373,851** | **241** | **2,380,043** |
| Operating income (loss) | **878,701** | **325,435** | **(513)** | **1,203,623** |
| Other income (loss), net | **2,741** | **(1)** | **(533)** | **2,207** |
| Gain (loss) on derivatives | **25,670** | **480** | **(9)** | **26,141** |
| Depreciation, depletion and amortization expense | **735,215** | **50,940** | **457** | **786,612** |
| Interest expense(2) | **30,244** | **10,619** | **731** | **41,594** |
| Provision (benefit) for income taxes(2) | **368,320** | **119,223** | **(669)** | **486,874** |
| Assets | **6,356,799** (3) | **1,427,294** | **263,633** | **8,047,726** |
| Capital investments(4) | **2,052,148** | **157,635** | **25,014** | **2,234,797** |
| **2012** | | | | |
| Revenues from external customers | $ 1,964,624 | $ 765,255 | $ 114 | $ 2,729,993 |
| Intersegment revenues | (1,452) | 1,598,225 | 2,751 | 1,599,524 |
| Operating income (loss) (1) | (1,396,261) | 294,302 | 1,333 | (1,100,626) |
| Other income (loss), net | (1,156) | 132 | 2,054 | 1,030 |
| Loss on derivatives | (14,950) | – | – | (14,950) |
| Depreciation, depletion and amortization expense | 765,368 | 44,395 | 1,190 | 810,953 |
| Impairment of natural gas and oil properties | 1,939,734 | – | – | 1,939,734 |
| Interest expense(2) | 20,315 | 14,341 | 1,001 | 35,657 |
| Provision for income taxes(2) | (548,556) | 104,522 | 895 | (443,139) |
| Assets | 5,193,733 (3) | 1,273,228 | 270,566 | 6,737,527 |
| Capital investments(4) | 1,860,681 | 164,978 | 54,860 | 2,080,519 |
| **2011** | | | | |
| Revenues from external customers | $ 2,087,189 | $ 864,096 | $ 47 | $ 2,951,332 |
| Intersegment revenues | 11,725 | 1,995,423 | 3,221 | 2,010,369 |
| Operating income | 823,564 | 247,952 | 1,711 | 1,073,227 |
| Other income (loss), net | 328 | (91) | 27 | 264 |
| Gain on derivatives | 1,574 | – | – | 1,574 |
| Depreciation, depletion and amortization expense | 666,125 | 37,261 | 1,125 | 704,511 |
| Interest expense(2) | 9,026 | 15,049 | – | 24,075 |
| Provision for income taxes(2) | 322,714 | 90,221 | 286 | 413,221 |
| Assets | 6,547,117 (3) | 1,119,861 | 235,919 | 7,902,897 |
| Capital investments(4) | 1,977,493 | 160,776 | 68,905 | 2,207,174 |

(1) The operating loss for the E&P segment for the twelve months ended December 31, 2012 includes a $1,939.7 million non-cash ceiling test impairment of our natural gas and oil properties.

(2) Interest expense and the provision (benefit) for income taxes by segment are an allocation of corporate amounts as they are incurred at the corporate level.

(3) Includes office, technology, drilling rigs and other ancillary equipment not directly related to natural gas and oil property acquisition, exploration and development activities.

(4) Capital investments include a decrease of $24.9 million for 2013, a decrease of $36.9 million for 2012 and an increase of $4.3 million for 2011 related to the change in accrued expenditures between years.

Included in intersegment revenues of the Midstream Services segment are approximately $2.0 billion, $1.3 billion and $1.7 billion for 2013, 2012 and 2011, respectively, for marketing of the Company's E&P sales. Corporate assets include cash and cash equivalents, restricted cash, furniture and fixtures, prepaid debt and other costs. Corporate general and administrative costs, depreciation expense and taxes other than income are allocated to the segments. For 2013, 2012, and 2011, capital investments within the E&P segment include $35.4 million, $11.6 million, and $18.7 respectively, related to the Company's activities in Canada. As of December 31, 2013, 2012, and 2011, E&P assets include $79.2 million, $44.4 million, $28.4 million related to the Company's activities in Canada.

## (15) QUARTERLY RESULTS (UNAUDITED)

The following is a summary of the quarterly results of operations for the years ended December 31, 2013 and 2012:

| | 1st Quarter | 2nd Quarter | 3rd Quarter | 4th Quarter |
|---|---|---|---|---|
| | (in thousands, except per share amounts) | | | |
| | **2013** | | | |
| Operating revenues | **$ 733,649** | **$ 862,041** | **$ 868,366** | **$ 907,089** |
| Operating income | **251,960** | **325,317** | **309,229** | **317,117** |
| Net income | **127,515** | **245,631** | **185,867** | **144,490** |
| Earnings per share - Basic | **0.36** | **0.70** | **0.53** | **0.41** |
| Earnings per share - Diluted | **0.36** | **0.70** | **0.53** | **0.41** |
| | 2012 | | | |
| Operating revenues | $ 654,835 | $ 606,076 | $ 691,727 | $ 777,355 |
| Operating income [1] | 184,326 | (646,046) | (65,959) | (572,947) |
| Net income | 107,704 | (405,132) | (54,053) | (355,583) |
| Earnings per share - Basic | 0.31 | (1.16) | (0.16) | (1.02) |
| Earnings per share - Diluted | 0.31 | (1.16) | (0.16) | (1.02) |

[1] 2012 Operating income includes an impairment charge for the full year of $1,939.7 million.

