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, 2011

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 $14,642,400,618 based on the New York Stock Exchange – Composite Transactions closing price on June 30, 2011, of $42.88. For purposes of this calculation, the registrant has assumed that its directors and executive officers are affiliates.

As of February 23, 2012, the number of outstanding shares of the registrant's Common Stock, par value $0.01, was 349,044,745.

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 22, 2012 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, 2011

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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 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, Compensation, Nominating and Governance and Retirement Committees of our Board of Directors are available on our website, and are available in print free of charge to any stockholder upon request.

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.

Exploration and Production - Our primary business is the exploration for and production of natural gas and oil, with our current operations being principally focused within the United States on development of an unconventional gas reservoir located on the Arkansas side of the Arkoma Basin, which we refer to as the Fayetteville Shale play. We are also actively engaged in exploration and production activities 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 also engage in exploration activities in order to test new plays and recently commenced exploration operations in Arkansas and Louisiana relating to an unconventional horizontal oil play targeting the Lower Smackover Brown Dense formation (LSBD). In addition, in 2010, we commenced an exploration program for natural gas and crude oil under 32 licenses in New Brunswick, Canada. We conduct our exploration and production operations through our wholly-owned subsidiaries, SEECO, Inc., or SEECO, and Southwestern Energy Production Company, or SEPCO. SEECO operates exclusively in Arkansas where it holds a large base of both developed and undeveloped gas reserves, and conducts the Fayetteville Shale drilling program and the conventional Arkoma Basin drilling program in the Arkoma Basin. SEPCO conducts development drilling and exploration programs in Pennsylvania, Oklahoma, Texas, Arkansas and Louisiana. DeSoto Drilling, Inc., or DDI, a wholly-owned subsidiary of SEPCO, operates drilling rigs in Arkansas, Pennsylvania and Louisiana, as well as our other operating areas. Our Canadian operations are conducted by our subsidiary, SWN Resources Canada Inc.

Midstream Services - We engage in natural gas gathering activities in Arkansas, Texas and Pennsylvania through our gathering subsidiaries, DeSoto Gathering Company, L.L.C., which we refer to as DeSoto Gathering, and Angelina Gathering Company, L.L.C., which we refer to as Angelina Gathering. DeSoto Gathering and Angelina Gathering primarily support our E&P operations and generate revenue from gathering fees associated with the transportation of our and third party gas to market. Our natural gas marketing subsidiary, Southwestern Energy Services Company, or SES, captures downstream opportunities which 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, or EBITDA, is derived from our E&P business. In 2011, 77% of our operating income and 84% of our EBITDA were generated from our E&P business, compared to 81% of our operating income and 86% of our EBITDA in 2010, and 86% of our operating income and 90% of our EBITDA in 2009, absent our $907.8 million, or $558.3 million net of taxes, non-cash ceiling test impairment of our natural gas and oil properties. In 2011, 23% of our operating income and 16% of our EBITDA were generated from Midstream Services, compared to 19% of our operating income and 14% of our EBITDA in 2010, and 14% of our operating income and 10% of our EBITDA in 2009, absent the non-cash ceiling test impairment of our natural gas and oil properties. 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 EBITDA to net income (loss) attributable to Southwestern Energy.

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:

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

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 present value added for each dollar to be invested, which we refer to as Present Value Index, or PVI. The PVI of the future expected cash flows for each project is determined using a 10% discount rate. We target creating at least $1.30 of discounted 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.* Our primary focus is to maximize the value of our significant acreage position in the Fayetteville Shale play, which has provided significant production and reserve growth since we began drilling in the play in 2004. At December 31, 2011, we held approximately 925,842 net acres in the Fayetteville Shale play and the area accounted for approximately 87% of our total proved oil and natural gas reserves and approximately 87% of our total oil and natural gas production during 2011. Additionally, we are actively drilling on portions of our 186,893 net acres in the Marcellus Shale and believe our production and reserves from this play will grow substantially over the next few years. We intend to further develop our acreage positions in the Fayetteville Shale and the Marcellus Shale and 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, which we refer to as "New Ventures." 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. As of December 31, 2011, we held 3,600,314 net undeveloped acres in connection with our New Ventures prospects, including 2,518,518 net acres in New Brunswick and 520,619 net undeveloped acres in the LSBD formation in southern Arkansas and northern Louisiana.

- *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 enhancing, drilling, completing and producing of wells and the marketing of production to minimize costs and maximize both production volumes and realized price. In our Fayetteville Shale play, we have achieved significant cost savings by operating a fleet of drilling rigs designed specifically for the play and from our other associated oilfield services including our sand mine that is a source of proppant for our well completions. During 2012, we plan to commence providing pressure pumping services for certain of our operated well completions.

- *Enhancing the Value of Our Midstream Operations.* We have continued to design and improve our gas gathering infrastructure to better manage the physical movement of our production and the costs of our operations. As of December 31, 2011, we have invested approximately $933.0 million in the 1,791 mile gas gathering system built for our Fayetteville Shale play, which was gathering approximately 2.1 Bcf per day at year-end, and have invested approximately $44.2 million in 38 miles of gas gathering lines in East Texas and Pennsylvania. Our gathering system for the Fayetteville Shale play has developed into a strategic asset that not only supports our E&P operations but also will increase our overall returns on a standalone basis.

Recent Developments

2012 Planned Capital Investments and Production Guidance. Our planned capital investment program for 2012 is approximately $2.1 billion, which includes approximately $1.8 billion for our E&P segment, $190 million for our Midstream Services segment and $90 million for corporate and other purposes. Our 2012 capital program is expected to be primarily funded by our cash flow from operations and borrowings under our $1.5 billion revolving credit facility. The planned capital program for 2012 is flexible and we will reevaluate our proposed investments as needed to take into account prevailing market conditions. Based on our capital program, we also announced our targeted 2012 natural gas and oil production of approximately 560 to 570 Bcfe, an increase of approximately 13% over our 2011 production, using midpoints.

Exploration and Production

Overview

Our operations are primarily focused on the Fayetteville Shale, an unconventional reservoir located in the Arkoma Basin in Arkansas. In addition to our Arkansas operations, we are also continuing to expand our drilling program on our acreage in Pennsylvania targeting the Marcellus Shale and we will conduct both conventional and unconventional operations targeting various formations as part of our New Ventures projects, which include the recently announced unconventional horizontal oil plays targeting the Brown Dense formation in Arkansas and Louisiana, and exploration activities in New Brunswick, Canada. We continue to actively seek to 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 $825.1 million in 2011. Our E&P segment recorded operating income of $829.5 million in 2010 and an operating loss of $157.7 million in 2009 as a result of the recognition of a $907.8 million, or $558.3 million net of taxes, non-cash ceiling test impairment of our natural gas and oil properties recorded for the three months ended March 31, 2009. The slight decrease in operating income in 2011 was primarily due to lower prices realized from the sale of our natural gas production and an increase in operating costs and expenses which was largely offset by a 24% increase in our total natural gas and oil production. The increase in operating income in 2010 was primarily due to a 35% increase in our total natural gas and oil production which was partially offset by lower prices realized from the sale of our natural gas production and an increase in operating costs and expenses. EBITDA from our E&P segment was $1.5 billion in 2011, compared to $1.4 billion in 2010 and $1.2 billion in 2009. The increase in our EBITDA in 2011 was due to our increased production volumes which was partially offset by lower prices realized from the sale of our natural gas production and increased operating costs and expenses. The increase in our EBITDA in 2010 was due to our increased production volumes which was partially offset by lower prices realized from the sale of our natural gas production and increased operating costs and expenses. 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 EBITDA to net income (loss) attributable to Southwestern Energy.

Our Proved Reserves

Our estimated proved natural gas and oil reserves were 5,893 Bcfe at year-end 2011, compared to 4,937 Bcfe at year-end 2010 and 3,657 Bcfe at year-end 2009. The overall increase in total estimated proved reserves in the past three years is primarily due to the development of the Fayetteville Shale play in Arkansas, with the development of the Marcellus Shale play in Pennsylvania also contributing in 2011. The average prices utilized to value our estimated proved natural gas and oil reserves at December 31, 2011 were $4.12 per MMBtu for natural gas and $92.71 per barrel for oil compared to $4.38 per MMBtu for natural gas and $75.96 per barrel for oil at December 31, 2010 and $3.87 per MMBtu for natural gas and $57.65 per barrel for oil at December 31, 2009.

The after-tax PV-10, or standardized measure of discounted future net cash flows relating to proved gas and oil reserve quantities, was $3.5 billion at year-end 2011, compared to $3.0 billion at year-end 2010 and $1.8 billion at year-end 2009. The increase in our after-tax PV-10 value in 2011 was primarily due to the increase in our reserves, partially offset by a comparative decrease in average 2011 prices for natural gas from average 2010 prices. The increase in our after-tax PV-10 value in 2010 was primarily due to the increase in our reserves and a comparative increase in average 2010 prices for natural gas from average 2009 prices, partially offset by higher operating and future development costs. Our proved reserves are almost entirely natural gas and as such the after-tax PV-10 measure is highly dependent upon the natural gas price used in the after-tax PV-10 calculation. The reconciling difference in after-tax PV-10 and pre-tax PV-10 (a non-GAAP measure which is reconciled in the 2011 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 2011 estimated proved reserves had a present value of estimated future net cash flows before income tax, or pre-tax PV-10, of $4.8 billion, compared to $4.3 billion at year-end 2010 and $2.3 billion at year-end 2009.

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.

Approximately 100% of our year-end 2011and 2010 estimated proved reserves were natural gas and 55% were classified as proved developed, compared to 100% and 54%, respectively, in 2009. We operate approximately 96% of our reserves, based on the pre-tax PV-10 value of our proved developed producing reserves, and our reserve life index approximated 11.8 years at year-end 2011. Sales of natural gas production accounted for nearly 100% of total operating revenues for this segment in 2011, 99% in 2010 and 100% in 2009.

The following table provides an overall and by category summary of our oil and natural gas reserves, as of fiscal year-end 2011 based on average fiscal year prices, and our well count, net acreage and PV-10 as of December 31, 2011 and sets forth 2011 annual information related to production and capital investments for each of our operating areas:

2011 PROVED RESERVES BY CATEGORY AND SUMMARY OPERATING DATA

	Fayetteville Shale Play	Marcellus Shale Play	Ark-La-Tex East Texas	Ark-La-Tex Arkoma Basin	New Ventures	Total
Estimated Proved Reserves:						
Natural Gas (Bcf):						
Developed (Bcf)	2,689	172	220	173	—	**3,254**
Undeveloped (Bcf)	2,415	170	27	21	—	**2,633**
	5,104	342	247	194	—	**5,887**
Crude Oil (MMBbls):						
Developed (MMBbls)	—	—	1	—	—	**1**
Undeveloped (MMBbls)	—	—	—	—	—	—
	—	—	1	—	—	**1**
Total Proved Reserves (Bcfe)[(1)]:						
Proved Developed (Bcfe)	2,689	172	226	173	—	**3,260**
Proved Undeveloped (Bcfe)	2,415	170	27	21	—	**2,633**
	5,104	342	253	194	—	**5,893**
Percent of Total	87%	6%	4%	3%	—	**100%**
Percent Proved Developed	53%	50%	89%	89%	—	**55%**
Percent Proved Undeveloped	47%	50%	11%	11%	—	**45%**
Production (Bcfe)	436.8	23.4	23.5	16.3	—	**500.0**
Capital Investments (millions)[(2)]	$ 1,347	$ 332	$ 68	$ 8	$ 201	**$ 1,956**
Total Gross Producing Wells	2,735	30	602	1,185	—	**4,552**
Total Net Producing Wells	1,856	22	459	574	—	**2,911**
Total Net Acreage	800,786[(3)]	186,893[(4)]	91,082[(5)]	319,550[(6)]	3,600,314[(7)]	**4,998,625**
Net Undeveloped Acreage	360,473[(3)]	180,676[(4)]	27,281[(5)]	138,191[(6)]	3,600,314[(7)]	**4,306,935**
PV-10:						
Pre-tax (millions)[(8)]	$ 3,806	$ 511	$ 260	$ 226	$ —	**$ 4,803**
PV of taxes (millions)[(8)]	1,071	144	73	64	—	**1,352**
After-tax (millions)[(8)]	$ 2,735	$ 367	$ 187	$ 162	$ —	**$ 3,451**
Percent of Total	79%	11%	5%	5%	—	**100%**
Percent Operated[(9)]	96%	99%	98%	87%	—	**96%**

(1) We have no reserves from synthetic gas, synthetic oil or nonrenewable natural resources intended to be upgraded into synthetic gas or oil. Our proved reserves increased by 1,459.4 Bcfe as a result of our drilling program and net upward revisions of 33.7 Bcfe in 2011. Of the reserve additions, 611.6 Bcfe were proved developed and 847.8 Bcfe were proved undeveloped. 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 play capital investments exclude $21 million related to our drilling rig related equipment, sand facility and other equipment.

(3) Assuming successful wells are not drilled to develop the acreage and leases are not extended, leasehold expiring over the next three years will be 2,804 net acres in 2012, 208,563 net acres in 2013, which includes 184,696 net acres held on federal lands, and 23,800 net acres in 2014.

(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 58,210 net acres in 2012, 44,551 net acres in 2013 and 10,071 net acres in 2014.

(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 380 net acres in 2012, 790 net acres in 2013 and 77 net acres in 2014.

(6) Includes 123,442 net developed acres and 1,614 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 30,025 net acres in 2012, 2,181 net acres in 2013 and 31,769 net acres in 2014.

(7) Assuming successful wells are not drilled to develop the acreage and leases are not extended, leasehold expiring over the next three years, excluding New Brunswick, Canada and the LSBD area will be 1,200 net acres in 2012, 1,200 net acres in 2013 and 31,600 net acres in 2014. With regard to the company's acreage in New Brunswick, Canada, assuming the options are not extended/exercised by March 2013 then, in such event, 2,518,518 net acres will expire in 2013. With regard to the LSBD acreage, assuming successful wells are not drilled and leases are not extended, leasehold expiring over the next three years will be 15,860 net acres in 2012, 64,120 net acres in 2013 and 228,660 net acres in 2014.

(8) 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.

(9) 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

As of December 31, 2011, we had 2,633 Bcfe of proved undeveloped reserves, none of which were proved undeveloped reserves that remain undeveloped for five years or more after initially being disclosed by us. During 2011, we invested $509.3 million in connection with converting 403.3 Bcfe or 18% of our proved undeveloped reserves as of December 31, 2010 into proved developed reserves and added 847.8 Bcfe of proved undeveloped reserve additions, primarily in the Fayetteville Shale play. Our 2011 proved undeveloped reserve additions are expected to be developed and to begin to generate cash inflows over the next five years. At December 31, 2010, we had 2,243 Bcfe of proved undeveloped reserves, none of which were proved undeveloped reserves that remained undeveloped for five years or more after initially being disclosed by us. During 2010, we invested $312.4 million in connection with converting 213.1 Bcfe or 13% of our proved undeveloped reserves as of December 31, 2009 into proved developed reserves and added 733.2 Bcfe of proved undeveloped reserve additions, primarily in the Fayetteville Shale play.

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 2,633 Bcfe as of December 31, 2011 will require us to invest an additional $3.4 billion in order 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 affect on us," "We may have difficulty financing our planned capital investments, which could adversely affect our growth" and "Our future 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 ability of an E&P company to add new reserves to replace the reserves that are being depleted by its current production volumes is viewed by many investors as an indication of its long-term prospects. The reserve replacement ratio, which we discuss below, is an important analytical measure used within the E&P industry by investors and peers to evaluate performance results. 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. Our reserve replacement ratio, including revisions, has averaged over 400% for the three year period ended December 31, 2011, primarily driven by increases in the reserves associated with our Fayetteville Shale play with the development of the Marcellus Shale play in Pennsylvania also contributing in 2011.

In 2011, we replaced 299% of our production volumes with an increase of 1,459.4 Bcfe of proved gas and oil reserves as a result of our drilling program and net upward revisions of 33.7 Bcfe. Of the reserve additions, 611.6 Bcfe were proved developed and 847.8 Bcfe were proved undeveloped. The upward reserve revisions during 2011 were primarily due to 102.6 Bcf in upward revisions related to the improved performance of wells in our Marcellus Shale play, partially offset by downward performance revisions of 27.5 Bcfe and 18.2 Bcfe in our east Texas and conventional Arkoma Basin operating areas, respectively. We also had downward performance revisions in our Fayetteville Shale play of 14.0 Bcfe. Additionally, our reserves decreased by 9.2 Bcfe due to a comparative decrease in the average gas price for 2011 as compared to 2010. In addition, our reserves decreased by 37.3 Bcfe as a result of our sale of oil and natural gas leases and wells in 2011.

In 2010, we replaced 430% of our production volumes with an increase of 1,431.1 Bcfe of proved gas and oil reserves as a result of our drilling program and net upward revisions of 309.6 Bcfe. Of the reserve additions, 698.0 Bcfe were proved developed and 733.2 Bcfe were proved undeveloped. The upward reserve revisions during 2010 were primarily due to 266.7 Bcf in upward revisions related to the improved performance of wells in our Fayetteville Shale play and positive reserve revisions of 78.4 Bcfe due to a comparative increase in the average gas price for 2010 as compared to 2009. Additionally, we had net upward revisions of 2.7 Bcfe and 34.2 Bcf in our East Texas and conventional Arkoma Basin operating areas, respectively. Additionally, our reserves decreased by 55.4 Bcfe as a result of our sale of oil and natural gas leases and wells in 2010.

In 2009, our reserve replacement ratio was 592% with an increase of 1,685.2 Bcfe of proved natural gas and oil reserves as a result of our drilling program and net upward revisions of 92.9 Bcfe. Of the 2009 reserve additions, 757.6 Bcfe were proved developed and 927.5 Bcfe were proved undeveloped. The upward reserve revisions during 2009 were primarily due to 384.8 Bcf in upward revisions related to the improved performance of wells in our Fayetteville Shale play, partially offset by downward reserve revisions of 251.5 Bcf due to a comparative decrease in the average gas price for 2009 as compared to year-end 2008. Additionally, we had downward performance revisions of 25.5 Bcfe and 15.1 Bcf in our East Texas and conventional Arkoma Basin operating areas, respectively.