## (16) CONDENSED CONSOLIDATING FINANCIAL INFORMATION

As of December 16, 2013, following the release of all guarantees under the 7.15%, 7.5%, 7.35%, 7.125% and 4.10% Senior Notes and our former credit facility, as described in Note 8, all of our 100%-owned subsidiaries have been released of their guarantees.

Prior to that date, the Company's obligations under registered public debt and outstanding senior notes as listed in Note 8 were fully and unconditionally guaranteed, jointly and severally, by all of our 100%-owned subsidiaries, other than minor subsidiaries, on a senior unsecured basis, and the Company, as a parent company, had no independent assets or operations. The subsidiary guarantees (i) ranked equally in right of payment with all of the existing and future senior debt of the subsidiary guarantors; (ii) ranked senior to all of the existing and future subordinated debt of the subsidiary guarantors; (iii) were effectively subordinated to any future secured obligations of the subsidiary guarantors to the extent of the value of the assets securing such obligations; and (iv) were structurally subordinated to all debt and other obligations of the subsidiaries of the guarantors. In the case of each series of notes, if no default or event of default had occurred and was continuing, these guarantees would be released (i) automatically upon any sale, exchange or transfer of all of the Company's equity interests in the guarantor; (ii) automatically upon the liquidation and dissolution of a guarantor; (iii) following delivery of notice to the trustee of the release of the guarantor of its obligations under the Company's revolving credit facility; and (iv) upon legal or covenant defeasance or other satisfaction of the obligations under the notes. In addition, there were no significant restrictions on the ability of the Company or any guarantor to obtain funds from its subsidiaries by dividend or loan, and none of the assets of the Company or a guarantor represented restricted net assets pursuant to Rule 4-08(e)(3) of Regulation S-X under the Securities Act.

The Company is providing condensed consolidating financial information for SEECO, SEPCO and SES, its subsidiaries that were guarantors of the Company's registered public debt and outstanding senior notes, and for its other subsidiaries that are not guarantors of such debt as of and for the years December 31, 2012 and 2011. The Company has not provided comparative financial statements for 2013 because all guarantees were released in 2013. The Company has not presented separate financial and narrative information for each of the former subsidiary guarantors because it believes that such financial and narrative information would not provide any additional information that would be material in evaluating the sufficiency of the guarantees. The following condensed consolidating financial information summarizes the results of operations, financial position and cash flows for the Company's former guarantor and other subsidiaries.

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS

| | Parent | Former Guarantors | Other Subsidiaries | Eliminations | Consolidated |
|---|---|---|---|---|---|
| | | | (in thousands) | | |
| Year ended December 31, 2012: | | | | | |
| Operating revenues | $ – | $ 2,556,634 | $ 476,997 | $ (303,638) | $ 2,729,993 |
| Operating costs and expenses: | | | | | |
| Gas purchases | – | 593,091 | – | (625) | 592,466 |
| Operating expenses | – | 423,147 | 121,953 | (300,365) | 244,735 |
| General and administrative expenses | – | 151,488 | 26,307 | (2,648) | 175,147 |
| Depreciation, depletion and amortization | – | 765,623 | 45,330 | – | 810,953 |
| Impairment of natural gas and oil properties | – | 1,939,734 | – | – | 1,939,734 |
| Taxes, other than income taxes | – | 56,262 | 11,321 | 1 | 67,584 |
| Total operating costs and expenses | – | 3,929,345 | 204,911 | (303,637) | 3,830,619 |
| Operating income (loss) | – | (1,372,711) | 272,086 | (1) | (1,100,626) |
| Other income (loss), net | – | (1,143) | 2,173 | – | 1,030 |
| Gain (loss) on derivatives | – | (14,950) | – | – | (14,950) |
| Equity in earnings of subsidiaries | (707,064) | – | – | 707,064 | – |
| Interest expense | – | 22,312 | 13,345 | – | 35,657 |
| Income (loss) before income taxes | (707,064) | (1,411,116) | 260,914 | 707,063 | (1,150,203) |
| Provision (benefit) for income taxes | – | (538,357) | 95,218 | – | (443,139) |
| Net income (loss) | (707,064) | (872,759) | 165,696 | 707,063 | (707,064) |
| Comprehensive income (loss) | $ (965,688) | $ (1,125,454) | $ 166,225 | $ 959,229 | $ (965,688) |
| Year ended December 31, 2011: | | | | | |
| Operating revenues | $ – | $ 2,801,811 | $ 411,998 | $ (262,477) | $ 2,951,332 |
| Operating costs and expenses: | | | | | |
| Gas purchases | – | 710,487 | – | (1,396) | 709,091 |
| Operating expenses | – | 380,154 | 118,713 | (257,923) | 240,944 |
| General and administrative expenses | – | 141,499 | 19,700 | (3,158) | 158,041 |
| Depreciation, depletion and amortization | – | 665,615 | 38,896 | – | 704,511 |
| Taxes, other than income taxes | – | 53,950 | 11,568 | – | 65,518 |
| Total operating costs and expenses | – | 1,951,705 | 188,877 | (262,477) | 1,878,105 |
| Operating income | – | 850,106 | 223,121 | – | 1,073,227 |
| Other income (loss), net | – | 306 | (42) | – | 264 |
| Gain (loss) on derivatives | – | 1,574 | – | – | 1,574 |
| Equity in earnings of subsidiaries | 637,769 | – | – | (637,769) | – |
| Interest expense | – | 11,277 | 12,798 | – | 24,075 |
| Income (loss) before income taxes | 637,769 | 840,709 | 210,281 | (637,769) | 1,050,990 |
| Provision for income taxes | – | 332,795 | 80,426 | – | 413,221 |
| Net income (loss) | 637,769 | 507,914 | 129,855 | (637,769) | 637,769 |
| Comprehensive income (loss) | $ 962,222 | $ 836,291 | $ 129,294 | $ (965,585) | $ 962,222 |

CONDENSED CONSOLIDATING BALANCE SHEET

| | Parent | Former Guarantors | Other Subsidiaries | Eliminations | Consolidated |
|---|---|---|---|---|---|
| | | | (in thousands) | | |
| December 31, 2012: | | | | | |
| **ASSETS** | | | | | |
| Cash and cash equivalents | $ 47,491 | $ 5,988 | $ 104 | $ – | $ 53,583 |
| Restricted cash | 8,542 | – | – | – | 8,542 |
| Accounts receivable | 2,677 | 353,607 | 21,354 | – | 377,638 |
| Inventories | 2 | 26,975 | 1,164 | – | 28,141 |
| Other current assets | 7,461 | 321,396 | 12,151 | – | 341,008 |
| Total current assets | 66,173 | 707,966 | 34,773 | – | 808,912 |
| Intercompany receivables | 2,259,713 | 42 | 27,077 | (2,286,832) | – |
| Property and equipment | 220,837 | 11,491,222 | 1,316,380 | – | 13,028,439 |
| Less: Accumulated depreciation, depletion and amortization | (82,178) | (6,923,106) | (186,179) | – | (7,191,463) |
| | 138,659 | 4,568,116 | 1,130,201 | – | 5,836,976 |
| Investments in subsidiaries (equity method) | 2,309,947 | – | – | (2,309,947) | – |
| Other assets | 35,136 | 42,247 | 14,256 | – | 91,639 |
| Total assets | $ 4,809,628 | $ 5,318,371 | $ 1,206,307 | $ (4,596,779) | $ 6,737,527 |
| **LIABILITIES AND EQUITY** | | | | | |
| Accounts payable | $ 140,367 | $ 375,604 | $ 41,009 | $ – | $ 556,980 |
| Other current liabilities | 3,758 | 205,623 | 1,410 | – | 210,791 |
| Total current liabilities | 144,125 | 581,227 | 42,419 | – | 767,771 |
| Intercompany payables | – | 2,108,360 | 178,472 | (2,286,832) | – |
| Long-term debt | 1,668,273 | – | – | – | 1,668,273 |
| Deferred income taxes | (116,207) | 820,279 | 345,066 | – | 1,049,138 |
| Other liabilities | 77,565 | 124,505 | 14,403 | – | 216,473 |
| Total liabilities | 1,773,756 | 3,634,371 | 580,360 | (2,286,832) | 3,701,655 |
| Commitments and contingencies | | | | | |
| Total equity | 3,035,872 | 1,684,000 | 625,947 | (2,309,947) | 3,035,872 |
| Total liabilities and equity | $ 4,809,628 | $ 5,318,371 | $ 1,206,307 | $ (4,596,779) | $ 6,737,527 |

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

| | Parent | Former Guarantors | Other Subsidiaries | Eliminations | Consolidated |
|---|---|---|---|---|---|
| | | | (in thousands) | | |
| Year ended December 31, 2012: | | | | | |
| Net cash provided by operating activities | $ (39,934) | $ 1,278,673 | $ 415,203 | $ – | $ 1,653,942 |
| Investing activities: | | | | | |
| Capital investments | (36,918) | (1,868,487) | (202,350) | – | (2,107,755) |
| Proceeds from sale of property and equipment | 26,006 | 169,149 | 5,946 | – | 201,101 |
| Transfers to restricted cash | (167,788) | – | – | – | (167,788) |
| Transfers from restricted cash | 159,245 | 1 | – | – | 159,246 |
| Other | (696) | (35,792) | 45,007 | – | 8,519 |
| Net cash used in investing activities | (20,151) | (1,735,129) | (151,397) | – | (1,906,677) |
| Financing activities: | | | | | |
| Intercompany activities | (198,023) | 462,443 | (264,420) | – | – |
| Payments on current portion of long-term debt | (1,200) | – | – | – | (1,200) |
| Payments on revolving long-term debt | (2,263,900) | – | – | – | (2,263,900) |
| Borrowings under revolving long-term debt | 1,592,400 | – | – | – | 1,592,400 |
| Proceeds from issuance of long-term debt | 998,780 | – | – | – | 998,780 |
| Other | (35,192) | 1 | – | – | (35,191) |
| Net cash provided by (used in) financing activities | 92,865 | 462,444 | (264,420) | – | 290,889 |
| Effect of exchange rate changes on cash | – | – | (198) | – | (198) |
| Increase (decrease) in cash and cash equivalents | 32,780 | 5,988 | (812) | – | 37,956 |
| Cash and cash equivalents at beginning of year | 14,711 | – | 916 | – | 15,627 |
| Cash and cash equivalents at end of period | $ 47,491 | $ 5,988 | $ 104 | $ – | $ 53,583 |