For the period ending December 31, 2011, our three-year average reserve replacement ratio, including revisions, was 416%. Our reserve replacement ratio for 2011, excluding the effect of reserve revisions, was 292%, compared to 354% in 2010 and 561% in 2009. Excluding reserve revisions, our three-year average reserve replacement ratio is 380%.

Since 2005, the substantial majority of our reserve additions have been generated from our drilling program in the Fayetteville Shale play. We expect our drilling programs in the Fayetteville Shale and Marcellus Shale plays to continue 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 Marcellus Shale plays 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 Play

Our Fayetteville Shale play is currently a primary focus of our E&P 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. The Barnett Shale found in north Texas is an analogous reservoir. At December 31, 2011, we held leases for approximately 925,842 net acres in the play area (360,473 net undeveloped acres, 440,313 net developed acres held by Fayetteville Shale production, 123,442 net developed acres held by conventional production and the remainder in the traditional Fairway portion of the Arkoma Basin), compared to approximately 915,884 net acres at year-end 2010 and 888,695 net acres at year-end 2009.

Approximately 5,104 Bcf of our reserves at year-end 2011 were attributable to our Fayetteville Shale play, compared to approximately 4,345 Bcf at year-end 2010 and 3,117 Bcf at year-end 2009. Gross production from our operated wells in the Fayetteville Shale play increased from approximately 1,635 MMcf per day at the beginning of 2011 to approximately 1,947 MMcf per day by year-end. Our net production from the Fayetteville Shale play was 436.8 Bcf in 2011, compared to 350.2 Bcf in 2010 and 243.5 Bcf in 2009. In 2012, we estimate our production from the Fayetteville Shale play will be in the range of 465 to 470 Bcf.

At year-end 2011, approximately 74% of our 597,482 total net leasehold acres in the Fayetteville Shale was held by production, excluding our acreage in the traditional Fairway and the federal acreage we hold in the Ozark Highlands Unit. 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 traditional Fairway, our acreage position was obtained at an average cost of approximately $253 per acre and has an average royalty interest of 15%. In 2012, we will earn 2 sections or approximately 500 net acres, representing less than 1% of our drilling program. As of December 31, 2011, excluding our acreage in the traditional Fairway and our federal acreage, the undeveloped portion of our acreage had an average remaining lease term of 2 years.

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.

As of December 31, 2011, we had spud a total of 3,095 wells in the play since its commencement in 2004, 2,581 of which were operated by us and 514 of which were outside-operated wells. Of the wells spud, 650 were in 2011, 658 were in 2010 and 570 were in 2009. Of the wells spud in 2011, 649 were designated as horizontal wells. At year-end 2011, 2,380 operated wells had been drilled and completed overall, including 2,290 horizontal wells. Of the 2,290 horizontal wells, 2,272 wells were fracture stimulated using either slickwater or crosslinked gel stimulation treatments, or a combination thereof.

Over the past several years, we have seen continual improvement in our drilling practices in the Fayetteville Shale play. Our operated horizontal wells had an average completed well cost of $2.8 million per well, average horizontal lateral length of 4,836 feet and average time to drill to total depth of 8 days from re-entry to re-entry in 2011. This compares to an average completed operated well cost of $2.8 million per well, average horizontal lateral length of 4,528 feet and average time to drill to total depth of 11 days from re-entry to re-entry during 2010. In 2009, our average completed operated well cost was $2.9 million per well with an average horizontal lateral length of 4,100 feet and average time to drill to total depth of 12 days from re-entry to re-entry. The operated wells we placed on production during 2011 averaged initial production rates of 3,330 Mcf per day, compared to average initial production rates of 3,364 Mcf per day in 2010-and 3,478 Mcf per day in 2009. The decrease in initial production rates in 2011 and 2010 are primarily due to increased well density and locational differences in the mix of wells. During 2011, we placed 51 operated wells on production with initial production rates that exceeded 5.0 MMcf per day, including 6 wells that exceeded 6.0 MMcf per day.

Beginning in late 2008 and continuing through 2011, we drilled a significant number of wells to test tighter well spacing. At December 31, 2011, we had placed 1,123 wells on production that have well spacing of 700 feet or less, representing approximately 65-acre spacing or less. Early production performance from recent well spacing tests suggests that there are areas of the field that may be economically developed at tighter spacing depending on market conditions.

Our total proved net reserves booked in the play at year-end 2011 were 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. Of the 4,376 locations, 4,310 were horizontal. The average gross proved reserves for the undeveloped wells included in our year-end 2011 and 2010 reserves was approximately 2.4 Bcf per well, compared to 2.2 Bcf per well at year-end 2009. Total proved net gas reserves booked in the play in 2010 totaled approximately 4,345 Bcf from a total of 3,682 locations, of which 2,120 were proved developed producing, 36 were proved developed non-producing and 1,526 were proved undeveloped. Total proved net gas reserves booked in the play in 2009 totaled approximately 3,117 Bcf from a total of 2,675 locations, of which 1,428 were proved developed producing, 97 were proved developed non-producing and 1,150 were proved undeveloped. If the Fayetteville Shale play continues to be successfully developed, we expect a continued significant level of proved reserves in the Fayetteville Shale play over the next few years.

In 2011, we invested approximately $1.3 billion in our Fayetteville Shale play, which included approximately $1.2 billion to spud 650 wells, 580 of which we operated. We increased our reserves in the Fayetteville Shale play by 1,196 Bcf, which included net downward reserve revisions of 15 Bcf due primarily to well performance of 14 Bcf and downward price revisions of 1 Bcf. Included in our total capital investments in the play during 2011 was $132 million in capitalized costs and other expenses and $10 million for acquisition of properties. In 2010, we invested approximately $1.3 billion in our Fayetteville Shale play, which included $1.2 billion to spud 658 wells, $48 million for acquisition of properties, and $111 million in capitalized costs and other expenses. In 2009, we invested approximately $1.3 billion in our Fayetteville Shale play, which included $1.1 billion to spud 570 wells, $40 million for acquisition of properties, $22 million for seismic and $106 million in capitalized costs and other expenses. At December 31, 2011, 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 traditional Fairway portion of the Arkoma Basin.

In 2012, we plan to invest approximately $1.1 billion in our Fayetteville Shale play, which includes participating in approximately 460 to 470 gross wells, 425 to 435 of which are planned to be operated by us.

We believe that our Fayetteville Shale acreage continues to have significant development potential. Our strategy going forward is to increase our production through 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 play 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 are subject to change" in Item 1A of Part I of this Form 10-K.

Marcellus Shale Play

We began leasing in northeastern Pennsylvania in 2007 in an effort to gain a position in the emerging Marcellus Shale play. At December 31, 2011, we had approximately 186,893 net acres in Pennsylvania under which we believe the Marcellus Shale is prospective (180,676 net undeveloped acres and 6,217 net developed acres held by production), compared to approximately 173,009 net acres at year-end of 2010 and 149,317 net acres at year-end 2009. The increase in our acreage during 2011 and 2010 was primarily due to the acquisition of additional leasehold. Our undeveloped acreage position as of December 31, 2011 had an average remaining lease term of 2 years, an average royalty interest of 13% and was obtained at an average cost of approximately $1,077 per acre.

As of year-end 2011, we had spud 70 wells, 23 of which were on production and 67 of which were horizontal wells. In 2011, we invested approximately $332 million in the Marcellus Shale, which included approximately $214 million to participate in 45 wells, of which 8 are on production and 37 were in progress at year-end. Of these 45 wells, 18 were horizontal wells located in our Greenzweig area in Bradford County and the remaining 27 wells were located in our Price and Range Trust areas in Susquehanna County. At December 31, 2011, the Company had 22 operated horizontal wells on production which had an average completed well cost of $6.4 million per well, average horizontal lateral length of 4,007 feet and an average of 12 fracture stimulation stages. Included in our total capital investments in the play during 2011 was approximately $77 million for acquisition of properties, $13 million for seismic and $29 million in capitalized costs and other expenses. In 2011, we began the year drilling with one operated rig in Pennsylvania and ended the year with two operated rigs.

Approximately 342 Bcf of our total proved net reserves at year-end 2011 were attributable to the Marcellus Shale. The company had a total of 22 operated horizontal wells and 1 operated vertical well which were on production at December 31, 2011, resulting in net production from this area of 23.4 Bcf in 2011, compared to 1.0 Bcf in 2010. Our reserves booked in the Marcellus Shale included 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 was approximately 7.5 Bcf per well, up from 3.0 per well at year-end 2010. In 2010, we invested approximately $118 million in the Marcellus Shale and participated in 21 wells, resulting in net production of 1.0 Bcf and adding new reserves of 38 Bcf. In 2009, we invested approximately $40 million in the Marcellus Shale, substantially all of which was for the acquisition of properties.

In 2012, we plan to invest approximately $526 million. We expect to end the year with four operated rigs and participate in a total of 80 to 85 gross wells in 2012, all of which will be operated by us. In 2012, we estimate our production from the Marcellus Shale play will be in the range of 60 to 65 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/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." 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 our Marcellus Shale play 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 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 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 39.8 Bcfe in 2011, compared to 53.5 Bcfe in 2010 and 56.9 Bcfe in 2009. The decline in production from these areas during 2011 and 2010 was primarily driven by asset dispositions as well as natural field production declines and lower capital investments in these areas since

2009. In May 2011, we sold the producing rights to the Haynesville and Middle Bossier Shale intervals in approximately 9,717 net acres for approximately $118.1 million. In June 2010, we sold the producing rights to the Haynesville and Middle Bossier Shale intervals in approximately 20,063 net acres for approximately $357.8 million. We expect these sales, together with our planned decrease in capital investments and the natural production decline in existing wells, to decrease our net production from East Texas in 2012. In 2011, we invested approximately $76 million in East Texas and Arkoma and participated in 10 wells, adding new reserves of 19 Bcfe. Total proved net reserves from these areas were approximately 447 Bcfe at December 31, 2011, compared to 554 Bcfe at year-end 2010 and 538 Bcfe at year-end 2009. In 2012, we expect to invest approximately $18 million combined in our East Texas and Conventional Arkoma Basin programs.

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 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 repeatability, 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, 2011, we held 3,600,314 net undeveloped acres in connection with our New Ventures prospects, of which 2,518,518 net acres were located in New Brunswick, Canada and 520,619 net acres related to the Lower Smackover Brown Dense (LSBD) in southern Arkansas and northern Louisiana. This compares to 3,009,643 net undeveloped acres held at year-end 2010, of which 2,518,518 net acres were located in New Brunswick, Canada, and 36,125 net undeveloped acres held at year-end 2009.

In 2010, we successfully bid for exclusive licenses from the Department of Natural Resources of the Province of New Brunswick, Canada to search and conduct an exploration program covering over 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 USD in the province by March 31, 2013. During 2011 and 2010, we conducted airborne gravity and magnetics surveys, surface geochemistry surveys and, as of December 31, 2011, had acquired 248 miles of 2-D seismic data. While preliminary interpretation has already begun, in 2012 we intend to continue our acquisition of approximately 130 additional miles of 2-D seismic data and plan to drill two stratigraphic well tests in the fourth quarter of 2012. Through December 31, 2011, we have invested approximately $24.0 million in our New Brunswick exploration program, which represents our first venture outside of the United States.

In July 2011, we announced that we would begin testing a new unconventional horizontal oil play targeting the LSBD formation, an unconventional oil 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. At December 31, 2011, we held approximately 520,619 net undeveloped acres in the area, obtained at an average cost of $375 per acre. Our leases currently have an 82% average net revenue interest and an average primary lease term of 4 years, which may be extended for an additional 4 years. The LSBD formation is an Upper Jurassic age, kerogen-rich carbonate source rock found across the Gulf Coast region of the southern United States from Texas to Florida. We extensively reviewed the LSBD across the region and believe that the right mix of reservoir depth, thickness, porosity, matrix permeability, sealing formations, thermal maturity and oil characteristics are found in our leased areas and that the formation compares favorably to other productive oil plays in the United States. In February 2012, we completed our first well in the play area, the Roberson 18-19 #1-15H located in Columbia County, Arkansas, at a total depth of approximately 9,369 feet and a horizontal lateral length of approximately 3,600 feet. Our second well, the Garrett 7-23-5H #1 located in Claiborne Parish, Louisiana, was drilled to a vertical depth in February 2012 at approximately 10,863 feet with a 6,536-foot horizontal lateral and is expected to be completed in March 2012. If our drilling program yields positive results, we expect that activity in the play could increase significantly over the next several years.

While we believe that our New Ventures projects have significant exploration and exploitation potential, there can be no assurance that all 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 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.

Divestitures

In May 2011, we sold certain oil and natural gas leases, wells and gathering equipment in East Texas for approximately $118.1 million. The sale included only the producing rights to the Haynesville and Middle Bossier Shale intervals in approximately 9,717 net acres. The net production from the Haynesville and Middle Bossier Shale intervals in this acreage was approximately 7.0 MMcf per day and proved net reserves were approximately 37.1 Bcf when the sale was closed in May 2011.

In June 2010, we sold certain oil and natural gas leases, wells and gathering equipment in East Texas for approximately $357.8 million. The sale included only the producing rights to the Haynesville and Middle Bossier Shale intervals in approximately 20,063 net acres. The net production from the Haynesville and Middle Bossier Shale intervals in this acreage was approximately 13.5 MMcf per day and proved net reserves were approximately 55.4 Bcf when the sale was closed in June 2010.

Capital Investments

During 2011, we invested a total of $2.0 billion in our E&P business and participated in drilling 708 wells, 447 of which were successful, and 261 which were in progress at year-end. Of the 261 wells in progress at year-end, 214 were located in our Fayetteville Shale play. Of the approximately $2.0 billion invested in our E&P business in 2011, approximately $1.3 billion was invested in our Fayetteville Shale play, $332 million in our Marcellus Shale play, $68 million in East Texas, $8 million in our conventional Arkoma Basin program and $201 million in New Ventures projects.

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 other expenses. Additionally, we invested approximately $21 million in our drilling rig related equipment, sand facility and other equipment. In 2010, we invested approximately $1.8 billion in our primary E&P business activities and participated in drilling 713 wells. Of the $1.8 billion invested in 2010, approximately $1.4 billion was invested in exploratory and development drilling and workovers, $200 million for acquisition of properties, $17 million for seismic expenditures and $172 million in capitalized interest and expenses and other technology-related expenditures. Additionally, we invested approximately $13 million in our drilling rig related equipment, sand facility, and other equipment. In 2009, we invested approximately $1.6 billion in our primary E&P business activities and participated in drilling 750 wells. Of the $1.6 billion invested in 2009, approximately $1.3 billion was invested in exploratory and development drilling and workovers, $82 million for acquisition of properties, $32 million for seismic expenditures and $155 million in capitalized interest and expenses and other technology-related expenditures. Additionally, we invested approximately $35 million in drilling rig related and ancillary equipment.

In 2012, we plan to invest approximately $1.8 billion in our E&P program and participate in drilling 555 to 565 gross wells, 510 to 530 of which are planned to be operated by us. The Fayetteville Shale play will be the primary focus of our capital investments, with planned investments of approximately $1.1 billion. Our planned 2012 capital investments also include approximately $526 million associated with increased Marcellus Shale play activity, $177 million in unconventional, exploration and New Ventures projects and $18 million combined investments in East Texas and our conventional drilling program in the Arkoma Basin.

Of the $1.8 billion allocated to our 2012 E&P capital budget, approximately $1.5 billion will be invested in development and exploratory drilling, $20 million in seismic and other geological and geophysical expenditures, $75 million in acquisition of properties and $300 million in capitalized interest and expenses as well as equipment, facilities and technology-related expenditures. 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 2012.

Sales, Delivery Commitments and Customers

Sales. Our daily natural gas equivalent production averaged 1,370.0 MMcfe in 2011, compared to 1,108.8 MMcfe in 2010 and 823.1 MMcfe in 2009. Total natural gas equivalent production was 500.0 Bcfe in 2011, up from 404.7 Bcfe in 2010 and 300.4 Bcfe in 2009. Our natural gas production was 499.4 Bcf in 2011, compared to 403.6 Bcf in 2010 and 299.7 Bcf in 2009. The increase in production in 2011 resulted primarily from a 86.6 Bcf increase in net production from our Fayetteville Shale play and a 22.4 Bcf increase in net production from our Marcellus Shale play, which more than offset a combined 13.7 Bcfe decrease in net production from our East Texas and Arkoma Basin properties. The increase in production in 2010 resulted primarily from a 106.7 Bcf increase in production from the Fayetteville Shale play and an increase in our East Texas production, which more than offset a combined 3.4 Bcfe decrease in net production from our East Texas and Arkoma Basin properties. We also produced 97,000 barrels of oil in 2011, compared to 171,000 barrels of oil in 2010 and 124,000 barrels of oil in 2009. Our oil production has decreased between 2011 and 2010 primarily due to the natural production decline in existing wells. For 2012, we are targeting total natural gas and crude oil production of approximately 560 to 570 Bcfe, which represents a growth rate of approximately 13% over our 2011 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 crude oil production in order 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. At December 31, 2011, we had NYMEX commodity price hedges in place on 266.4 Bcf, or approximately 47% of our targeted 2012 natural gas production and 185.2 Bcf of our expected 2013 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 at December 31, 2011.

Including the effect of hedges, we realized an average wellhead price of $4.19 per Mcf for our natural gas production in 2011, compared to $4.64 per Mcf in 2010 and $5.30 per Mcf in 2009. Our hedging activities increased our average gas price $0.63 per Mcf in 2011, increased our average gas price $0.71 per Mcf in 2010 and increased our average price $1.96 per Mcf in 2009. Our average oil price realized was $94.08 per barrel in 2011, compared to $76.84 per barrel in 2010 and $54.99 per barrel in 2009. None of our crude oil production was hedged during 2011, 2010 or 2009.