| | Parent | Former Guarantors | Other Subsidiaries | Eliminations | Consolidated |
|---|---|---|---|---|---|
| Year ended December 31, 2011: | | | | | |
| Net cash provided by operating activities | $ 14,688 | $ 1,482,853 | $ 242,276 | $ – | $ 1,739,817 |
| Investing activities: | | | | | |
| Capital investments | (66,647) | (1,916,246) | (201,581) | – | (2,184,474) |
| Proceeds from sale of property and equipment | – | 154,261 | 265 | – | 154,526 |
| Transfers to restricted cash | (85,055) | – | – | – | (85,055) |
| Transfers from restricted cash | 85,055 | – | – | – | 85,055 |
| Other | 16,263 | (43,961) | 32,856 | – | 5,158 |
| Net cash used in investing activities | (50,384) | (1,805,946) | (168,460) | – | (2,024,790) |
| Financing activities: | | | | | |
| Intercompany activities | (242,277) | 315,462 | (73,185) | – | – |
| Payments on current portion of long-term debt | (1,200) | – | – | – | (1,200) |
| Payments on revolving long-term debt | (3,445,900) | – | – | – | (3,445,900) |
| Borrowings under revolving long-term debt | 3,696,200 | – | – | – | 3,696,200 |
| Other | 35,203 | – | – | – | 35,203 |
| Net cash provided by financing activities | 42,026 | 315,462 | (73,185) | – | 284,303 |
| Effect of exchange rate changes on cash | – | – | 242 | – | 242 |
| Increase (decrease) in cash and cash equivalents | 6,330 | (7,631) | 873 | – | (428) |
| Cash and cash equivalents at beginning of year | 8,381 | 7,631 | 43 | – | 16,055 |
| Cash and cash equivalents at end of period | $ 14,711 | $ – | $ 916 | $ – | $ 15,627 |

## ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

## ITEM 9A. CONTROLS AND PROCEDURES

### Disclosure Controls and Procedures

We have performed an evaluation under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures, as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934 (the Exchange Act). Our disclosure controls and procedures are the controls and other procedures that we have designed to ensure that we record, process, accumulate and communicate information to our management, including our Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosures and submission within the time periods specified in the SEC's rules and forms. All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those determined to be effective can provide only a level of reasonable assurance with respect to financial statement preparation and presentation. Based on the evaluation, our management, including our Chief Executive Officer and Chief Financial Officer, concluded that our disclosure controls and procedures were effective as of December 31, 2013 at a reasonable assurance level. There were no changes in our internal control over financial reporting during the three months ended December 31, 2013, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting is included on page 65 of this Form 10-K.

PricewaterhouseCoopers LLP's report on Southwestern Energy's internal control over financial reporting is included in its Report of Independent Registered Public Accounting Firm on page 66 of this Form 10-K.

## ITEM 9B. OTHER INFORMATION

On February 25, 2014, the Board of Directors of the Company approved amendments to Section 2.4, Article IV and Section 7.5 of the Company's Amended and Restated Bylaws (the "Bylaws") to require director nominees to agree to be bound by future changes to Company guidelines and policies, to allow officers of the Company to be designated as senior vice presidents, and to add a forum selection clause, respectively. The Bylaws as amended and restated (the "Amended and Restated Bylaws") are filed as Exhibit 3.2 to this Annual Report on Form 10-K and incorporated herein by reference. The foregoing description of the Amended and Restated Bylaws does not purport to be complete and is qualified in its entirety by reference to the Amended and Restated Bylaws.

**PART III**

**ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE**

| Name | Officer Position | Age | Years Served as Officer |
|---|---|---|---|
| Steven L. Mueller | President and Chief Executive Officer | 60 | 5 |
| William J. Way | Executive Vice President and Chief Operating Officer | 54 | 2 |
| Mark K. Boling | President - V+ Development Solutions | 56 | 12 |
| R. Craig Owen | Senior Vice President and Chief Financial Officer | 44 | 5 |
| Jeffrey B. Sherrick | Executive Vice President – Corporate Development | 59 | 5 |
| John C. Ale | Senior Vice President, General Counsel and Secretary | 59 | * |

* Mr. Ale was appointed to his present position in November 2013.

Mr. Mueller was appointed Chief Executive Officer in May 2009 and was elected to the Board of Directors in July 2009. Mr. Mueller joined us as President and Chief Operating Officer in June 2008. He joined us from CDX Gas, LLC, where he was employed as Executive Vice President from September 2007 to May 2008. From 2001 until 2007, Mr. Mueller served first as the Senior Vice President and General Manager Onshore and later as the Executive Vice President and Chief Operating Officer of The Houston Exploration Company. A graduate of the Colorado School of Mines, Mr. Mueller has over 30 years of experience in the oil and natural gas industry and has served in multiple operational and managerial roles at Tenneco Oil Company, Fina Oil Company, American Exploration Company and Belco Oil & Gas Company.