During 2011, the average price received for our natural gas production, excluding the impact of hedges, was approximately $0.48 Mcf lower than average NYMEX prices. Assuming a NYMEX commodity price for 2012 of $3.00 per Mcf of natural gas, the average price received for our natural gas production is expected to be approximately $0.15 to $0.20 per Mcf below the NYMEX Henry Hub average settlement price, including the impact of our basis hedges. Our E&P segment receives a sales price for our natural gas at a discount to NYMEX settlement prices due to locational basis differentials, while transportation charges and fuel charges also reduce the price received. In 2012, we expect to pay average third-party transportation charges in the range of $0.25 to $0.30 per Mcf and average fuel charges in the range of 0.50% to 1.00% of our sales price for natural gas. In 2012, we expect to receive an average natural gas sales price of approximately $0.45 to $0.55 less than the average NYMEX settlement price.

Delivery Commitments. As of February 1, 2012, we had natural gas delivery commitments of 228 Bcf in 2012 and 41 Bcf in 2013 under existing agreements. These commitments require the delivery of natural gas in Arkansas, Pennsylvania and Texas. These amounts are well below our forecasted 2012 and anticipated 2013 production from our available reserves in our Fayetteville Shale, Marcellus Shale and East Texas 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 consumers of natural gas. During the years ended December 31, 2011, 2010 and 2009, no single third-party customer accounted for 10% or more of our consolidated revenues.

Impact of Federal Regulation of Sales of Natural Gas and Oil

Historically, the sale of natural gas in interstate commerce has been regulated pursuant to the Natural Gas Act of 1938, or the NGA, the Natural Gas Policy Act of 1978, or the NGPA, and regulations promulgated thereunder by the Federal Energy Regulatory Commission, or the FERC. In 1989, Congress enacted the Natural Gas Wellhead Decontrol Act, or the Decontrol Act. The Decontrol Act removed all NGA and NGPA price and non-price controls affecting wellhead sales of natural gas effective January 1, 1993 and sales by producers of natural gas can be made at uncontrolled market prices.

The natural gas industry historically has been heavily regulated and from time to time proposals are introduced by Congress and the FERC and judicial decisions are rendered that impact the conduct of business in the natural gas industry.

There can be no assurance that the current, less stringent regulatory approach pursued by the FERC and Congress will continue. We refer you to "Other Items — Environmental Matters" 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 government regulation on our business.

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 play. While improved intrastate and interstate pipeline transportation in Arkansas should increase our access to markets for our natural gas production, these markets will also be 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.

Commencing in 1992, the FERC issued a series of orders (collectively, "Order No. 636"), which require interstate pipelines to provide transportation separately, or "unbundled," from the pipelines' sales of natural gas. Order No. 636 also requires pipelines to provide open-access transportation on a basis that is equal for all shippers. Although Order No. 636 does not directly regulate our activities, the FERC has stated that it intends for Order No. 636 to foster increased competition within all phases of the natural gas industry. Starting in 2000, the FERC issued a series of orders (collectively, "Order No. 637"), which imposed a number of additional reforms designed to enhance competition in natural gas markets. Among other things, Order No. 637 revised the FERC pricing policy by waiving price ceilings for short-term released capacity for a two-year period, and effected changes in FERC regulations relating to scheduling procedures, capacity segmentation, pipeline penalties, rights of first refusal and information reporting. The implementation of these orders has not had a material adverse effect on our results of operations to date.

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 affected as compared to other natural gas producers and marketers by any action taken by the FERC or any other legislative body.

Regulation of Hydraulic Fracturing

We utilize hydraulic fracturing in our E&P operations as a means of maximizing the productivity of our wells. 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 subsurface rock formations. The knowledge and expertise in fracturing techniques we have developed through our operations in the Fayetteville Shale play are being utilized in our other operating areas, currently including our Marcellus Shale acreage and, in the near future, expected to include our exploration programs in New Brunswick, Canada. Successful hydraulic fracturing techniques are also expected to be critical to the development of our recently announced unconventional horizontal oil play targeting the LSBD formation in Arkansas and Louisiana. 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 play, the fracturing fluids we use are comprised of over 99.9% water and sand. The remaining 0.1% is comprised of small quantities of additives which contain chemical compounds such as hydrochloric acid, citric acid, glutaraldehyde and sodium chloride which is used in common household products.

In the past few years, there has been an increased focus on environmental aspects of hydraulic fracturing practices in the United States and Canada. 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.

The Environmental Protection Agency (the "EPA") has asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel under the Safe Drinking Water Act and has begun the process of drafting guidance documents related to this newly asserted regulatory authority. In addition, in July 2011, the EPA issued proposed rules that would subject all oil and gas operations (production, processing, transmission, storage and distribution) to regulation under the New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAPS) programs. The EPA proposed rules also include NSPS standards for completions of hydraulically fractured gas wells. These standards include the reduced emission completion (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 proposed regulations under NESHAPS include maximum achievable control technology (MACT) standards for those glycol dehydrators and storage vessels at major sources of hazardous air pollutants not currently subject to MACT standards. Final action on the proposed rules is expected no later than February 28, 2012. We are currently evaluating the effect these proposed rules could have on our business.

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 (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, with initial results expected to be available by late 2012 and final results by 2014. 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. Also, the U.S. Department of the Interior is considering disclosure requirements or other mandates for hydraulic fracturing on federal lands.

Certain states in which we operate, including Arkansas, Pennsylvania and Texas, 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 the Province of New Brunswick in Canada there are presently no hydraulic fracturing regulations but there has been increased attention on developing a regulatory framework.

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 proposed federal and state legislative and regulatory initiatives relating to hydraulic fracturing that could result in increased costs and additional operating restrictions or delays or prevent us realizing the value of undeveloped acreage" in Item 1A of Part I of this Form 10-K.

Midstream Services

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 our Fayetteville Shale play in Arkansas and our Marcellus Shale play in Pennsylvania.

Our operating income from this segment was $248.0 million on revenues of $2.9 billion in 2011, compared to $191.6 million on revenues of $2.5 billion in 2010 and $122.6 million on revenues of $1.6 billion in 2009. Revenues increased in

2011 and 2010 primarily due to increased gathering revenues and increased volumes marketed. EBITDA generated by our Midstream Services segment was $285.1 million in 2011, compared to $220.5 million in 2010 and $141.9 million in 2009. The increases in 2011 and 2010 operating income and EBITDA were primarily due to increased gathering revenues and marketing margins, partially offset by increased operating costs and expenses. We expect that the operating income and EBITDA of our Midstream Services segment will increase over the next few years as we continue to develop our Fayetteville Shale acreage and Marcellus Shale acreage positions. 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 EBITDA to net income (loss) attributable to Southwestern Energy.

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 play. In 2011, we invested approximately $160.8 million related to these activities and had gathering revenues of $408.2 million, compared to $271.3 million invested and revenues of $316.0 million in 2010 and $214.2 million invested and revenues of $205.6 million in 2009.

DeSoto Gathering is expanding its network of gathering lines and facilities throughout the Fayetteville Shale play area. During 2011, DeSoto Gathering gathered approximately 703.6 Bcf of natural gas volumes in the Fayetteville Shale play area, including 57.4 Bcf of natural gas from third-party operated wells. During 2010, DeSoto Gathering gathered approximately 562.6 Bcf of natural gas volumes in the Fayetteville Shale play area, including 56.6 Bcf of natural gas from third-party wells. In 2009, DeSoto Gathering gathered approximately 367.3 Bcf of natural gas volumes in the Fayetteville Shale play area, including 26.9 Bcf of natural gas from third-party wells. The increase in volumes gathered in over the past three years was primarily due to our growing production volumes from the Fayetteville Shale play. At the end of 2011, DeSoto Gathering had approximately 1,791 miles of pipe from the individual wellheads to the transmission lines and compression equipment representing in aggregate approximately 526,625 horsepower had been installed at 61 central point gathering facilities in the field. Our gathering revenues are expected to grow over the next few years largely as a result of increased development of our acreage in the Fayetteville Shale and the increased development activity undertaken by other operators in the play area.

Angelina Gathering currently engages in gathering activities in East Texas and in Pennsylvania. At year-end 2011, Angelina Gathering had approximately 25 miles of pipe in Texas and 13 miles of pipe in Pennsylvania. At December 31, 2011, compression equipment representing in aggregate approximately 7,100 horsepower had also been installed at one central point gathering facility in Pennsylvania.

Our gathering revenues are expected to grow over the next few years largely as a result of increased development of our acreage in the Fayetteville Shale and Marcellus Shale and the increased development activity undertaken by other operators in those areas.

Gas Marketing

Our gas marketing subsidiary, SES, allows us to capture downstream opportunities related to marketing and transportation of natural gas. SES purchases natural gas production and sells it to end-users and manages the basis and marketing portfolio and acquires transportation rights on third party pipelines and gathering lines. Our current marketing operations primarily relate to the marketing of our own natural gas production and some third-party natural gas. During 2011, we marketed 611.4 Bcf of natural gas, compared to 495.8 Bcf in 2010 and 382.5 Bcf in 2009. Of the total volumes marketed, production from our E&P operated wells accounted for 94% in 2011, compared to 95% in 2010 and 92% in 2009.

SES is a "foundation shipper" on two pipeline projects serving the Fayetteville Shale play growth, the Fayetteville Express Pipeline LLC, or FEP, a 2.0 Bcf per day pipeline that is jointly owned by Kinder Morgan Energy Partners, L.P. and Energy Transfer Partners, L.P., and two pipeline laterals called the Fayetteville and Greenville Laterals, have already been constructed by Texas Gas Transmission, LLC, or Texas Gas, a subsidiary of Boardwalk Pipeline Partners, LP. 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. 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.

Prior to the commencement of service on the Fayetteville and Greenville Laterals and the Fayetteville Express Pipeline, the majority of our natural gas from the Arkoma Basin was moved to markets in the Midwest and was sold primarily based on two indices, "NGPL TexOk" and "Centerpoint East." The Fayetteville and Greenville Laterals and the

Fayetteville Express Pipeline allow us to transport our natural gas to markets in the eastern United States and interconnect with Texas Gas Zone 1, Tennessee Gas Pipeline 100, Trunkline Zone 1A, ANR, Tennessee Gas Pipeline 800, Columbia Gulf Mainline, TETCO M1 30" and Sonat price indices. We rely in part upon the Fayetteville and Greenville Laterals and the Fayetteville Express Pipeline to service our increased production from the Fayetteville Shale play.

During 2011, SES entered into a number of short and long term firm transportation service and gathering 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 and expansions of the system are expected to be in-service by late 2012 and late 2013. In June 2011, SES entered into a long term agreement with Bluestone Gathering, a wholly owned subsidiary of DTE Energy Company, pursuant to which Bluestone Gathering will build and operate a natural gas gathering system in Susquehanna County, Pennsylvania and Broome County, New York, and provide gathering services to SES in support of a portion of our future Marcellus Shale natural gas production. The projected in-service date for the gathering system is expected to be during the third quarter of 2012. We have also entered into a 15-year agreement with a subsidiary of Boardwalk Pipeline Partners for the construction of a gathering system in Susquehanna and Lackawanna counties in Pennsylvania, which once constructed is expected to have a delivery capacity of 175,000 Dekatherm/day. SES also executed firm transportation agreements with Tennessee Gas Pipeline Company ("TGP") that increase our ability to move its Marcellus Shale natural gas production in the short term to market as well as a precedent agreement for an expansion project with a projected in-service date of November 2013 pursuant to which SES has subscribed for 100,000 Dekatherm/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. TGP filed a certificate application for the project with the Federal Energy Regulatory Commission in late 2011. Pending regulatory approvals, construction would begin in 2013, with a projected November 1, 2013 in-service date. 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."

As of December 31, 2011, SES's obligations for demand and similar charges under the firm transportation agreements totaled approximately $2.1 billion and we have not recognized any guarantee obligations with respect to the firm transportation agreements and the gathering project and services.

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

In March 2006, the United States Department of Transportation, or DOT, issued new rules pertaining to certain gathering lines. Compliance with the new rules has not had a material adverse impact on our operations. We refer you to "Other Items — Environmental Matters" 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 government regulation on our Midstream Services business.

In November 2008, the FERC issued a Final Rule in Order No. 720, which requires, in relevant part, major non-interstate natural gas pipelines to post, on a daily basis, specific scheduled flow information at each receipt or delivery point with a design capacity of 15,000 MMBtu per day or more. A "major non-interstate pipeline" is a pipeline that is not classified as a natural gas company under the Natural Gas Act ("NGA") of 1938 and delivers on average more than 50 million MMBtu of natural gas annually over a three year period. Our gathering system in Arkansas constitutes a "major non-interstate pipeline" under Order No. 720. In October 2011, the United States Court of Appeals for the Fifth Circuit issued a decision granting the Texas Pipeline Association and the Railroad Commission's petition for review and vacating FERC's Order Nos. 720 and 720-A. In its order, the 5th Circuit held that Order Nos. 720 and 720-A exceeded the scope of

FERC's authority under the NGA and that the FERC cannot require a non-interstate pipeline to post capacity and scheduling information. Notwithstanding the ruling, Order 720 remains in effect.

Other

Our other operations have primarily consisted of real estate development activities concentrated on tracts of land located in Arkansas. There were no sales of commercial real estate in 2011, 2010 or 2009. As of December 31, 2011, we owned our office complex in Fayetteville, Arkansas, an interest in approximately 15 acres of undeveloped real estate near the Fayetteville complex, our office complex in Conway, Arkansas and 1,761 acres in or near Conway, Arkansas, related to our operations in the Fayetteville Shale play.

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

EBITDA is defined as net income (loss) attributable to Southwestern Energy plus interest, income tax expense, depreciation, depletion and amortization. We have included information concerning 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. EBITDA should not be considered in isolation or as a substitute for net income (loss) attributable to Southwestern Energy, net cash provided by operating activities or other income or cash flow data prepared in accordance with generally accepted accounting principles in the United States, or GAAP, or as a measure of our profitability or liquidity. EBITDA as defined above may not be comparable to similarly titled measures of other companies.

We believe that net income (loss) attributable to Southwestern Energy is the financial measure calculated and presented in accordance with GAAP that is most directly comparable to EBITDA as defined. The following table reconciles EBITDA, as defined, with net income (loss) attributable to Southwestern Energy for the years-ended December 31, 2011, 2010 and 2009:

	E&P	Midstream Services	Other	Total
		(in thousands)		
2011				
Net income (loss) attributable to Southwestern Energy	$ 493,726	$ 142,591	$ 1,452	**$ 637,769**
Depreciation, depletion and amortization	666,125	37,261	1,125	**704,511**
Net interest expense	9,026	15,049	—	**24,075**
Provision for income taxes	322,714	90,221	286	**413,221**
EBITDA	$ 1,491,591	$ 285,122	$ 2,863	**$ 1,779,576**
2010				
Net income attributable to Southwestern Energy	$ 498,346	$ 105,636	$ 136	**$ 604,118**
Depreciation, depletion and amortization	561,018	28,765	549	**590,332**
Net interest expense	7,888	18,275	—	**26,163**
Provision for income taxes	323,748	67,834	77	**391,659**
EBITDA	$ 1,391,000	$ 220,510	$ 762	**$ 1,612,272**
2009				
Net income (loss) attributable to Southwestern Energy	$ (109,690)	$ 73,950	$ 90	**$ (35,650)**
Depreciation, depletion and amortization	474,014	19,213	431	**493,658**
Impairment of natural gas and oil properties	907,812	—	—	**907,812**
Net interest expense	15,237	3,401	—	**18,638**
Provision (benefit) for income taxes	(61,725)	45,303	59	**(16,363)**
EBITDA	$ 1,225,648	$ 141,867	$ 580	**$ 1,368,095**

Environmental Regulation

Our operations are subject to regulation in the jurisdictions in which we operate. We have operations in the United States and, to a much lesser extent, in Canada. In the United States, we are subject to numerous federal, state and local laws and regulations including the Comprehensive Environmental Response, Compensation and Liability Act, or the CERCLA, the Clean Water Act, the Clean Air Act and similar state statutes. These laws and regulations require permits for drilling wells and the maintenance of bonding requirements in order 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, 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.

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. While liability limits apply in some circumstances, a party cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct or resulted from violation of a federal safety, construction or operating regulation. If the party fails to report a spill or to cooperate fully in the cleanup, liability limits likewise do not apply. Few defenses exist to the liability imposed by 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.

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

Our activities in Canada have to date been limited to certain geological and geophysical activities that are not subject to extensive environmental regulation. Once 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.

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, a portion 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 thereon may be subject to CERCLA, the Clean Water Act, the 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.

In the past few years, there has been an increased focus on environmental aspects of hydraulic fracturing practices at the federal, state and local levels of government although hydraulic fracturing is typically regulated by state oil and natural gas commissions. The EPA has asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel under the Safe Drinking Water Act and has begun the process of drafting guidance documents related to this newly asserted regulatory authority. 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. For a discussion of hydraulic fracturing related environmental legislation, we refer you to "Exploration and Production — Federal, State and Local Regulation of Hydraulic Fracturing" and 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 realizing the value of undeveloped acreage" in Item 1A of Part I of this Form 10-K.

Employees

At December 31, 2011, we had 2,287 total employees. None of our employees were covered by a collective bargaining agreement at year-end 2011. We believe that our relationships with our employees are good.

GLOSSARY OF CERTAIN INDUSTRY TERMS

The definitions set forth below shall 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.

"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.

"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 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 herein in reference to crude 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 crude oil to six Mcf of natural gas.

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

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

"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 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 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.

"EBITDA" Represents net income (loss) attributable to Southwestern Energy common stock plus interest, income taxes, depreciation, depletion and amortization and the impairment of natural gas and oil properties. 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 EBITDA with our net income (loss) attributable to Southwestern Energy from our audited financial statements.

"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 crude oil or other liquid hydrocarbons.

"Mcf" One thousand cubic feet of natural gas.

"Mcfe" One thousand cubic feet of natural gas equivalent. Determined using the ratio of one barrel of crude oil to six Mcf of natural gas.

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

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

"MMcf" One million cubic feet of natural gas.

"MMcfe" One million cubic feet of natural gas equivalent. Determined using the ratio of one barrel of crude 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 acre" Deemed to exist when the sum of fractional ownership working interests in gross wells or acres equals one. The number of net wells or acres is the sum of the fractional working interests owned in gross wells or acres expressed as whole numbers and fractions of whole numbers. 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.

"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 from the investment.

"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. Determined using the ratio of one barrel of crude oil to six Mcf of natural gas.

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

"Undeveloped acreage" Those leased acres on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil or gas regardless of whether such acreage contains proved reserves. 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 gas reserves" Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Also referred to as "undeveloped reserves." 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 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 crude oil 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."

A substantial or extended decline in natural gas and oil prices would have a material adverse affect on us.

In the first half of 2008, natural gas and oil prices were at or near their highest historical levels but subsequently natural gas and oil prices declined significantly. Natural gas prices declined in 2011 as compared with 2010 and have continued to decline in the first two months of 2012, and are not expected to significantly increase in 2012. The further significant decline in natural gas and oil prices 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 may be economically produced by us. A significant decrease in price levels for an extended period would negatively affect us in several ways including:

- our cash flow would be reduced, decreasing funds available for capital investments employed to replace reserves or increase production;
- certain reserves would no longer be economic to produce, leading to both lower proved reserves and cash flow; and
- access to other sources of capital, such as equity or long-term debt markets, could be severely limited or unavailable.

Consequently, our revenues and profitability would suffer.

Lower natural gas and oil prices and/or increased development costs may cause us to record ceiling test write-downs.

We use the full cost method of accounting for our natural gas and oil operations. Accordingly, we capitalize the cost to acquire, explore for and develop natural gas and oil properties. Under the full cost accounting rules of the SEC, the capitalized costs of natural gas and oil properties – net of accumulated depreciation, depletion and amortization, and deferred income taxes – may not exceed a "ceiling limit" on a country-by-country basis. This is equal to the present value of estimated future net cash flows from proved natural gas and oil reserves, discounted at 10 percent, plus the lower of cost or fair value of unproved properties included in the costs being amortized, net of related tax effects.

These rules generally require pricing future natural gas and oil production at the unescalated natural gas and oil prices in effect at the end of each fiscal quarter, including the impact of derivatives qualifying as cash flow hedges, utilizing the average price in the 12-month period prior to the end of each fiscal quarter, defined as the unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices were defined by contractual arrangements, excluding escalations based upon future conditions. They also require a write-down if the ceiling limit is exceeded. Once a write-down is taken, it cannot be reversed in future periods even if natural gas and oil prices increase.

In the period ended March 31, 2009, we incurred a ceiling test write-down of $907.8 million which resulted in an operating loss for our company for 2009. If natural gas and oil prices decline below levels utilized in our ceiling limit test at December 31, 2011 and/or operating costs, development costs, transportation costs or basis differentials increase, a write-down may occur, which would adversely impact our results of operation and financial condition. Using the first-day-of-the-month prices of natural gas for the first two months of 2012 and NYMEX strip prices for the remainder of 2012, as applicable, the prices required to be used to determine the ceiling limit could result in a ceiling test write-down in the first quarter of 2012 and are likely to require ceiling test write-downs in each of the remaining quarters in 2012.

Our level of indebtedness and the terms of our financing arrangements may adversely affect operations and limit our growth.

At December 31, 2011, we had total indebtedness of $1,343.3 million, including borrowings of $671.5 million under our revolving credit facility. At February 23, 2012, we had long-term indebtedness of $1,495.2 million, including borrowings of $823.4 million under our revolving credit facility. We currently expect to utilize the borrowing availability under our revolving credit facility in order to fund a portion of our capital investments in 2012. See also our risk factor headed "We may have difficulty financing our planned capital investments which could adversely affect our growth," below.

The terms of our various financing agreements, including but not limited to the indentures relating to our outstanding senior notes, our revolving credit facility and the master lease agreement relating to our drilling rigs and our other equipment leases, which we collectively refer to as our "financing agreements," impose restrictions on our ability and, in some cases, the ability of our subsidiaries to take a number of actions that we may otherwise desire to take, including one or more of the following:

- incurring additional debt, including guarantees of indebtedness;
- creating liens on our assets; and
- selling all or substantially all of our assets.

Our level of indebtedness and off-balance sheet obligations, and the covenants contained in our financing agreements, could have important consequences for our operations, including:

- requiring us to dedicate a substantial portion of our cash flow from operations to required payments, thereby reducing the availability of cash flow for working capital, capital investments and other general business activities;
- limiting our ability to obtain additional financing in the future for working capital, capital investments, acquisitions and general corporate and other activities;
- limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate; and
- detracting from our ability to successfully withstand a downturn in our business or the economy generally.

Our ability to comply with the covenants and other restrictions in our financing agreements may be affected by events beyond our control, including prevailing economic and financial conditions. If we fail to comply with the covenants and other restrictions, it could lead to an event of default and the acceleration of our obligations under those agreements. We may not have sufficient funds to make such payments. If we are unable to satisfy our obligations with cash on hand, we could attempt to refinance such debt, sell assets or repay such debt with the proceeds from a public offering of securities. We cannot assure you that we will be able to generate sufficient cash flow to pay the interest on our debt, to meet our lease obligations, or that future borrowings, equity financings or proceeds from the sale of assets will be available to pay or refinance such debt or obligations. The terms of our financing agreements may also prohibit us from taking such actions. Factors that will affect our ability to raise cash through a public offering, a refinancing of our debt or a sale of assets include financial market conditions and our market value and operating performance at the time of such offering or other financing. We cannot assure you that any such proposed offering, refinancing or sale of assets can be successfully completed or, if completed, that the terms will be favorable to us.

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 as a result of our drilling program. Our planned capital investments for 2012 are expected to exceed the net cash generated by our operations under current natural gas prices. We expect to borrow under our credit facility to fund capital investments that are in excess of our net cash flow and cash on hand. Our ability to borrow under our credit facility is subject to certain conditions. At December 31, 2011, we were in compliance with the borrowing conditions of our credit facility. If we are not in compliance with the terms of our credit facility in the future or if the lenders under our credit facility are unable to fulfill their commitments, we may not be able to borrow under the facility to fund our capital investments. We also cannot be certain that other financing will be available to us on acceptable terms or at all. In the event additional capital resources are unavailable, we may curtail our drilling, development and other activities or be forced to sell some of our assets on an untimely or unfavorable basis. Any such curtailment or sale could have a material adverse effect on our results and future operations.

Natural gas and oil prices are volatile. Volatility in natural gas and oil prices can adversely affect our results and the price of our common stock. This volatility also makes valuation of natural gas and oil producing properties difficult and can disrupt markets.

Natural gas and oil prices have historically been, and are likely to continue to be, volatile. In recent years, there has been a significant decline in natural gas prices as evidenced by New York Mercantile Exchange ("NYMEX") natural gas prices ranging from a high of $13.58 per MMBtu in 2008 to a recent low of $2.32 per MMBtu in January 2012. The prices for natural gas and oil are subject to wide fluctuation in response to a number of factors, including:

- relatively minor changes in the supply of and demand for natural gas and oil;
- market uncertainty;
- worldwide economic conditions;
- weather conditions;
- import prices;
- political conditions in major oil producing regions, especially the Middle East;
- actions taken by OPEC;
- competition from other sources of energy; and
- economic, political and regulatory developments.

Historically we have also experienced price volatility as a result of locational differentials for our production from the Arkoma Basin and East Texas, which at any time may further widen due to pipeline or other constraints. Price volatility makes it difficult to project the return on exploration and development projects involving our natural gas and oil properties and to estimate with precision the value of producing properties that we may own or propose to acquire. In addition, unusually volatile prices often disrupt the market for natural gas and oil properties, as buyers and sellers have more difficulty agreeing on the purchase price of properties. Our results of operations may fluctuate significantly as a result of, among other things, variations in natural gas and oil prices and production performance. In recent years, natural gas and oil price volatility has become increasingly severe.

The recent adoption of financial reform legislation could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business which could have a material adverse effect on our financial position, results of operations and cash flows.

In July 2010, the Dodd-Frank Wall Street Reform and Consumer Protection Act was passed by Congress and subsequently signed into law. The new legislation required the Commodities Futures Trading Commission (the "CFTC") and the SEC to promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment. The CFTC has proposed regulations to set position limits for certain futures and option contracts in the major energy markets. The financial reform legislation may also require us to comply with margin requirements and with certain clearing and trade execution requirements in connection with our derivative activities. At this time it is not possible to predict whether or when the CFTC will adopt those rules or include comparable provisions in its rulemaking under the new legislation or how those rules will apply to us. The financial reform legislation may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties, and such developments may affect the business relationships we have with those counterparties. The new legislation and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks, reduce our ability to monetize or restructure our existing derivative contracts, increase our exposure to less creditworthy counterparties and limit our access to the capital necessary to grow our business. If, as a result of the legislation and regulations, we are no longer able to use derivatives as we have in the past, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital investments. Our revenues could also be adversely affected if a consequence of the legislation and regulations is lower commodity prices. Any of these consequences could have a material adverse effect on our financial position, results of operations and cash flows.

Working interest owners of some of our properties may be unwilling or unable to cover their portion of development costs, which could change our exploration and development plans.

Some of our working interest owners may have difficulties obtaining the capital needed to finance their activities, or may believe that estimated drilling and completion costs are excessive. As a result, these working interest owners may choose not to participate in certain wells or be unable or unwilling to pay their share of well costs as they become due. These actions could cause us to change our development plans for the affected properties.

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

Our reserve data represents the estimates of our reservoir engineers made under the supervision of our management. Our reserve estimates are audited each year by Netherland, Sewell & Associates, Inc., or NSAI, an independent petroleum engineering firm. 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 90% of 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 90% present value as of December 31, 2011 accounted for approximately 92% of our total proved reserves and approximately 98% 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. For the year-ended December 31, 2011, on January 30, 2012, NSAI issued its audit opinion as to the reasonableness of our reserve estimates, stating that our estimated proved oil and 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.

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 over eight years of experience in petroleum engineering, including the estimation of oil and natural gas reserves. He reports to our Senior Vice President – Corporate Development, who has more than 30 years of experience in reservoir engineering, including the estimation of oil and gas reserves in multiple basins both in the United States and internationally. On our behalf, the Senior 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 Senior 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 and final authority over the estimates of our proved reserves rests with our Board of Directors. We incorporate many factors and assumptions into our estimates including:

- expected reservoir characteristics based on geological, geophysical and engineering assessments;
- future production rates based on historical performance and expected future operating and investment activities;
- future oil and natural gas prices and quality and locational differentials; and
- future development and operating costs.

Although we believe our assumptions are reasonable based on the information available to us at the time we prepare our estimates, our actual reserves could vary considerably from estimated quantities of proved natural gas and oil reserves (in the aggregate and for a particular geographic location), production, revenues, taxes and development and operating expenditures. In addition, our estimates of reserves may be subject to downward or upward revision based upon production history, results of future exploration and development, prevailing natural gas and oil prices, severance taxes, operating and development costs and other factors. In 2011, our reserves were revised upward by 33.7 Bcfe, primarily due to improved performance in our Marcellus Shale properties, partially offset by downward performance revisions in our East Texas, Arkoma and Fayetteville properties and downward price revisions due to a comparative price decrease in the average 2011 price from the average 2010 price. In 2010, our reserves were revised upward by 309.6 Bcfe, primarily due to improved performance in our Fayetteville Shale properties and upward price revisions due to a comparative price increase in the average 2010 price from the average 2009 price, partially offset by downward performance revisions in our East Texas properties. In 2009, our reserves were revised upward by 92.9 Bcfe, primarily due to improved performance in our Fayetteville Shale properties, partially offset by downward revisions due to a comparative decrease in the average 2009 price from the year-end 2008 gas price. These revisions represented no greater than 7% of our total reserve estimates in each of these years, which we believe is indicative of the effectiveness of our internal controls. Because we review our reserve projections for every property at the end of every year, any material change in a reserve estimate is included in subsequent reserve reports.

Finally, recovery of undeveloped reserves generally requires significant capital investments and successful drilling operations. At December 31, 2011, approximately 2,633 Bcfe of our estimated proved reserves were undeveloped. Our reserve data assume that we can and will make these expenditures and conduct these operations successfully, which may not occur. Please read "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 additional information regarding the uncertainty of reserve estimates.

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 drilling plans for the Fayetteville Shale play and Marcellus Shale play are subject to change.

As of December 31, 2011, we had drilled and completed 2,380 operated wells relating to our Fayetteville Shale play and 23 operated wells relating to our Marcellus Shale play. At year-end 2011, approximately 74% of our leasehold acreage in the Fayetteville Shale was held by production, excluding our acreage in the traditional Fairway and the approximately 163,000 net federal acres we hold in the Ozark Highlands Unit. Approximately 3% of our leasehold acreage in the Marcellus Shale was held by production at year-end 2011. 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 regional basis 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 oil field 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 operate our own drillings rigs;
- availability and cost of capital; or
- the impact of federal, state and local government regulation, including any increase in severance taxes.

We continue to gather data about our prospects in our operating areas, and 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.

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.

Leases on approximately 235,167 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, of which 184,696 net acres are held on federal lands. Approximately 112,832 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 play and Marcellus Shale play 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.

If our Fayetteville Shale and Marcellus Shale drilling programs fail to produce our projected supply of natural gas, our investments in our gas 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.

Through December 31, 2011, we had invested approximately $933.0 million in our gas gathering system built for the Fayetteville Shale play and approximately $30.7 million in our gas gathering system built for the Marcellus Shale play. To the extent necessary to gather our production, we may make further substantial investments in the expansion of our gas gathering systems. Our gas gathering business will largely rely on natural gas sourced from our operations. Our marketing subsidiary has also entered into multiple firm transportation agreements relating to natural gas volumes produced from our Fayetteville Shale play as well as a number of firm transportation and gathering agreements relating to the Marcellus Shale play. As of December 31, 2011, our aggregate demand charge commitments under these firm transportation agreements and gathering agreements were approximately $2.1 billion. If our Fayetteville Shale and Marcellus Shale drilling programs fail to produce significant supplies of natural gas, 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. These events could have an adverse effect on our results of operations, financial condition and cash flows.

Our exploration, development and drilling efforts and our operation of our wells may not be profitable or achieve our targeted returns.

Exploration, development, drilling and production activities are subject to many risks, including the risk that no commercially productive reservoirs will be discovered. We invest in property, including undeveloped leasehold acreage that we believe will result in projects that will add value over time. However, we cannot assure you that all prospects will result in viable projects or that we will not abandon our initial investments. Additionally, there can be no assurance that leasehold acreage acquired by us will be profitably developed, that new wells drilled by us in prospects that we pursue will be productive or that we will recover all or any portion of our investment in such leasehold acreage or wells. Drilling for natural gas and oil may involve unprofitable efforts, not only from dry wells but also from wells that are productive but do not produce sufficient net reserves to return a profit after deducting drilling, operating and other costs. In addition, wells that are profitable may not achieve our targeted rate of return. Our ability to achieve our target PVI results is dependent upon the current and future market prices for natural gas and crude oil, costs associated with producing natural gas and crude oil and our ability to add reserves at an acceptable cost. We rely to a significant extent on seismic data and other advanced technologies in identifying leasehold acreage prospects and in conducting our exploration activities. The seismic data and other technologies we use do not allow us to know conclusively prior to acquisition of leasehold acreage or drilling a well whether natural gas or oil is present or may be produced economically. The use of seismic data and other technologies also requires greater pre-drilling expenditures than traditional drilling strategies.

In addition, we may not be successful in implementing our business strategy of controlling and reducing our drilling and production costs in order to improve our overall return. The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a project. Further, our drilling operations may be curtailed, delayed or canceled as a result of numerous factors, including unexpected drilling conditions, title problems, pressure or irregularities in formations, equipment failures or accidents, adverse weather conditions, environmental and other governmental requirements and the cost of, or shortages or delays in the availability of, drilling rigs, equipment and services.

The success of our New Venture 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.

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

We may inject water into formations on some of our properties to increase the production of crude oil, natural gas and associated liquids or employ other enhanced recovery methods in our operations. The additional production and reserves, if any, attributable to the use of enhanced recovery methods are inherently difficult to predict. If our enhanced recovery methods do not allow for the extraction of crude oil, natural gas and associated liquids in a manner or to the extent that we anticipate, we may not realize an acceptable return on our investments in such projects. In addition, if proposed legislation and regulatory initiatives relating to hydraulic fracturing become law, the cost of some of these enhanced recovery methods could increase substantially.

Ultimately, the success of drilling and completion techniques and enhanced recovery methods can only be evaluated over time as more wells are drilled and production profiles are established over a sufficiently long time period. If our drilling results are less than anticipated or we are unable to execute our drilling program because of capital constraints, lease expirations, limited access to gathering systems and takeaway capacity, and/or crude oil, natural gas and natural gas liquids prices decline, the return on our investment for a particular project may not be as attractive as we anticipated and the value of our undeveloped acreage could decline in the future.

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 realizing the value of undeveloped acreage.

We utilize hydraulic fracturing in our E&P operations as a means of maximizing the productivity of our wells. 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 subsurface rock formations. The knowledge and expertise in fracturing techniques we have developed through our operations in the Fayetteville Shale play are being utilized in our other operating areas, currently including our Marcellus Shale acreage and in the future expected to also include our exploration program in New Brunswick, Canada. Successful hydraulic fracturing techniques are also expected to be critical to the development of our recently announced unconventional horizontal oil play targeting the LSBD formation in Arkansas and Louisiana. 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 play, the fracturing fluids we use are comprised of over 99.9% water and sand. The remaining 0.1% is comprised of small quantities of additives that contain chemical compounds such as hydrochloric acid, citric acid, glutaraldehyde and sodium chloride which is used in common household products.

In the past few years, there has been an increased focus on environmental aspects of hydraulic fracturing practices in the United States and Canada. In the United States, hydraulic fracturing is typically regulated by state oil and natural gas commissions but there has recently been a number of regulatory initiatives at the federal and local levels as well as by other state agencies. The Environmental Protection Agency (the “EPA”) has asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel under the Safe Drinking Water Act and has begun the process of drafting guidance documents related to this newly asserted regulatory authority.