Mr. Way joined the Company in 2011 as Executive Vice President and Chief Operating Officer of Southwestern Energy. Prior to joining the Company, he was Senior Vice President, Americas of BG Group plc with responsibility for E&P, Midstream and LNG operations in the United States, Trinidad and Tobago, Chile, Bolivia, Canada and Argentina. He is a graduate of Texas A&M University with a degree in Industrial Engineering and has an MBA from The Massachusetts Institute of Technology.

Mr. Boling was appointed to his present position in December 2012. He joined us as Senior Vice President, General Counsel and Secretary in January 2002, positions in which he served until November 2013. He became Executive Vice President, General Counsel and Secretary of the Company later in 2002. Prior to joining the company, Mr. Boling had a private law practice in Houston specializing in the natural gas and oil industry from 1993 to 2002. Previously, Mr. Boling was a partner with Fulbright and Jaworski L.L.P., where he was employed from 1982 to 1993.

Mr. Owen was appointed to his present position in October 2012. He joined the Company as Controller in July 2008 and was promoted to Senior Vice President in May 2012. Immediately prior to joining the Company, he was Controller, Operations Accounting of Anadarko Petroleum Corporation, where he had held various managerial positions since 2001. Prior to Anadarko Petroleum, Mr. Owen was a business assurance manager at PricewaterhouseCoopers LLP in Houston, Texas, serving clients in the energy, insurance, banking and investment industries, and held various financial reporting roles with ARCO Pipe Line Company and Hilcorp Energy Company. Mr. Owen holds a bachelor of business administration degree in accounting from Texas A&M University and is a Certified Public Accountant.

Mr. Sherrick was appointed to his present position in December 2013. He joined the Company in October 2008 as Senior Vice President, U.S. Exploitation of Southwestern Energy's subsidiaries SEECO, Inc. and Southwestern Energy Production Company. From 2005 to 2007, Mr. Sherrick served as the Senior Vice President, Corporate Development of The Houston Exploration Company. In 2004, he served as the Senior Vice President, Production and Nonregulated Services of El Paso Production Company. From 1999 through 2002, he served as the Chairman, CEO and President of Enron Global Exploration and Production Inc., and prior to that he served in multiple operational and managerial roles at Enron Oil & Gas Company, and Tenneco Oil Company. Mr. Sherrick is a graduate of Marietta College with a Bachelor of Science degree in Petroleum Engineering.

Mr. Ale joined the Company in November 2013 as Senior Vice President, General Counsel and Secretary. Prior to Southwestern Energy, Mr. Ale was Vice President and General Counsel of Occidental Petroleum Corporation. Previously, he was a partner with Skadden, Arps, Slate, Meagher & Flom LLP and Vinson & Elkins LLP. Mr. Ale served as a law clerk to Chief Justice Warren E. Burger of the U.S. Supreme Court and to Judge Edward Tamm of the U.S. Court of Appeals for the D.C. Circuit. He holds a Juris Doctorate degree from the University of Virginia School of Law and a Bachelor of Arts degree in economics from the University of Virginia College of Arts and Sciences.

All executive officers are elected at the Annual Meeting of the Board of Directors for one-year terms or until their successors are duly elected. There are no arrangements between any officer and any other person pursuant to which he was selected as an officer. There is no family relationship between any of our executive officers or between any of them and our directors.

The definitive proxy statement to holders of our common stock in connection with the solicitation of proxies to be used in voting at the Annual Meeting of Stockholders to be held on or about May 20, 2014 (the "Proxy Statement"), is hereby incorporated by reference for the purpose of providing information about our directors, and for discussion of our audit committee and our audit committee financial expert. We refer you to the sections "Proposal No. 1: Election of Directors" and "Share Ownership of Management, Directors and Nominees" in the Proxy Statement for information concerning our directors. We refer you to the section "Corporate Governance – Committees of the Board of Directors" in the 2014 Proxy Statement for discussion of our audit committee and our audit committee financial expert. Information concerning our executive officers is presented in Part I of this Form 10-K. We refer you to the section "Section 16(a) Beneficial Ownership Reporting Compliance" in the Proxy Statement for information relating to compliance with Section 16(a) of the Exchange Act.

Southwestern Energy has adopted a code of ethics that applies to our Chief Executive Officer, Chief Financial Officer and Controller as well as other officers and employees. The full text of such code of ethics has been posted on our website at www.swn.com, and is available free of charge in print to any stockholder who requests it. Requests for copies should be addressed to the Secretary at 2350 N. Sam Houston Parkway East, Suite 125, Houston TX, 77032.

## ITEM 11. EXECUTIVE COMPENSATION

The Proxy Statement is hereby incorporated by reference for the purpose of providing information about executive compensation, compensation committee interlocks and insider participation as well as the Compensation Committee Report. We refer you to the sections "Compensation Discussion & Analysis," "Executive Compensation," "Outside Director Compensation," "Compensation Committee Interlocks and Insider Participation" and "Compensation Committee Report" in the Proxy Statement.

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

The Proxy Statement is hereby incorporated by reference for the purpose of providing information about securities authorized for issuance under our equity compensation plans and security ownership of certain beneficial owners and our management. For information about our equity compensation plans, refer to "Equity Compensation Plans" in our Proxy Statement. Refer to the sections "Security Ownership of Certain Beneficial Owners" and "Share Ownership of Management, Directors and Nominees" in our Proxy Statement for information about security ownership of certain beneficial owners and our management and directors.

## ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The Proxy Statement is hereby incorporated by reference for the purpose of providing information about certain relationships, related transactions and board independence. Refer to the sections "Transactions with Related Persons," “Share Ownership of Management, Directors and Nominees,” and “Compensation Discussion and Analysis” for information about transactions with our executive officers, directors or management and to “Corporate Governance – Director Independence” and “ – Committees of the Board of Directors” for information about director independence.

**ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES**

The Proxy Statement is hereby incorporated by reference for the purpose of providing information about fees paid to the principal accountant and the audit committee’s pre-approval policies and procedures. We refer you to the section “Relationship with Independent Registered Public Accounting Firm” in the Proxy Statement and to Exhibit A thereto for information concerning fees paid to our principal accountant and the audit committee’s pre-approval policies and procedures and other required information.

**PART IV**

**ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES**

(a) (1) The consolidated financial statements of Southwestern Energy and its subsidiaries and the report of independent registered public accounting firm are included in Item 8 of this Form 10-K.

(2) The consolidated financial statement schedules have been omitted because they are not required under the related instructions, or are not applicable.

(3) The exhibits listed on the accompanying Exhibit Index are filed as part of, or incorporated by reference into, this Form 10-K.

## SIGNATURES

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

SOUTHWESTERN ENERGY COMPANY

Dated: February 27, 2014

BY: /s/ R. CRAIG OWEN
R. Craig Owen
Senior Vice President
and Chief Financial Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities indicated on February 27, 2014.

| | |
|---|---|
| /s/ HAROLD M. KORELL<br>Harold M. Korell | Director, Chairman of the Board |
| /s/ STEVEN L. MUELLER<br>Steven L. Mueller | Director, President and Chief Executive Officer |
| /s/ R. CRAIG OWEN<br>R. Craig Owen | Senior Vice President and Chief Financial Officer |
| /s/ JOSH C. ANDERS<br>Josh C. Anders | Vice President, Controller |
| /s/ JOHN D. GASS<br>John D. Gass | Director |
| /s/ CATHERINE A. KEHR<br>Catherine A. Kehr | Director |
| /s/ GREG D. KERLEY<br>Greg D. Kerley | Director |
| /s/ VELLO A. KUUSKRAA<br>Vello A. Kuuskraa | Director |
| /s/ KENNETH R. MOURTON<br>Kenneth R. Mourton | Director |
| /s/ ELLIOTT PEW<br>Elliott Pew | Director |
| /s/ ALAN H. STEVENS<br>Alan H. Stevens | Director |

## EXHIBIT INDEX

| Exhibit Number | Description |
|---|---|
| 3.1 | Amended and Restated Certificate of Incorporation of Southwestern Energy Company. (Incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed May 24, 2010) |
| 3.2* | Amended and Restated Bylaws of Southwestern Energy Company, as amended on February 25, 2014. |
| 4.1 | Form of Common Stock Certificate. (Incorporated by reference to Exhibit 4.4 to the Registrant's Current Report on Form 8-K/A filed August 3, 2006) |
| 4.2 | Certificate of Designation, Preferences and Rights of Series A Junior Participating Preferred Stock, dated April 9, 2009. (Incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed on April 9, 2009) |
| 4.3 | Indenture, dated as of December 1, 1995 between Southwestern Energy Company and The First National Bank of Chicago, as trustee. (Incorporated by reference to Exhibit 4 to Amendment No. 1 to the Registrant's Registration Statement on Form S-3 (File No. 33-63895) filed on November 17, 1995) |
| 4.4 | First Supplemental Indenture between Southwestern Energy Company and J.P. Morgan Trust Company, N.A. (as successor to the First National Bank of Chicago) dated June 30, 2006. (Incorporated by reference to Exhibit 4.2 to the Registrant's Current Report on Form 8-K/A filed August 3, 2006) |
| 4.5 | Second Supplemental Indenture by and among Southwestern Energy Company, SEECO, Inc., Southwestern Energy Production Company, Southwestern Energy Services Company and The Bank of New York Trust Company, N.A., as trustee (as successor to J.P. Morgan Trust Company, N.A.), dated as of May 2, 2008. (Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K/A filed on May 8, 2008) |
| 4.6 | Indenture dated June 1, 1998 by and among NOARK Pipeline Finance, L.L.C. and The Bank of New York. (Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed May 4, 2006) |
| 4.7 | First Supplemental Indenture dated May 2, 2006 by and among Southwestern Energy Company, NOARK Pipeline Finance, L.L.C., and UMB Bank, N.A., as trustee (as successor to the Bank of New York). (Incorporated by reference to Exhibit 4.2 to the Registrant's Current Report on Form 8-K filed May 4, 2006) |
| 4.8 | Second Supplemental Indenture between Southwestern Energy Company and UMB Bank, N.A., as trustee, dated June 30, 2006. (Incorporated by reference to Exhibit 4.3 to the Registrant's Current Report on Form 8-K/A filed August 3, 2006) |
| 4.9 | Third Supplemental Indenture by and among Southwestern Energy Company, SEECO, Inc., Southwestern Energy Production Company, Southwestern Energy Services Company and UMB Bank, N.A., as trustee, dated as of May 2, 2008. (Incorporated by reference to Exhibit 4.2 to the Registrant's Current Report on Form 8-K/A filed on May 8, 2008) |
| 4.10 | Guaranty dated June 1, 1998 by Southwestern Energy Company in favor of The Bank of New York, as trustee, under the Indenture dated as of June 1, 1998 between NOARK Pipeline Finance L.L.C. and such trustee. (Incorporated by reference to Exhibit 4.6 to the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 2005) |
| 4.11 | Indenture dated January 16, 2008 among Southwestern Energy Company, the Guarantors named therein and The Bank of New York Trust Company, N.A., as trustee. (Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed January 16, 2008) |
| 4.12 | Indenture by and among Southwestern Energy Company, SEECO, Inc., Southwestern Energy Production Company, Southwestern Energy Services Company and The Bank of New York Trust Company, N.A., as trustee, dated as of March 5, 2012. (Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed March 6, 2012) |