In July 2011, the EPA issued proposed rules that would subject all oil and gas operations (production, processing, transmission, storage and distribution) to regulation under the New Source Performance Standards (NSPS) and National

Emission Standards for Hazardous Air Pollutants (NESHAPS) programs. The EPA proposed rules also include NSPS standards for completions of hydraulically fractured gas wells. These standards include the reduced emission completion (REC) techniques developed in the EPA's Natural Gas STAR program along with the pit flaring of gas not sent to the gathering line. The standards would be applicable to newly drilled and fractured wells as well as existing wells that are refractured. Further, the proposed regulations under NESHAPS include maximum achievable control technology (MACT) standards for those glycol dehydrators and storage vessels at major sources of hazardous air pollutants not currently subject to MACT standards. Final action on the proposed rules is expected no later than February 28, 2012. We are currently evaluating the effect these proposed rules could have on our business.

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 (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, with initial results expected to be available by late 2012 and final results by 2014. 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. Also, the U.S. Department of the Interior is considering disclosure requirements or other mandates for hydraulic fracturing on federal lands.

Certain states in which we operate, including Arkansas, Pennsylvania and Texas, 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 the Province of New Brunswick in Canada, there are presently no hydraulic fracturing regulations but there has been increased attention on developing a regulatory framework.

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 incur substantial costs to comply with government regulations, especially regulations relating to environmental protection, and could incur even greater costs in the future.

Our exploration, production, development and gas gathering and marketing operations are regulated extensively at the federal, state and local levels. We have made and will continue to make large expenditures in our efforts to comply with these regulations, including environmental regulation. The natural gas and oil regulatory environment could change in ways that might substantially increase these costs. Hydrocarbon-producing states regulate conservation practices and the protection of correlative rights. These regulations affect our operations and limit the quantity of hydrocarbons we may produce and sell. In addition, at the U.S. federal level, the FERC regulates interstate transportation of natural gas under the NGA. Other regulated matters include marketing, pricing, transportation and valuation of royalty payments.

As an owner or lessee and operator of natural gas and oil properties, and an owner of gas gathering systems and sand mine, we are subject to various federal, state and local regulations relating to discharge of materials into, and protection of, the environment. These regulations may, among other things, impose liability on us for the cost of pollution clean-up resulting from operations, subject us to liability for pollution damages, and require suspension or cessation of operations in affected areas. Changes in or additions to regulations regarding the protection of the environment could significantly increase our costs of compliance, or otherwise adversely affect our business.

One of the responsibilities of owning and operating natural gas and oil properties is paying for the cost of abandonment. We may incur significant abandonment costs in the future which could adversely affect our financial results.

Natural gas and oil drilling and producing operations involve various operating and environmental risks that could result in substantial losses.

Our operations are subject to all the risks normally incident to the operation and development of natural gas and oil properties, the drilling of natural gas and oil wells and the sale of natural gas and oil, including but not limited to encountering well blowouts, cratering and explosions, pipe failure, fires, formations with abnormal pressures, uncontrollable flows of oil, natural gas, brine or well fluids, hydrocarbon drainage from adjacent third-party production, release of contaminants into the environment and other environmental hazards and risks and failure of counterparties to perform as agreed.

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. However, our insurance does not protect us against all operational risks. For example, we generally do not maintain business interruption insurance. Additionally, 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 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 the shutting-in of producing wells, the delay or discontinuance of development plans for our properties, or lower price realizations. 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, if drilling in the Marcellus Shale continues to be successful, the amount of natural gas being produced by us and others could exceed the capacity of, and result in strains on, the various gathering, and transportation systems, pipelines, and other infrastructure available in these areas. It will be necessary for additional infrastructure, pipelines, gathering, and transportation systems and processing facilities to be expanded, built or developed to accommodate anticipated production from these areas. Because of the current economic climate, certain processing or pipeline and other gathering or transportation projects that might be, or are being, considered for these areas may not be developed timely or at all due to lack of financing, construction and permitting delays, permitting costs, well fees proposed in Pennsylvania, or other constraints. In addition, capital and other constraints could limit our ability to build or access intrastate gathering and transportation systems necessary to transport our production to interstate pipelines or other points of sale or delivery. In such event, we might have to delay or discontinue development activities or shut in our wells to wait for sufficient infrastructure development or capacity expansion and/or sell production at significantly lower prices than those quoted on NYMEX, which would adversely affect our results of operations and cash flows.

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, accidents, loss of pipeline, gathering, processing or transportation system access or capacity, field labor issues or strikes, or we might voluntarily curtail production in response to market conditions. If a substantial amount of our production is interrupted at the same time, it could temporarily adversely affect our cash flows and results of operations.

Shortages of oilfield equipment, services, supplies, raw materials and qualified personnel could adversely affect our results of operations.

The demand for qualified and experienced field personnel to drill wells and conduct field operations, 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 prices for 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 price 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 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, concessions, marketing agreements, equipment and labor against companies with financial and other resources substantially larger than 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.

We have made significant investments in our oilfield service operations, including our drilling rig and sand mine operations in order to meet certain of our oilfield service and resource needs, lower our costs and increase of the efficiency of our operations. If our exploration and production activities are curtailed or disrupted, these operations may adversely impact our results of operations. In addition, our continued expansion of these operations may adversely impact our relationships with third-party providers.

We have made significant investments in order to meet certain of our oilfield services needs, including establishing our own drilling rig operations and sand mine. In 2012, we plan to invest in and commence providing pressure pumping services for a portion of our operated wells. We may make additional investments to expand these operations in the future. Our drilling operations are conducted through our subsidiary, DDI, which had 404 employees as of December 31, 2011. We have lease commitments for 14 drilling rigs and related equipment with respect to DDI's operations and we also own one drilling rig. In addition to these rigs, we have contracts with third-party drilling companies for use of their rigs which may not be terminable without penalty. In 2010, another of our subsidiaries, DeSoto Sand, LLC, began operating our first sand mine in Arkansas in order to meet a portion of our sand needs for the Fayetteville Shale play. We also purchase sand for use in our operations from various third parties, including certain of our oilfield service providers. Our drilling rig and sand mine operations 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. We may also compete with third-party providers for qualified personnel, which could adversely affect our relationships with such providers. If the operations of our drilling rigs and/or sand mine are disrupted or our existing third-party providers discontinue their relationships with us, we may not be able to secure alternative services or resources on a timely basis, or at all. Even if we are able to secure alternative services or resources, there can be no assurance that such services or resources will be of equivalent quality or that pricing and other terms will be favorable to us. If we are unable to secure third-party services or resources or if the terms are not favorable to us, our financial condition and results of operations could be adversely affected.

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.

If natural gas prices decline further, our failure to hedge the remaining portion of our expected 2012 production could adversely affect our results of operations and financial condition.

To reduce our exposure to fluctuations in the prices of natural gas and oil, historically, we have entered into hedging arrangements with respect to a significant portion of our expected production. As of February 23, 2012, we had NYMEX commodity price hedges on approximately 47% of our targeted 2012 natural gas production as compared to approximately 45% for 2009, 30% for 2010 and 52% for 2011. Our price risk management activities increased natural gas sales by $315.6 million in 2011, increased natural gas sales by $290.3 million in 2010 and increased natural gas sales by $587.8 million in 2009. If natural gas prices decline in 2012, unless we enter into additional hedging arrangements, our revenues would be adversely affected. To the extent that we engage in additional hedging activities in the current price environment, we would not realize the benefit of price increases above the levels of the hedges.

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

- our production is less than expected;
- there is a widening of price differentials between delivery points for our production and the delivery point assumed in the hedge arrangement;
- the counterparties to our futures contracts fail to perform the contracts; or
- a sudden, unexpected event materially impacts natural gas or oil prices.

Finally, future market price volatility could create significant changes to the hedge positions recorded on 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.

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:

- the repeal of the percentage depletion allowance for oil and natural gas properties;
- the elimination of current deductions for intangible drilling and development costs;
- the elimination of the deduction for certain domestic production activities; and
- an 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.

Our ability to produce natural gas 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, particularly with respect to our Fayetteville Shale and Marcellus Shale operations, and also possibly our recently announced unconventional oil play targeting the LSBD formation in Arkansas and Louisiana. 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. 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 Environmental Protection Agency, or 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. The EPA has also adopted regulations requiring certain natural gas and oil exploration and production facilities to obtain permits for storm water discharges. 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 affect on our operations and financial condition.

Climate change and global warming concerns could lead to additional regulatory measures that may adversely impact our operations and financial condition.

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 carbon dioxide, or CO2, 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 CO2 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.

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 us, gain control of the company, or replace 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.

ITEM 1B. UNRESOLVED STAFF COMMENTS.

None.

ITEM 2. PROPERTIES

The summary of our oil and natural gas reserves as of fiscal year-end 2011 based on average fiscal-year prices, as required by Item 1202 of Regulation S-K, is included in the table headed "2011 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 was the technical person primarily responsible for overseeing the preparation of our reserves estimates, who reports to the Senior Vice President – Corporate Development. Our Manager – Capital Budgeting & Reserves has more than eight years of experience in petroleum engineering, including the estimation of oil and natural gas reserves and holds a Bachelor of Science in Chemical Engineering and a Masters in Business Administration. Prior to joining us in 2007, our Manager – Capital Budgeting & Reserves served in various reservoir engineering roles for Exxon-Mobil Corporation and is a member of the Society of Petroleum Engineers. Our Senior Vice President – Corporate Development has more than 30 years of experience in reservoir engineering including the estimation of oil and gas reserves in multiple basins both in the United States and internationally. Prior to joining Southwestern in 2008, our Senior Vice President – Corporate Development served in various engineering and senior management roles for Tenneco Oil Company, Enron Oil & Gas Company ("EOG Resources"), 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 Senior Vice President – Corporate Development engages Netherland, Sewell & Associates, Inc., or 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 25 years and over 10 years of practical experience in petroleum geosciences and petroleum engineering, respectively; (2) have over 21 years and over 10 years of experience in the estimation and evaluation of reserves, respectively; (3) each have college degrees; (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 and final authority over the estimates of our proved reserves rests with our Board of Directors. 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, 2011:

	Undeveloped		Developed	
	Gross	Net	Gross	Net
Fayetteville Shale Play(1)	554,240	360,473	743,680	440,313
Marcellus Shale Play(2)	197,743	180,676	6,254	6,217
Ark-La-Tex:				
Conventional Arkoma(3)	234,062	138,191	255,123	181,359
East Texas(4)	37,628	27,281	91,844	63,801
New Ventures:				
USA New Ventures – LSBD(5)	750,000	520,619	—	—
USA New Ventures – Other(6)	730,875	561,177	—	—
Canada New Ventures(7)	2,518,518	2,518,518	—	—
	5,023,066	4,306,935	1,096,901	691,690

(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 2,804 net acres in 2012, 208,563 net acres in 2013, which includes 184,696 net acres held on federal lands, and 23,800 net acres in 2014.

(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 58,210 net acres in 2012, 44,551 net acres in 2013 and 10,071 net acres in 2014.

(3) Includes 123,442 net developed acres and 1,614 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 30,025 net acres in 2012, 2,181 net acres in 2013 and 31,769 net acres in 2014.

(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 380 net acres in 2012, 790 net acres in 2013 and 77 net acres in 2014.

(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 15,860 net acres in 2012, 64,120 net acres in 2013 and 228,660 net acres in 2014.

(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 1,200 net acres in 2012, 1,200 net acres in 2013 and 31,600 net acres in 2014.

(7) Assuming the options are not extended/exercised by March 2013 then, in such event, 2,518,518 net acres will expire in 2013.

Producing wells as of December 31, 2011(1):

	Natural Gas		Oil		Total		Gross Wells
	Gross	Net	Gross	Net	Gross	Net	Operated
Fayetteville Shale Play	2,735	1,856	—	—	2,735	1,856	2,283
Marcellus Shale Play	30	22	—	—	30	22	23
Ark-La-Tex:							
Conventional Arkoma	1,185	574	—	—	1,185	574	554
East Texas	591	452	11	7	602	459	536
	4,541	2,904	11	7	4,552	2,911	3,396

(1) As of December 31, 2011, there were no producing wells in New Ventures.

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
2011	1.0	0.6	0.0	0.0	1.0	0.6
2010	0.0	0.0	0.0	0.0	0.0	0.0
2009	1.0	0.9	2.0	1.2	3.0	2.1

Development[1]

	Productive Wells		Dry Wells		Total	
Year	Gross	Net	Gross	Net	Gross	Net
2011	446.0	307.7	0.0	0.0	446.0	307.7
2010[2]	483.0	305.5	3.0	1.9	486.0	307.4
2009	418.0	253.6	3.0	1.8	421.0	255.4

(1) We have not drilled any exploratory or development wells in Canada in the past three years.
(2) 2010 dry wells include 2 gross wells (1.6 net wells) in the Fayetteville Shale play that were plugged and abandoned due to mechanical issues encountered during drilling.

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, 2011 [1]

	Gross	Net
Drilling:		
Exploratory	1.0	1.0
Development	108.0	75.0
Total	109.0	76.0
Completing:		
Exploratory	2.0	1.0
Development	150.0	107.4
Total	152.0	108.4
Drilling & Completing:		
Exploratory	3.0	2.0
Development	258.0	182.4
Total	261.0	184.4

(1) As of December 31, 2011, 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 December31,		
	2011	2010	2009
Natural Gas			
Production (Bcf):			
Fayetteville Shale	**436.8**	350.2	243.5
Total	**499.4**	403.6	299.7
Average gas price per Mcf, including hedges:			
Fayetteville Shale	**$4.23**	$4.73	$5.73
Total	**$4.19**	$4.64	$5.30
Average gas price per Mcf, excluding hedges:			
Fayetteville Shale	**$3.52**	$3.89	$3.31
Total	**$3.56**	$3.93	$3.34
Oil			
Oil production (MBbls)(1)	**97**	171	124
Average oil price per Bbl(1)	**$94.08**	$76.84	$54.99
Average Production Cost			
Cost per Mcfe, excluding ad valorem and severance taxes:			
Fayetteville Shale	**$0.88**	$0.86	$0.80
Total	**$0.84**	$0.83	$0.77

(1) Our Fayetteville Shale operations did not produce any oil for the years ended December 31, 2011, 2010 and 2009.

During 2011, 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

At December 31, 2011, our Midstream Services segment had 1,791 miles, 25 miles and 13 miles of pipe in its gathering systems located in Arkansas, Texas, and Pennsylvania, 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 natural 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 endeavor to conduct a thorough title examination and perform curative work with respect to significant defects before proceeding with operations. We believe that we have performed a thorough 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.

In February 2009, SEPCO was added as a defendant in a Third Amended Petition in the matter of Tovah Energy, LLC and Toby Berry-Helfand v. David Michael Grimes, et, al. In the Sixth Amended Petition, filed in July 2010, in the 273rd District Court in Shelby County, Texas (collectively, the “Sixth Petition”), plaintiff alleged that, in 2005, they 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, the plaintiff’s allegations in the Sixth Petition included 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 15, 2005 and February 15, 2006. In the Sixth Petition, plaintiff sought actual damages of over $55 million as well as other remedies, including special damages and punitive damages of four times the amount of actual damages established at trial.

Immediately before the commencement of the trial in November 2010, plaintiff was permitted, over SEPCO’s objections, to file a Seventh Amended Petition claiming actual damages of $46 million and also seeking the equitable remedy of disgorgement of all profits for the misappropriation of trade secrets and the breach of fiduciary duty claims. In December 2010, the jury found in favor of the plaintiff with respect to all of the statutory and common law claims and awarded $11.4 million in compensatory damages. The jury did not, however, award the plaintiff any special, punitive or other damages. In addition, the jury separately determined that SEPCO’s profits for purposes of disgorgement were $381.5 million. This profit determination does not constitute a judgment or an award. The plaintiff’s entitlement to disgorgement of profits as an equitable remedy will be determined by the judge and it is within the judge’s discretion to award none, some or all the amount of profit to the plaintiff. On December 31, 2010, the plaintiff filed a motion to enter the judgment based on the jury’s verdict. On February 11, 2011, SEPCO filed a motion for a judgment notwithstanding the verdict and a motion to disregard certain findings. On March 11, 2011, the plaintiff filed an amended motion for judgment and intervenor filed its motion for judgment seeking not only the monetary damages and the profits determined by the jury but also seeking, as a new remedy, a constructive trust for profits from 143 wells as well as future drilling and sales of properties in the prospect areas. A hearing on the post-verdict motions was held on March 14, 2011. At the suggestion of the judge, all parties voluntarily agreed to participate in non-binding mediation efforts. The mediation occurred on April 6, 2011 and was unsuccessful. On June 6, 2011, SEPCO received by mail a letter dated June 2, 2011 from the judge, in which he made certain rulings with respect to the post-verdict motions and responses filed by the parties. In his rulings, the judge denied SEPCO’s motion for judgment, judgment notwithstanding the verdict and to disregard certain findings. Plaintiff’s and intervenor’s claim for a constructive trust was denied but the judge ruled that plaintiff and intervenor shall recover from SEPCO $11.4 million and a reasonable attorney’s fee of 40% of the total damages awarded and are entitled to recover on their claim for disgorgement. The judge instructed that SEPCO calculate the profit on the designated wells for each respective period. SEPCO performed the calculation and provided it to the judge in June 2011. On July 5, 2011, plaintiff and intervenor filed a letter with the court raising objections to the accounting provided by SEPCO, to which SEPCO filed a response on July 11, 2011. On July 12, 2011, the judge sent a letter to the parties in which he ruled that after reviewing the parties’ respective position letters, he was awarding $23.9 million in disgorgement damages in favor of the plaintiff and intervenor. In the July 12, 2011 letter, the judge instructed the plaintiff and intervenor to prepare a judgment for his approval prior to July 21, 2011 consistent with his findings in his June 2, 2011 letter and the disgorgement award. On August 24, 2011, a judgment was entered pursuant to which plaintiff and intervenor are 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. On September 22, 2011, the plaintiff and intervenor filed a motion to modify, correct or reform the judgment which requested that the court vacate the final judgment ordering SEPCO to produce additional accounting information and reconsider the amount SEPCO should disgorge. On September 23, 2011, SEPCO filed a motion for a new trial and on November 18, 2011 filed a notice of appeal. On November 30, 2011, the court approved SEPCO’s supersedeas bond in the amount of $14.1 million, which stays execution on the judgment pending appeal. The bond covers the $11.4 million judgment for actual damages, plus $1.3 million in pre-judgment interest, $1.3 million in post-judgment interest (estimating two years for the duration of appeal), and court costs.

The Company believes that SEPCO has a number of legal grounds for appealing the judgment, all of which will be vigorously pursued. Based on the Company's understanding and judgment of the facts and merits of this case, including appellate defenses, and after considering the advice of counsel, the Company has determined that, although reasonably possible after exhaustion of all appeals, an adverse final outcome to this lawsuit is not probable. As such, the Company has not accrued any amounts with respect to this lawsuit. If the plaintiff and intervenor were to ultimately prevail in the appellate process, the Company currently estimates, based on the judgments to date, that SEPCO's potential liability would be up to $44.2 million, including interest and attorney's fees. The Company's assessment may change in the future due to occurrence of certain events, such as denied appeals, and such 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.

On February 20, 2012, the Company became aware that SEPCO was named as a defendant in the matter of Gery Muncey v. Southwestern Energy Production Company, et al filed in the District Court of San Augustine County in Texas on January 31, 2012. The plaintiff in this case is also the intervenor in the Tovah Energy matter described above and alleges various claims including fraud, misappropriation and breach of fiduciary duty that are purported as independent of the claims alleged in the Tovah Energy matter but arise from the substantially same circumstances involved in the Tovah Energy matter. The plaintiff is seeking value for various royalty and override ownership interests in wells drilled, disgorgement of profits and punitive damages. The Company has not accrued any amounts with respect to this lawsuit and cannot reasonably estimate the amount of any potential liability based on the Company's understanding and judgment of the facts and merits of this case.

In March 2010, the Company's subsidiary, SEECO, Inc., 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 described below, the Company believes the grand jury is investigating matters involving approximately 27 horizontal wells operated by SEECO in Arkansas, including whether appropriate leases or permits were obtained therefor and whether royalties and other production attributable to federal lands have been properly accounted for and paid. The Company believes it has fully complied with all requests related to the federal subpoena and delivered its affidavit to that effect. The Company and representatives of the Bureau of Land Management and the U.S. Attorney have had discussions since the production of the documents pursuant to the subpoena. In January 2011, the Company voluntarily produced additional materials informally requested by the government arising from these discussions. Although, to the Company's knowledge, no proceeding in this matter has been initiated against SEECO, the Company cannot predict whether or when one might be initiated. The Company intends to fully comply with any further requests and to cooperate with any related investigation. No assurance can be made as to the time or resources that will need to be devoted to this inquiry or the impact of the final outcome of the discussions or any related proceeding.

We are subject to various litigation, claims and proceedings that have arisen in the ordinary course of business. Management believes, individually or in aggregate, such litigation, claims and proceedings will not have a material adverse impact on our financial position or our results of operations but these matters are subject to inherent uncertainties and 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 our financial position, results of operations or cash flows for the period in which the effect becomes reasonably estimable. We accrue 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 under the symbol "SWN." On February 23, 2012, the closing price of our stock was $35.40 and we had 3,070 stockholders of record. The following table presents the high and low sales prices for closing market transactions as reported on the New York Stock Exchange.

	Range of Market Prices					
Quarter Ended	**2011**		2010		2009	
March 31	**$ 43.49**	**$ 36.12**	$ 51.65	$ 37.70	$ 34.14	$ 25.99
June 30	**$ 43.86**	**$ 38.02**	$ 44.99	$ 35.86	$ 45.65	$ 30.01
September 30	**$ 49.00**	**$ 33.33**	$ 38.83	$ 31.44	$ 45.08	$ 35.39
December 31	**$ 44.21**	**$ 31.94**	$ 38.45	$ 32.73	$ 50.62	$ 40.28

We have indefinitely suspended payment of quarterly cash dividends on our common stock.

Issuer Purchases of Equity Securities

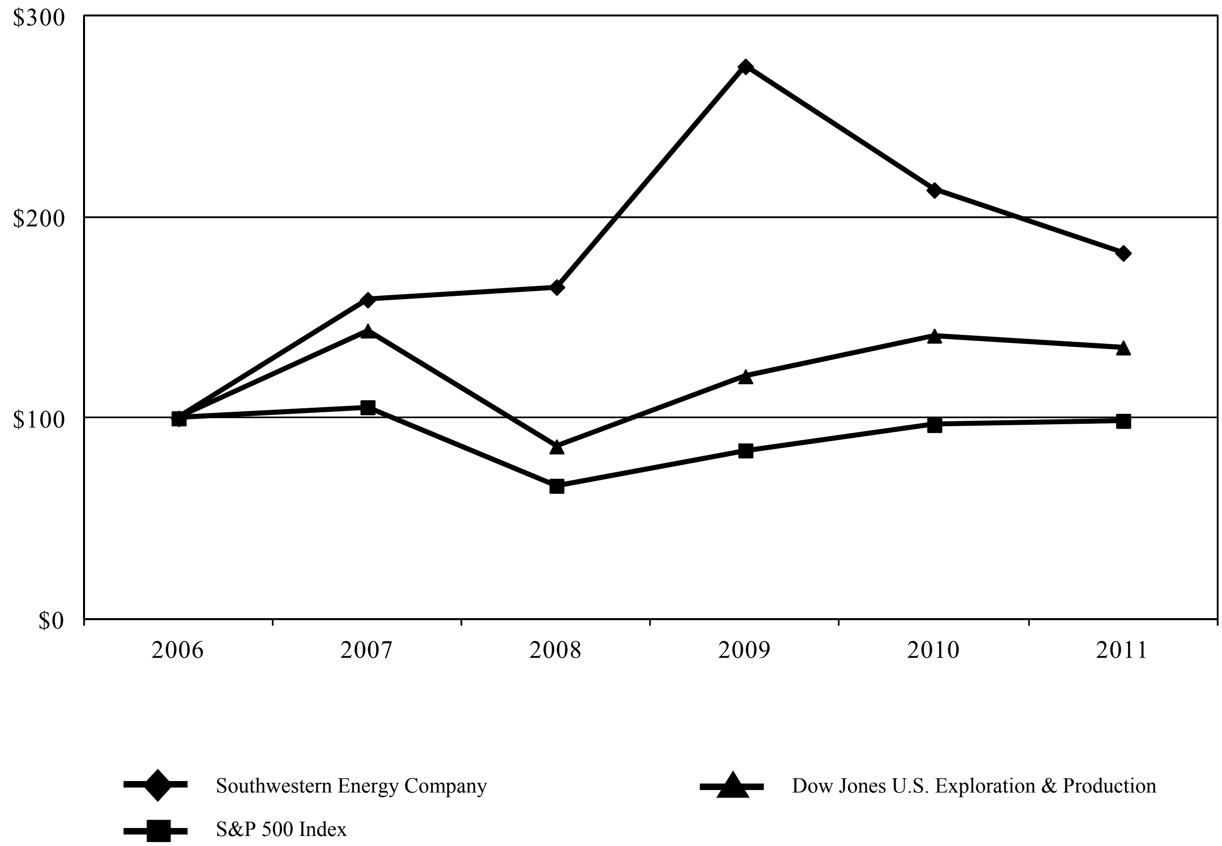
During 2011, we retired 7,220 shares for the payment of withholding taxes due on employee stock plan share issuances. All changes in common stock in treasury in 2011 were due to purchases and sales of shares held on behalf of participants in a non-qualified deferred compensation supplemental retirement 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 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, 2006, and that all dividends were reinvested. The stock performance shown on the graph below is not indicative of future price performance.



	12/31/06	12/31/07	12/31/08	12/31/09	12/31/10	**12/31/11**
Southwestern Energy Company	100	159	165	275	214	**182**
Dow Jones U.S. Exploration & Production	100	105	66	84	97	**99**
S&P 500 Index	100	144	86	121	141	**135**

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, 2011. 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."

	2011	2010	2009	2008	2007
	(in thousands except share, per share, stockholder data and percentages)				
Financial Review					
Operating revenues:					
Exploration and production	**$ 2,100,488**	$ 1,890,444	$ 1,593,231	$ 1,491,302	$ 795,944
Midstream services	**2,859,519**	2,453,840	1,603,332	2,173,971	961,994
Gas distribution and other	**3,268**	984	687	118,399	174,914
Intersegment revenues	**(2,010,369)**	(1,734,605)	(1,051,471)	(1,472,120)	(677,721)
	2,952,906	2,610,663	2,145,779	2,311,552	1,255,131
Operating costs and expenses:					
Gas purchases – midstream services	**709,091**	611,161	482,836	710,129	306,336
Gas purchases – gas distribution	**—**	—	—	61,439	85,445
Operating and general	**398,985**	337,334	259,159	209,536	166,095
Depreciation, depletion and amortization	**704,511**	590,332	493,658	414,408	293,914
Impairment of natural gas and oil properties	—	—	907,812	—	—
Taxes, other than income taxes	**65,518**	50,608	37,280	29,272	21,875
	1,878,105	1,589,435	2,180,745	1,424,784	873,665
Operating income (loss)	**1,074,801**	1,021,228	(34,966)	886,768	381,466
Interest expense, net	**24,075**	26,163	18,638	28,904	23,873
Other income (loss), net	**264**	427	1,449	4,404	(219)
Gain on sale of utility assets	**—**	—	—	57,264	—
Income (loss) before income taxes	**1,050,990**	995,492	(52,155)	919,532	357,374
Provision (benefit) for income taxes:					
Current	**4,198**	11,939	(64,969)	122,000	—
Deferred	**409,023**	379,720	48,606	228,999	135,855
	413,221	391,659	(16,363)	350,999	135,855
Net income (loss)	**637,769**	603,833	(35,792)	568,533	221,519
Less: net income (loss) attributable to noncontrolling interest	**—**	(285)	(142)	587	345
Net income (loss) attributable to Southwestern Energy	**$ 637,769**	$ 604,118	$ (35,650)	$ 567,946	$ 221,174
Return on equity(1)	**16.1%**	20.4%	(1.5%)	22.6%	13.3%
Net cash provided by operating activities	**$ 1,739,817**	$ 1,642,585	$ 1,359,376	$ 1,160,809	$ 622,735
Net cash used in investing activities	**$ (2,024,790)**	$ (1,725,631)	$ (1,780,604)	$ (792,078)	$ (1,513,497)
Net cash provided by (used in) financing activities	**$ 284,303**	$ 86,240	$ 238,135	$ (174,286)	$ 849,667
Common Stock Statistics (2)					
Earnings per share:					
Net income (loss) attributable to Southwestern stockholders – Basic	**$ 1.84**	$ 1.75	$ (0.10)	$ 1.66	$ 0.65
Net income (loss) attributable to Southwestern stockholders – Diluted	**$ 1.82**	$ 1.73	$ (0.10)	$ 1.64	$ 0.64
Cash dividends declared and paid per share	**$ —**	$ —	$ —	$ —	$ —
Book value per average diluted share(1)	**$ 11.34**	$ 8.49	$ 6.82	$ 7.27	$ 4.77
Market price at year-end	**$ 31.94**	$ 37.43	$ 48.20	$ 28.97	$ 27.86
Number of stockholders of record at year-end	**3,083**	3,043	2,639	2,497	2,275
Average diluted shares outstanding	**349,921,413**	349,310,666	343,420,568	346,245,938	347,442,660

(1) The return on equity and the book value per average diluted share calculations have been recalculated for 2008 and 2007 and now include an addition to equity for the Company's noncontrolling interest in partnership.

(2) Share and per share amounts in 2007 have been restated to reflect the two-for-one stock split effected in March 2008.

	2011	2010	2009	2008	2007
Capitalization (in thousands)					
Total debt	**$ 1,343,300**	$ 1,094,200	$ 998,700	$ 735,400	$ 978,800
Total equity	**3,969,304**	2,964,876	2,340,981	2,517,963	1,657,070
Total capitalization	**$ 5,312,604**	$ 4,059,076	$ 3,339,681	$ 3,253,363	$ 2,635,870
Total assets	**$ 7,902,897**	$ 6,017,463	$ 4,770,250	$ 4,760,158	$ 3,622,716
Capitalization ratios:					
Debt	**25.3%**	27.0%	29.9%	22.6%	37.1%
Equity	**74.7%**	73.0%	70.1%	77.4%	62.9%
Capital Investments (in millions) (1)					
Exploration and production	**1,977.5**	1,775.5	1,565.5	1,595.8	1,379.7
Midstream services	**160.8**	271.3	214.2	183.0	107.4
Other	**68.9**	73.3	29.4	17.4	16.0
	$ 2,207.2	$ 2,120.1	$ 1,809.1	$ 1,796.2	$ 1,503.1
Exploration and Production					
Natural gas:					
Production, Bcf	**499.4**	403.6	299.7	192.3	109.9
Average price per Mcf, including hedges	**$ 4.19**	$ 4.64	$ 5.30	$ 7.52	$ 6.80
Average price per Mcf, excluding hedges	**$ 3.56**	$ 3.93	$ 3.34	$ 7.73	$ 6.16
Oil:					
Production, MBbls	**97**	171	124	385	614
Average price per barrel, including hedges	**$ 94.08**	$ 76.84	$ 54.99	$ 107.18	$ 69.12
Average price per barrel, excluding hedges	**$ 94.08**	$ 76.84	$ 54.99	$ 107.18	$ 69.12
Total natural gas and oil production, Bcfe	**500.0**	404.7	300.4	194.6	113.6
Lease operating expenses per Mcfe	**$ 0.84**	$ 0.83	$ 0.77	$ 0.89	$ 0.73
General and administrative expenses per Mcfe	**$ 0.27**	$ 0.30	$ 0.35	$ 0.41	$ 0.48
Taxes, other than income taxes per Mcfe	**$ 0.11**	$ 0.11	$ 0.11	$ 0.13	$ 0.16
Proved reserves at year-end:					
Natural gas, Bcf	**5,887**	4,930	3,650	2,176	1,397
Oil, MMBbls	**1**	1	1	2	9
Total reserves, Bcfe	**5,893**	4,937	3,657	2,185	1,450
Midstream Services					
Gas volumes marketed, Bcf	**611.4**	495.8	382.5	258.0	145.7
Gas volumes gathered, Bcf	**745.7**	588.3	387.1	224.1	78.7

(1) Capital investments include increases of $4.3 million for 2011, $14.4 million for 2010, $12.2 million for 2009, $36.2 million for 2008 and a reduction of $20.6 million for 2007 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 crude 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 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 principally focused within the United States on development of an unconventional gas reservoir located on the Arkansas side of the Arkoma Basin, which we refer to as the Fayetteville Shale play. We are also actively engaged in exploration and production activities 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 recently commenced exploration operations in Arkansas and Louisiana testing an unconventional oil play targeting the Lower Smackover Brown Dense formation. 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, which we achieve in our E&P business through the drillbit. 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 primarily depend 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 play in Arkansas and the Marcellus Shale play 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 a significant decline in natural gas prices as evidenced by New York Mercantile Exchange ("NYMEX") natural gas prices ranging from a high of $13.58 per MMBtu in 2008 to a recent low of $2.32 per MMBtu in January 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

We reported net income attributable to Southwestern Energy of $637.8 million in 2011, or $1.82 per diluted share, up from net income attributable to Southwestern Energy of $604.1 million in 2010, or $1.73 per diluted share. We reported a net loss attributable to Southwestern Energy of $35.7 million, or $0.10 per diluted share, in 2009. The loss in 2009 included a $907.8 million, or $558.3 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 the first quarter of 2009. Our cash flow from operating activities increased 6% to $1,739.8 million in 2011 due to an increase in net income adjusted for non-cash expenses which was partially offset by changes in working capital accounts, and increased 21% to $1,642.6 million in 2010 due to an increase in net income adjusted for non-cash expenses and changes in working capital.

In 2011, our natural gas and oil production increased 24% to 500.0 Bcfe, up from 404.7 Bcfe in 2010. The 95.3 Bcfe increase in our 2011 production resulted from a 86.6 Bcf increase in net production from our Fayetteville Shale play and a 22.4 Bcf increase in net production from our Marcellus Shale properties, which more than offset a combined 13.7 Bcfe decrease in net production from our East Texas and Arkoma Basin properties. In 2010, our natural gas and oil production increased to 404.7 Bcfe, up from 300.4 Bcfe in 2009. We are targeting 2012 natural gas and oil production of 560 to 570 Bcfe, an increase of approximately 13% over our 2011 production, using midpoints. Our year-end reserves grew 19% in 2011 to 5,893 Bcfe, up from 4,937 Bcfe at the end of 2010 and 3,657 Bcfe at the end of 2009, primarily as a result of the continued development of our Fayetteville Shale play and Marcellus Shale play.

Our E&P segment reported operating income of $825.1 million in 2011, down from $829.5 million in 2010. Operating income in 2011 decreased $4.4 million over 2010 as the revenue impact of our 24% increase in production was more than offset by the 10% decline in our average realized gas prices and a $214.4 million increase in operating costs that resulted from our significant production growth. We recorded operating income from our E&P segment of $829.5 million in 2010, up from an operating loss of $157.7 million in 2009. The operating loss in 2009 included a $907.8 million non-cash ceiling test impairment of our United States natural gas and oil properties. Excluding the $907.8 million non-cash ceiling test impairment, operating income in 2010 increased $79.4 million over 2009 as a result of the revenue impact of our 35% increase in production which was partially offset by the 12% decline in our average realized gas prices and a $217.8 million increase in operating costs and expenses that resulted from our significant production growth.