| | |
|---|---|
| 4.13 | Policy on Confidential Voting of Southwestern Energy Company. (Incorporated by reference to the Appendix of the Registrant's Definitive Proxy Statement (Commission File No. 1-08246) for the 2006 Annual Meeting of Stockholders) |
| 4.14 | Credit Agreement dated December 16, 2013 among Southwestern Energy Company, JPMorgan Chase Bank, NA, Bank of America, N.A., Wells Fargo N.A., The Royal Bank of Scotland PLC, Citibank, N.A. and the other lenders named therein, JPMorgan Chase Bank, NA, as administrative agent. (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed December 17, 2013) |
| 10.1 | Form of Second Amended and Restated Indemnity Agreement between Southwestern Energy Company and each Executive Officer and Director of the Registrant. (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K/A filed August 3, 2006) |
| 10.2 | Form of Executive Severance Agreement between Southwestern Energy Company and each of the Executive Officers of Southwestern Energy Company, effective February 17, 1999. (Incorporated by reference to Exhibit 10.12 of the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 1998) |
| 10.3 | Form of Amendment to Executive Severance Agreement between Southwestern Energy Company and each of the Executive Officers of Southwestern Energy Company prior to 2011. (Incorporated by reference to Exhibit 10.3 to the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 2008) |
| 10.4 | Form of Executive Severance Agreement between Southwestern Energy Company and Executive Officers Post 2011. (Incorporated by reference to Exhibit 10.4 to the Registrant's Annual Report on Form 10-K (Commission File No.1-08426) for the year ended December 31, 2012) |
| 10.5 | Southwestern Energy Company Incentive Compensation Plan. (Incorporated by reference to Exhibit 10.2(b) to the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 1998) |
| 10.6 | Amendment to Southwestern Energy Company Incentive Compensation Plan. (Incorporated by reference to Exhibit 10.5 to the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 2008) |
| 10.7 | Second Amendment to Southwestern Energy Company Incentive Compensation Plan (Incorporated by reference to Exhibit 10.6 to the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 2009) |
| 10.8 | Southwestern Energy Company Supplemental Retirement Plan as amended. (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on February 19, 2008) |
| 10.9 | Southwestern Energy Company Non-Qualified Retirement Plan as amended. (Incorporated by reference to Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed on February 19, 2008) |
| 10.10 | Amendment One to the Southwestern Energy Company Non-Qualified Retirement Plan (Incorporated by reference to Exhibit 10.9 to the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 2009) |
| 10.11 | Southwestern Energy Company 2000 Stock Incentive Plan dated February 18, 2000. (Incorporated by reference to the Appendix of the Registrant's Definitive Proxy Statement (Commission File No. 1-08246) for the 2000 Annual Meeting of Stockholders) |
| 10.12 | Southwestern Energy Company 2002 Employee Stock Incentive Plan, effective October 23, 2002. (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on December 13, 2005) |
| 10.13 | Southwestern Energy Company 2002 Performance Unit Plan, as amended, effective December 8, 2011. (Incorporated by reference to Exhibit 10.4 to the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 2012) |