Operating income for our Midstream Services segment was $248.0 million in 2011, up from $191.6 million in 2010 and $122.6 million in 2009. Operating income for our Midstream Services segment increased in 2011 due to an increase of $92.2 million in gathering revenues and an increase of $5.8 million in the margin generated from our natural gas marketing activities, which were partially offset by a $41.6 million increase in operating costs and expenses, exclusive of gas purchase costs, that resulted from our continued significant growth in volumes gathered. Volumes gathered grew to 745.7 Bcf in 2011 compared to 588.3 Bcf in 2010. Operating income for our Midstream Services segment increased in 2010 due to an increase of $110.4 million in gathering revenues and an increase of $5.5 million in the margin generated from our natural gas marketing activities, which were partially offset by a $46.9 million increase in operating costs and expenses, exclusive of gas purchase costs, that resulted from our significant growth in volumes gathered. Volumes gathered grew to 588.3 Bcf in 2010 compared to 387.1 Bcf in 2009.

We had total capital investments of $2,207.2 million in 2011, compared to $2,120.1 million in 2010 and $1,809.1 million in 2009. Of our total capital investments, $1,977.5 million was invested in our E&P segment in 2011 compared to $1,775.5 million and $1,565.5 million invested in our E&P segment in 2010 and 2009, 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 play and Marcellus Shale play, 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 2012 is flexible and is based on our expectation that natural gas prices will remain at current price levels. Should prices decline 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

	Year Ended December 31,		
	2011	2010	2009
Revenues (in thousands)	**$ 2,100,488**	$ 1,890,444	$ 1,593,231
Impairment of natural gas and oil properties (in thousands)	**$ —**	$ —	$ 907,812
Operating costs and expenses (in thousands)	**$ 1,275,350**	$ 1,060,982	$ 843,144
Operating income (loss) (in thousands)	**$ 825,138**	$ 829,462	$ (157,725)
Natural gas production (Bcf)	**499.4**	403.6	299.7
Oil production (MBbls)	**97**	171	124
Total production (Bcfe)	**500.0**	404.7	300.4
Average gas price per Mcf, including hedges	**$ 4.19**	$ 4.64	$ 5.30
Average gas price per Mcf, excluding hedges	**$ 3.56**	$ 3.93	$ 3.34
Average oil price per Bbl	**$ 94.08**	$ 76.84	$ 54.99
Average unit costs per Mcfe:			
Lease operating expenses	**$ 0.84**	$ 0.83	$ 0.77
General & administrative expenses	**$ 0.27**	$ 0.30	$ 0.35
Taxes, other than income taxes	**$ 0.11**	$ 0.11	$ 0.11
Full cost pool amortization	**$ 1.30**	$ 1.34	$ 1.51

Revenues

Revenues for our E&P segment were up $210.0 million, or 11%, in 2011 compared to 2010. Higher natural gas production volumes in 2011 increased revenues by $445.0 million while lower realized prices for our natural gas production decreased revenue by $227.9 million compared to 2010. E&P revenues were up $297.2 million, or 19%, in 2010 compared to 2009. Higher natural gas production volumes in 2010 increased revenues by $551.0 million while lower realized prices for our natural gas production decreased revenue by $265.1 million. We expect our natural gas production volumes to continue to increase due to our development of the Fayetteville Shale properties in Arkansas and our Marcellus Shale properties in Pennsylvania. Natural gas and oil prices are difficult to predict and subject to wide price fluctuations. As of February 23, 2012, we had hedged 266.4 Bcf of our remaining 2012 natural gas production and 185.2 Bcf of our 2013 natural gas production 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 2011, our natural gas and oil production increased 24% to 500.0 Bcfe, up from 404.7 Bcfe in 2010. The 95.3 Bcfe increase in our 2011 production resulted from a 86.6 Bcf increase in net production from our Fayetteville Shale play and a 22.4 Bcf increase in net production from our Marcellus Shale properties, which more than offset a combined 13.7 Bcfe decrease in net production from our East Texas and Arkoma Basin properties. Natural gas and oil production was up approximately 35% to 404.7 Bcfe in 2010, as compared to 2009, due to a 106.7 Bcf increase in net production from our Fayetteville Shale play and a 1.0 Bcf increase in net production from our Marcellus Shale properties, which more than offset a combined 3.4 Bcfe decrease in net production from out East Texas and Arkoma Basin properties. Our net production from the Fayetteville Shale play was 436.8 Bcf in 2011, up from 350.2 Bcf in 2010 and 243.5 Bcf in 2009.

We are targeting 2012 natural gas and oil production of 560 to 570 Bcfe, an increase of approximately 13% over our 2011 production, using midpoints. Approximately 465 to 470 Bcf of our 2012 targeted natural gas production is projected to come from our activities in the Fayetteville Shale play. Although we expect production volumes in 2012 to increase, we cannot guarantee our success in discovering, developing and producing reserves, including with respect to our Fayetteville Shale play. 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, 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, decreased 10% to $4.19 per Mcf in 2011 and decreased 12% to $4.64 per Mcf in 2010. The decrease in the average price realized in 2011 compared to 2010 primarily reflects the decrease 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 gas price in 2010 (see additional discussion below). The decrease in the average price realized in 2010 compared to 2009 primarily reflected the decrease in average market prices, which was partially offset by the positive effect of our price hedging activities in 2010. We periodically enter into various hedging and other financial arrangements with respect to a portion of our projected natural gas and crude 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 gas price $0.63 per Mcf in 2011, compared to an increase of $0.71 per Mcf in 2010 and an increase of $1.96 per Mcf in 2009. Disregarding the impact of hedges, the average price received for our natural gas production in 2011 was $0.37 per Mcf lower than 2010 and $0.48 lower than the average monthly NYMEX settlement price for 2011.

At December 31, 2011, we had basis protected on approximately 269.4 Bcf of our 2012 expected natural gas production through financial hedging activities and physical sales arrangements at a basis differential to NYMEX gas prices of approximately $0.02 per Mcf.

In addition to the basis hedges discussed above, at December 31, 2011, we had NYMEX fixed price hedges in place on notional volumes of 185.9 Bcf of our remaining 2012 natural gas production at an average price of $5.02 per MMBtu and collars in place on notional volumes of 80.5 Bcf of our 2012 natural gas production at an average floor and ceiling price of $5.50 and $6.67 per MMBtu, respectively. At December 31, 2011, we had NYMEX fixed price hedges in place on notional volumes of 185.2 Bcf of our 2013 natural gas production.

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, while transportation charges and fuel charges also reduce the price received. Assuming a NYMEX commodity price of $3.00 per Mcf for 2012, and disregarding the impact of hedges, we expect our total gas sales discount to NYMEX to be $0.45 to $0.55 per Mcf.

We realized an average price of $94.08 per barrel for our oil production for the year ended December 31, 2011, up approximately 22% from the prior year. The 2010 average realized price of $76.84 per barrel was up 40% from 2009. We did not hedge any of our 2011, 2010 or 2009 oil production.

Operating Income

Operating income from our E&P segment decreased $4.4 million to $825.1 million in 2011 from $829.5 million in 2010 as the revenue impact of our 24% increase in production was more than offset by the 10% decrease in our average realized gas prices and a $214.4 million increase in operating costs that resulted from our significant production growth. We recorded an operating loss from our E&P segment of $157.7 million in 2009. The operating loss in 2009 includes a $907.8 million 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 the first quarter of 2009. Excluding the $907.8 million non-cash ceiling test impairment, operating income in 2010 increased $79.4 million over 2009 as a result of the revenue impact of our 35% increase in production which was partially offset by a 12% decline in our average realized gas prices and a $217.8 million increase in operating costs and expenses that resulted from our significant production growth.

Operating Costs and Expenses

Lease operating expenses per Mcfe for the E&P segment were $0.84 in 2011, compared to $0.83 in 2010 and $0.77 in 2009. Lease operating expenses per unit of production increased in 2011 primarily due to increased gathering costs associated with our Fayetteville Shale operations. Lease operating expenses per unit of production increased in 2010 compared to 2009 primarily due to increased gathering, compression and water disposal costs associated with our Fayetteville Shale operations. We expect our per unit operating cost for this segment to range between $0.86 and $0.90 per Mcfe in 2012.

General and administrative expenses for the E&P segment were $0.27 per Mcfe in 2011, down from $0.30 per Mcfe in 2010 and $0.35 per Mcfe in 2009. The decreases in general and administrative costs per Mcfe in 2011 and 2010 were due to the effects of our increased production volumes. In total, general and administrative expenses for the E&P segment were $134.8 million in 2011, $120.3 million in 2010 and $105.0 million in 2009. The increases in general and administrative expenses since 2009 were primarily a result of increased payroll, incentive compensation, employee-related costs and professional fees associated with the expansion of our E&P operations due to the continued development of the Fayetteville Shale play and Marcellus Shale play. These increases accounted for $11.1 million, or 76%, of the 2011 increase and $13.6 million, or 89%, of the 2010 increase. We added 106 new E&P employees during 2011 compared to 253 employees added in 2010.

We expect our per unit cost for general and administrative expenses in 2012 to range between $0.29 and $0.33 per Mcfe. The expected increase in our per unit general and administrative costs in 2012 is due to general increases in our G&A and increased compensation costs associated with ongoing development of our Fayetteville Shale and Marcellus Shale plays. Future changes in our general and administrative expenses for this segment are primarily dependent upon our salary costs, level of pension expense, amount of stock-based compensation expense and the amount of incentive compensation paid to our employees and level and intensity 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, and 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 $0.11 in 2011, 2010, and 2009, respectively. 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. Effective January 1, 2009, the State of Arkansas changed the severance tax on natural gas wells to be based on the market value of natural gas produced.

Our full cost pool amortization rate averaged $1.30 per Mcfe for 2011, $1.34 per Mcfe for 2010 and $1.51 per Mcfe for 2009. The decline in the average amortization rate for 2011 compared to 2010 was primarily the result of lower acquisition and development costs and sale of certain East Texas properties in 2011 and 2010. The decline in the average amortization rate for 2010 compared to 2009 was primarily the result of lower acquisition and development costs combined with the $907.8 million non-cash ceiling test impairment recorded in the first quarter of 2009 and the sale of certain East Texas oil and natural gas leases and wells in the second quarter of 2010 as the proceeds from the sale were appropriately credited to the full cost pool. 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 play.

Unevaluated costs excluded from amortization were $942.9 million at the end of 2011 compared to $712.1 million at the end of 2010 and $595.4 million at the end of 2009. Unevaluated costs excluded from amortization at the end of 2011 included $27.9 million related to our properties in Canada. The increase in unevaluated costs since December 31, 2010 primarily resulted from a $172.9 million increase in our undeveloped leasehold acreage and seismic costs as well as a $103.7 million increase in our drilling activity in our wells in progress. 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

	Year Ended December 31,		
	2011	2010	2009
		($ in millions)	
Revenues – marketing	**$ 2,451.3**	$ 2,137.8	$ 1,397.7
Revenues – gathering	**$ 408.2**	$ 316.0	$ 205.6
Gas purchases – marketing	**$ 2,418.1**	$ 2,110.4	$ 1,375.8
Operating costs and expenses	**$ 193.4**	$ 151.8	$ 104.9
Operating income	**$ 248.0**	$ 191.6	$ 122.6
Gas volumes marketed (Bcf)	**611.4**	495.8	382.5
Gas volumes gathered (Bcf)	**745.7**	588.3	387.1

Revenues

Revenues from our marketing activities were up 15% to $2,451.3 million for 2011 compared to 2010. The increase in marketing revenues resulted from increases in the volumes marketed which partially offset a decrease in the prices received for volumes marketed. Revenues from our marketing activities were up 53% to $2,137.8 million for 2010 compared to 2009. The increase in marketing revenues for 2010 resulted from increases in the volumes marketed combined with an increase in the prices received for volumes marketed. The average price received for volumes marketed decreased 7% in 2011 compared to 2010, and increased 18% in 2010 compared to 2009. Volumes marketed increased 23% in 2011 compared to 2010, and increased 30% in 2010 compared to 2009. Of the total volumes marketed, production from our E&P operated wells accounted for 94% in 2011, 95% in 2010 and 92% in 2009. Increases and decreases in marketing revenues due to changes in commodity prices are largely offset by corresponding changes in gas purchase expenses.

Revenues from our gathering activities were up 29% to $408.2 million for 2011 compared to 2010, and were up 54% to $316.0 million for 2010 compared to 2009. The increases in gathering revenues primarily resulted from a 27% increase in gas volumes gathered in 2011 compared to 2010 and a 52% increase in gas volumes gathered in 2010 compared to 2009. Substantially all of the increases in gathering revenues for 2011 and 2010 resulted from increases in the volumes gathered from our operated production from the Fayetteville Shale play. Gathering volumes, revenues and expenses for this segment are expected to continue to grow as production from our Fayetteville Shale and Marcellus Shale plays increase.

Operating Income

Operating income from our Midstream Services segment increased 29% to $248.0 million in 2011 and increased 56% to $191.6 million in 2010. The increases in operating income reflect the substantial increases in gas volumes gathered and marketed which resulted primarily from our increased E&P production volumes. The increase in operating income for 2011 compared to 2010 was due to an increase of $92.2 million in gathering revenues and an increase of $5.8 million in the margin generated from our gas marketing activities, which were partially offset by a $41.6 million increase in operating costs and expenses, exclusive of purchased gas costs. The increase in operating income for 2010 compared to 2009 was due to a $110.4 million increase in gathering revenues and an increase of $5.5 million in the margin generated from our gas marketing activities, which were partially offset by a $46.9 million increase in operating costs and expenses, exclusive of purchased gas costs.

The margin generated from gas marketing activities was $33.2 million for 2011, compared to $27.4 million for 2010 and $21.9 million for 2009. Margins are primarily driven by volumes of 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 23% increase in volumes marketed in 2011 and a 30% increase in volumes marketed in 2010, 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 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 $24.1 million in 2011, a decrease of $2.1 million compared to 2010, primarily due to a increase in capitalized interest. Interest capitalized increased to $45.7 million in 2011 from $32.9 million in 2010, primarily due to an increase in our weighted average interest rate and average borrowed balance under our credit facility during 2011, which had a weighted average interest rate of 2.06% for 2011 and an increase in our unevaluated properties.

In 2010, interest expense, net of capitalization, was $26.2 million, an increase of $7.5 million compared to 2009 primarily due to a decrease in capitalized interest. Interest capitalized decreased to $32.9 million in 2010 from $40.2 million in 2009, primarily due to a decrease in our weighted average interest rate during 2010 as a result of the increase in our average borrowed balance under our credit facility, which had a weighted average interest rate of 1.06% for 2010.

Income Taxes

Our effective tax rate was 39.3% in 2011 and 2010 and 31.5% in 2009. Our effective tax rate, excluding the $907.8 million non-cash ceiling test impairment of our natural gas and oil properties, would have been 39.0% for 2009. In general, differences between our effective tax rate and the statutory tax rate of 35% primarily result from the effect of certain state income taxes and permanent items attributable to book-tax differences.

Stock-Based Compensation Expense

We recognized expense of $10.6 million and capitalized $8.5 million for stock-based compensation in 2011, compared to $9.8 million expensed and $6.8 million capitalized in 2010 and $10.2 million expensed and $5.9 million capitalized in 2009. We refer you to Note 1 to the consolidated financial statements for additional discussion of our equity based compensation plans.

LIQUIDITY AND CAPITAL RESOURCES

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

During 2012, assuming natural gas prices remain at current levels, we expect to draw on a portion of the funds available under the Credit Facility to fund the portion of our planned capital investments (discussed below under "Capital Investments"), that are expected to exceed the net cash generated by our operations. We refer you to Note 7 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.

Net cash provided by operating activities increased 6% to $1.7 billion in 2011, 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 increased 21% to $1.6 billion in 2010, due to an increase in net income adjusted for non-cash expenses and changes in working capital accounts. For 2011, requirements for our capital investments were funded from our cash generated by operating activities, borrowings under our Credit Facility and the proceeds from the sale of certain East Texas oil and natural gas properties. Net cash from operating activities provided 80% of our cash requirements for capital investments in 2011, 79% in 2010 and 76% in 2009.

At December 31, 2011, our capital structure consisted of 25% debt and 75% 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 2012. The credit status of the financial institutions participating in our Credit Facility could adversely impact our ability to borrow funds under the Credit Facility. While we believe all of the lenders under the facility have the ability to provide funds, we cannot predict whether each will be able to meet its obligation.

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 the overall state of the economy. The price received for our production is also influenced by our commodity hedging activities, as more fully discussed in Note 5 to the consolidated financial statements included in this Form 10-K and Item 7A, "Quantitative and Qualitative Disclosures about Market Risk." 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 2011, up from $2.1 billion in 2010. Capital investments include an increase of $4.3 million in 2011, an increase of $14.4 million in 2010 and an increase of $12.2 million in 2009 related to the change in accrued expenditures between years. Our E&P segment investments in 2011 were $2.0 billion, compared to $1.8 billion in 2010 and $1.6 billion in 2009.

	2011	2010	2009
		(in thousands)	
Exploration and production	**$ 1,977,493**	$ 1,775,518	$ 1,565,450
Midstream services	**160,776**	271,316	214,208
Other	**68,905**	73,231	29,459
	$ 2,207,174	$ 2,120,065	$ 1,809,117

Our capital investments for 2012 are planned to be $2.1 billion, consisting of approximately $1.8 billion for E&P, $190 million for Midstream Services and $90 million for corporate and other purposes. Of the approximate $1.8 billion, we expect to allocate approximately $1.1 billion to our Fayetteville Shale play. Our planned level of capital investments in 2012 is expected to allow us to continue our progress in the Fayetteville Shale and Marcellus Shale programs and explore and develop other existing natural gas and oil properties and generate new drilling prospects. As discussed above, our 2012 capital investment program is expected to be funded through cash flow from operations and borrowings under our Credit Facility. The planned capital program for 2012 is flexible and can be modified, including downward, if the low natural gas price environment persists for an extended period of time. We will reevaluate our proposed investments as needed to take into account prevailing market conditions and, if natural gas prices change significantly in 2012, we could change our planned investments.

Financing Requirements

Our total debt outstanding was $1,343.3 million at December 31, 2011, compared to $1,094.2 million at December 31, 2010.