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|---|---|
| 10.14 | Southwestern Energy Company 2004 Stock Incentive Plan. (Incorporated by reference to Appendix A to the Registrant’s Proxy Statement dated March 29, 2004) |
| 10.15 | Southwestern Energy Company 2013 Incentive Plan. (Incorporated by reference to Annex A of the Registrant’s Proxy Statement filed April 8, 2013) |
| 10.16* | Southwestern Energy Company 2013 Incentive Plan Guidelines for Performance Unit Awards. |
| 10.17 | Southwestern Energy Company 2013 Incentive Plan Guidelines for Annual Incentive Awards. (Incorporated by reference to Exhibit 10.3 to the Registrant’s Quarterly Report on Form 10-Q for the quarter ended June 30, 2013) |
| 10.18 | Southwestern Energy Company 2013 Incentive Plan Form of Incentive Stock Option Award Agreement. (Incorporated by reference to Exhibit 10.4 to the Registrant’s Quarterly Report on Form 10-Q for the quarter ended June 30, 2013) |
| 10.19 | Southwestern Energy Company 2013 Incentive Plan Form of Non-Qualified Stock Option Award Agreement. (Incorporated by reference to Exhibit 10.5 to the Registrant’s Quarterly Report on Form 10-Q for the quarter ended June 30, 2013) |
| 10.20 | Southwestern Energy Company 2013 Incentive Plan Form of Non-Qualified Stock Option Award Agreement for Directors. (Incorporated by reference to Exhibit 10.6 to the Registrant’s Quarterly Report on Form 10-Q for the quarter ended June 30, 2013) |
| 10.21 | Southwestern Energy Company 2013 Incentive Plan Form of Restricted Stock Award Agreement. (Incorporated by reference to Exhibit 10.7 to the Registrant’s Quarterly Report on Form 10-Q for the quarter ended June 30, 2013) |
| 10.22 | Southwestern Energy Company 2013 Incentive Plan Form of Restricted Stock Award Agreement for Directors. (Incorporated by reference to Exhibit 10.8 to the Registrant’s Quarterly Report on Form 10-Q for the quarter ended June 30, 2013) |
| 10.23 | Southwestern Energy Company 2013 Incentive Plan Form of Restricted Stock Unit Award Agreement. (Incorporated by reference to Exhibit 10.9 to the Registrant’s Quarterly Report on Form 10-Q for the quarter ended June 30, 2013) |
| 10.24 | Southwestern Energy Company 2013 Incentive Plan Form of Restricted Stock Unit Award Agreement for Directors. (Incorporated by reference to Exhibit 10.10 to the Registrant’s Quarterly Report on Form 10-Q for the quarter ended June 30, 2013) |
| 10.25 | Form of Incentive Stock Option Agreement for awards prior to December 8, 2005. (Incorporated by reference to Exhibit 10.1 to the Registrant’s Current Report on Form 8-K filed on December 20, 2004) |
| 10.26 | Form of Non-Qualified Stock Option Agreement for non-employee directors for awards prior to December 8, 2005. (Incorporated by reference to Exhibit 10.2 to the Registrant’s Current Report on Form 8-K filed on December 20, 2004) |
| 10.27 | Form of Incentive Stock Option for awards granted on or after December 8, 2005. (Incorporated by reference to Exhibit 10.4 to the Registrant’s Current Report on Form 8-K filed on December 13, 2005) |
| 10.28 | Form of Restricted Stock Agreement for awards granted on or after December 8, 2005. (Incorporated by reference to Exhibit 10.4 to the Registrant’s Current Report on Form 8-K filed on December 13, 2005) |
| 10.29 | Form of Non-Qualified Stock Option Agreement for awards granted on or after December 8, 2005 and through December 8, 2011 (Incorporated by reference to Exhibit 10.4 to the Registrant’s Current Report on Form 8-K filed on December 13, 2005) |
| 10.30 | Form of Non-Qualified Stock Option Agreement for awards granted on or after December 8, 2011. (Incorporated by reference to Exhibit 10.4 to the Registrant’s Annual Report on Form 10-K (Commission File No. 1-08426) for the year ended December 31, 2012) |

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| 10.31 | Master Lease Agreement by and between Southwestern Energy Company and SunTrust Leasing Corporation dated December 29, 2006. (Incorporated by reference to Exhibit 10.22 to the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 2006) |
| 10.32 | Guaranty by and between Southwestern Energy Company and Texas Gas Transmission, LLC, dated as of October 27, 2008. (Incorporated by reference to Exhibit 10.3 to the Registrant's Quarterly Report on Form 10-Q (Commission File No. 1-08246) for the period ended September 30, 2008) |
| 10.33 | Guaranty by and between Southwestern Energy Company and Fayetteville Express Pipeline, LLC dated September 30, 2008 (Incorporated by reference to Exhibit 10.22 to the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 2008) |
| 10.34 | Retirement Letter Agreement dated February 24, 2012 between Southwestern Energy Company and Gene A. Hammons. (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed February 27, 2012) |
| 10.35 | Retirement Agreement dated August 11, 2009 between Southwestern Energy Company and Harold M. Korell. (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on August 14, 2009) |
| 21.1* | List of Subsidiaries. |
| 23.1* | Consent of PricewaterhouseCoopers LLP. |
| 23.2* | Consent of Netherland, Sewell & Associates, Inc. |
| 31.1* | Certification of CEO filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. |
| 31.2* | Certification of CFO filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. |
| 32* | Certification of CEO and CFO furnished pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. |
| 95.1* | Mine Safety Disclosure. |
| 99.1* | Reserve Audit Report of Netherland, Sewell & Associates, Inc., dated January 17, 2013. |
| 101.INS* | Interactive Data File Instance Document |
| 101.SCH* | Interactive Data File Schema Document |
| 101.CAL* | Interactive Data File Calculation Linkbase Document |
| 101.LAB* | Interactive Data File Label Linkbase Document |
| 101.PRE* | Interactive Data File Presentation Linkbase Document |
| 101.DEF* | Interactive Data File Definition Linkbase Document |

*Filed herewith