In February 2011, we amended and restated our unsecured revolving credit facility, increasing the borrowing capacity to $1.5 billion and extending the maturity date to February 2016. The amount available under the revolving credit facility may be increased to $2.0 billion at any time upon the Company's agreement with its existing or additional lenders. We had $671.5 and $421.2 million outstanding under its revolving credit facility at December 31, 2011 and December 31, 2010, respectively.

The interest rate on our Credit Facility is calculated based upon our public debt rating and is currently 200 basis points over LIBOR. At February 23, 2012, our publicly traded notes are rated BBB- by Standard and Poor's and we have a Corporate Family Rating of Baa3 by Moody's. Any downgrades in our public debt ratings could increase our cost of funds under the Credit Facility.

Our Credit Facility contains covenants which impose certain restrictions on us. Under the Credit Facility, we must keep our total debt at or below 60% of our total capital, and must maintain a ratio of EBITDA to interest expense of 3.5 or above. Our Credit Facility's financial covenants with respect to capitalization percentages exclude the noncontrolling interest in equity, the effects of non-cash entries that result from any full cost ceiling impairments, hedging activities and our pension and other postretirement liabilities. Therefore, under our Credit Facility, our capital structure at December 31, 2011 would have been 27% debt and 73% equity. We were in compliance with all of the covenants of our Credit Facility at December 31, 2011. Although we do not anticipate any violations of our financial covenants, our ability to comply with those covenants 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 would have to decrease our capital investment plans.

At December 31, 2011, our capital structure consisted of 25% debt and 75% equity compared to 27% debt and 73% equity at December 31, 2010. Our debt percentage of total capital at December 31, 2011 decreased in 2011, primarily due to our profitable results and the minimal funding of our capital investments and operational needs through debt. Equity at December 31, 2011 included an accumulated other comprehensive gain of $424.9 million related to our hedging activities and a loss for $15.9 million related to our pension and other postretirement liabilities. The amount recorded in equity for our hedging activities is based on current market values for our hedges at December 31, 2011 and does not necessarily reflect the value that we will receive or pay when the hedges are ultimately settled, nor does it take into account revenues to be received associated with the physical delivery of sales volumes hedged.

Our hedges allow us to ensure a certain level of cash flow to fund our operations. At February 23, 2012, we had NYMEX commodity price hedges in place on 266.4 Bcf, or approximately 47% of our targeted 2012 natural gas production and 185.2 Bcf of our expected 2013 natural gas production. The amount of long-term debt we incur 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. At December 31, 2011, 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 or 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 at December 31, 2011, 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)		
Demand charges[1]	**$2,095,722**	$ 212,160	$ 453,249	$ 469,850	$ 960,463
Debt	**1,343,300**	1,200	2,400	673,900	665,800
Interest on senior notes	**386,590**	64,304	130,105	117,588	74,593
Operating leases[2]	**268,088**	69,728	122,720	59,426	16,214
Operating agreements[3]	**613,622**	459,523	145,401	8,698	—
Compression services[4]	**107,130**	42,115	45,744	17,563	1,708
Purchase obligations[5]	**50,221**	50,221	—	—	—
Other obligations[6]	**213,697**	78,285	14,856	3,154	117,402
	$5,078,370	$ 977,536	$ 914,475	$1,350,179	$1,836,180

(1) As of December 31, 2011, our Midstream Services segment had commitments for demand transportation charges on various pipelines, including approximately $1.0 billion related to the FEP pipeline and $0.7 billion related to the Boardwalk Pipeline.

(2) Operating leases include costs for compressors, aircraft, vehicles, office space and equipment under non-cancelable operating leases expiring through 2019. Additionally, this includes $58.1 million for leases of 14 drilling rigs and related equipment through 2014.

(3) As of December 31, 2011, our E&P segment had commitments for approximately $548.3 million to companies for fracture stimulation services, which are cancellable under certain circumstances.

(4) As of December 31, 2011, our Midstream Services segment had commitments of approximately $100.6 million and our E&P segment had commitments of approximately $6.5 million for compression services associated primarily with our Fayetteville Shale play operations.

(5) Purchase obligations consist of outstanding purchase orders under existing agreements. As of December 31, 2011, our Midstream Services segment had outstanding purchase obligations of $12.7 million relating to compression units.

(6) 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 8 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 $127.5 million for asset retirement obligations primarily relating to oil and gas properties, approximately $12.0 million for funding of benefit plans, approximately $9.6 million for various information technology support and data subscription agreements, approximately $7.1 million for insurance premium financing and approximately $7.4 million related to seismic services.

We refer you to Note 7 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 $12.7 million to our pension plans and $0.2 million to our postretirement benefit plan in 2012. For 2011, we contributed $12.5 million to our pension plans and contributed $0.1 million to our postretirement benefit plan. At December 31, 2011 we recognized a liability of $20.5 million as a result of the underfunded status of our pension and other postretirement benefit plans compared to a liability of $15.9 million at December 31, 2010. For further information regarding our pension and other postretirement benefit plans, we refer you to Note 11 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 positive working capital of $93.4 million at December 31, 2011 and negative working capital of $113.1 million at December 31, 2010. Current assets increased $397.4 million during 2011 primarily due to a $384.1 million increase in our current hedging asset which was partially offset by a $9.7 million decrease in accounts receivable. Current liabilities increased $190.9 million primarily due to a $150.1 million increase in our current deferred income taxes related to our hedging activities, a $40.2 million increase in accounts payable, and a $2.4 million increase in advances from partners.

Natural Gas in Underground Storage

We currently have one facility owned by our E&P segment that contains natural gas in underground storage. Natural gas in storage that is expected to be cycled within the next 12 months is recorded in current assets. This current portion of natural gas in storage is classified as inventory and is carried at the lower of cost or market. At December 31, 2011 and 2010, the current portion of natural gas in storage was $7.8 million and $10.0 million, respectively. The non-current portion of natural gas in storage is classified in property and equipment and carried at cost. The carrying value of the non-current gas is evaluated for recoverability whenever events or changes in circumstances indicate that it may not be recoverable.

The natural gas in inventory for the E&P segment is used primarily to supplement production in meeting the segment's contractual commitments, especially during periods of colder weather. In determining the lower of cost or market for storage gas, we utilize the natural gas futures market in assessing the price we expect to be able to realize for our natural gas in inventory. A significant decline in the future market price of natural gas could require a write-down of our natural gas in underground storage carrying cost.

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 reported 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 percent (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. Effective December 31, 2009, companies using the full cost method were 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. For quarter and annual periods ending prior to December 31, 2009, prices in effect at the date of each accounting quarter, including the impact of derivatives qualifying as cash flow hedges, were required to be used.

Using the 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 and $92.71 per barrel for West Texas Intermediate oil, 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, 2011. Cash flow hedges of natural gas production in place increased this ceiling amount by approximately $262.5 million at December 31, 2011. Decreases in average market prices as well as changes in production rates, levels of reserves, evaluation of costs excluded from amortization, future development costs and service costs could result in future ceiling test impairments. Using the first-day-of-the-month prices of natural gas for the first two months of 2012 and NYMEX strip prices for the remainder of 2012, as applicable, the prices required to be used to determine the ceiling limit could result in a ceiling test write-down in the first quarter of 2012 and are likely to require ceiling test write-downs in each of the remaining quarters in 2012. At December 31, 2010, the ceiling value of the Company's reserves was calculated based upon year-end quoted market prices of $4.38 per MMBtu for Henry Hub natural gas and $75.96 per barrel for West Texas Intermediate oil, and at December 31, 2009, the ceiling value of the Company's reserves was calculated based upon year-end quoted market prices of $3.87 per MMBtu for Henry Hub natural gas and $57.65 per barrel for West Texas Intermediate oil. 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. At March 31, 2009, the net capitalized costs of our natural gas and oil properties exceeded the ceiling by approximately $558.3 million (net of tax) and resulted in a non-cash ceiling test impairment using quarter-end market prices of $3.63 per MMBtu for Henry Hub natural gas and $46.00 per barrel for West Texas Intermediate oil.

All of our costs directly associated with the acquisition and evaluation of properties in New Brunswick, Canada relating to our exploration program at December 31, 2011 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 over eight years of experience in petroleum engineering, including the estimation of oil and natural gas reserves, who reports to our Senior Vice President – Corporate Development. Our Senior Vice President – Corporate Development has more than 30 years of experience in reservoir engineering, including the estimation of oil and gas reserves in multiple basins both in the United States and internationally. On our behalf, the Senior 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 Senior 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 and final authority over the estimates of our proved reserves rests with our Board of Directors.

In each of the past three years, revisions to our proved reserve estimates represented no greater than 7% of our total proved reserve estimates, which we believe is indicative of the effectiveness of our internal controls. 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 55% of our total reserve base at December 31, 2011. 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 90% of 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 90% present value as of December 31, 2011, accounted for approximately 92% of our total proved reserves and approximately 98% 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. For the year-ended December 31, 2011, on January 30, 2012, NSAI issued its audit opinion as to the reasonableness of our reserve estimates, stating that our estimated proved oil and 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 reported. 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 reported reserve quantities. Our standardized measure and reserve quantities at December 31, 2011, were $3,450.8 million and 5,893.2 Bcfe, respectively. An assumed decrease of $1.00 per Mcf in the average 2011 natural gas price used to price our reserves would have resulted in an approximate $1,472.6 million decline in our standardized measure and an approximate decrease of 947 Bcfe of our reported reserves. The decline in reserve quantities, assuming this decrease in natural gas price, would have the impact of increasing our unit of production amortization of the full cost pool. 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 crude 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. From 2006 through 2008, we established a portfolio of hedges relating to approximately 60% to 80% of our annual production. However, only 45%, 30% and 52% of our 2009, 2010, and 2011 production, respectively, was hedged due to credit and overall market events of 2008 and 2009 as well as the low commodity price environment throughout 2010 and 2011. The primary market risks related to our derivative contracts are the volatility in market prices and basis differentials for natural gas and crude 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 qualifying for hedge accounting treatment or any ineffective portion of a properly designated hedge is recognized immediately in earnings. For the year ended December 31, 2011, we recorded an unrealized gain of $5.2 million related to basis differential swaps that did not qualify for hedge accounting in addition to a $4.2 million loss related to the change in estimated ineffectiveness of our commodity cash flow hedges. 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 11 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, 2011 benefit obligation and the periodic benefit cost to be recorded in 2012, the discount rate assumed is 5.00%. For the 2012 periodic benefit cost, the expected return assumed is 7.50%. This compares to a discount rate of 5.50% and an expected return of 7.50% used in 2011.

Using the assumed rates discussed above, we recorded total benefit cost of $11.5 million in 2011 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 2011 pension expense:

	Increase (Decrease) of Annual Pension Expense	
	50 Basis Point Increase	50 Basis Point Decrease
	(in thousands)	
Discount rate	$ (623)	$ 682
Expected long-term rate of return	$ (293)	$ 293

At December 31, 2011, we recognized a liability of $20.5 million, compared to $15.9 million at December 31, 2010, related to our pension and other postretirement benefit plans. During 2011, we also made cash payments totaling $12.6 million to fund our pension and other postretirement benefit plans. In 2012, we expect to make cash payments totaling $12.9 million to fund our pension and other postretirement benefit plans and recognize pension expense of $12.0 million and a postretirement benefit expense of $2.2 million.

New Accounting Standards Implemented in this Report

In January 2011, we implemented certain provisions of Accounting Standards Update No. 2010-06, "Fair Value Measurements and Disclosures (Topic 820) – Improving Disclosures about Fair Value Measurements" ("Update 2010-06"). Update 2010-06 requires entities to provide a reconciliation of purchases, sales, issuance and settlements of anything valued with a Level 3 method, which is used to price the hardest to value instruments. The implementation did not have an impact on our results of operations, financial position or cash flows.

In July 2011, the FASB issued Accounting Standards Update No. 2011-05, *Presentation of Comprehensive Income* ("Update 2011-05"), which amends Topic 200, *Comprehensive Income*. Update 2011-05 eliminates the option to present components of 'other comprehensive income' ("OCI") in the statement of changes in stockholders' equity, and requires presentation of total comprehensive income and components of net income in a single statement of comprehensive income, or in two separate, consecutive statements. Update 2011-05 requires presentation of reclassification adjustments for items transferred from OCI to net income on the face of the financial statements where the components of net income and the components of OCI are presented. The amendments do not change current treatment of items in OCI, transfer of items from OCI, or reporting items in OCI net of the related tax impact. Update 2011-05 is effective for fiscal years and interim periods beginning after December 15, 2011. The implementation of these changes did not have an impact on the Company's results of operations, financial position or cash flows.

Accounting Standards Not Yet Implemented

In May 2011, the FASB issued guidance on fair value measurement and disclosure requirements outlined in Accounting Standards Update No. 2011-04, *Fair Value Measurement (Topic 820)–Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS* ("Update 2011-04"). Update 2011-04 expands existing fair value disclosure requirements, particularly for Level 3 inputs, including: quantitative disclosure of the unobservable inputs and assumptions used in the measurement; description of the valuation processes in place and sensitivity of the fair value to changes in unobservable inputs and interrelationships between those inputs; the level of items (in the fair value hierarchy) that are not measured at fair value in the balance sheet but whose fair value must be disclosed; and the use of a nonfinancial asset if it differs from the highest and best use assumed in the fair value measurement. The amendments in Update 2011-04 must be applied prospectively and are effective during interim and annual periods beginning after December 15, 2011. The implementation of the disclosure requirement is not expected to have a material impact on the Company's consolidated results of operations, financial position or cash flows.

In December 2011, the FASB issued guidance on offsetting assets and liabilities and disclosure requirements in Accounting Standards Update No. 2011-11, *Disclosures about Offsetting Assets and Liabilities* ("Update 2011-11"). Update 2011-11 requires that entities disclose both gross and net information about instruments and transactions eligible for offset in the statement of financial position as well as instruments and transaction s subject to an agreement similar to a master netting agreement. In addition, the standard requires disclosure of collateral received and posted in connection with master netting agreements or similar arrangements. Update 2011-11 is effective for annual reporting periods beginning on or after January 1, 2013, and interim periods within those annual periods. The implementation of the disclosure requirement is not expected to have a material impact on the Company's consolidated results of operations, financial position or cash flows.

In December 2011, the FASB issued guidance on accumulated other comprehensive income in Accounting Standards Update 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 2011-12"). Update 2011-12 defers the specific requirement to present items that are classified from accumulated other comprehensive income to net income separately with their respective components of net income and other comprehensive income, as promulgated under Update 2011-05. Update 2011-12 is effective for annual reporting periods beginning on or after December 15, 2011, and interim periods within those annual periods. The Company is currently evaluating the impact that the implementation of the disclosure requirement is expected to have on the Company's consolidated results of operations, financial position or cash flows.

See further discussion of our significant accounting policies in Note 1 to the consolidated financial statements.

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 of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. 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 play overall as well as relative to other productive shale 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 for the Fayetteville Shale play and Marcellus Shale play;
- our future property 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;
- 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.

At December 31, 2011, approximately 45% 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 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 crude oil swap agreements and 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 customers and their dispersion across geographic areas. No single customer accounted for greater than 10% of revenues at December 31, 2011. 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, 2011. At December 31, 2011, we had $1,343.3 million of total debt with a weighted average interest rate of 4.87% and we had $671.5 million of indebtedness outstanding under our Credit Facility. Interest rate swaps may be used to adjust interest rate exposures when deemed appropriate. We do not have any interest rate swaps in effect currently.

	Expected Maturity Date							Fair Value
	2012	2013	2014	2015	2016	Thereafter	Total	12/31/11
	($ in millions)							
Fixed Rate	$ 1.2	$ 1.2	$ 1.2	$ 1.2	$ 1.2	$ 665.8	$ 671.8	$ 773.6
Average Interest Rate	7.15%	7.15%	7.15%	7.15%	7.15%	7.47%	7.47%	—
Variable Rate	—	—	—	—	$ 671.5	—	$ 671.5	$ 671.5
Average Interest Rate	—	—	—	—	2.28%	—	2.28%	—

Commodities Risk

We use over-the-counter natural gas and crude oil swap agreements and options to hedge sales of our production and to hedge activity in our Midstream Services segment 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 crude 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 which 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. At December 31, 2011, the fair value of our financial instruments related to natural gas production and gas-in-storage was a $704.8 million asset.

	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, 2011 ($ in millions)
Natural Gas:						
Fixed Price Swaps:						
2012	185.9	$ 5.02	$ —	$ —	$ —	$ 322.8
2013	185.2	$ 5.06	$ —	$ —	$ —	$ 201.1
Floating Price Swaps:						
2012	5.7	$ 5.21	$ —	$ —	$ —	$ (1.2)
Costless-Collars:						
2012	80.5	$ —	$ 5.50	$ 6.67	$ —	$ 178.9
Basis Swaps:						
2012	36.6	$ —	$ —	$ —	$ 0.09	$ 1.5
2013	30.1	$ —	$ —	$ —	$ 0.07	$ 1.1
2014	9.1	$ —	$ —	$ —	$ (0.03)	$ 0.6

At December 31, 2011, our basis swaps did not qualify for hedge accounting treatment. Changes in the fair value of derivatives that do not qualify as cash flow hedges are recorded in natural gas and oil sales. For the year ended December 31, 2011, we recorded an unrealized gain of $5.2 million related to the basis swaps that did not qualify for hedge accounting treatment and an unrealized loss of $4.2 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, 2010, we had outstanding fixed price basis differential swaps on 12.0 Bcf of 2011 natural gas production that did not qualify for hedge treatment.

Midstream Services

At December 31, 2011, our Midstream Services segment had outstanding fair value hedges in place on 0.1 Bcf of natural gas for 2012. These hedges are a mixture of floating-price swap purchases and sales relating to our natural gas marketing activities. These hedges have contract months from January 2012 to March 2012 and have a net fair value liability of less than $0.1 million as of December 31, 2011.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) under the Exchange Act. 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 internal control over financial reporting. Our management assessed the effectiveness of our internal control over financial reporting as of December 31, 2011. 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 and procedures may deteriorate.

Our management used the criteria set forth in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) to perform its assessment. Based on this assessment, our management, including our Chief Executive Officer and our Chief Financial Officer, concluded, that as of December 31, 2011, our internal control over financial reporting was effective based on those criteria.

The effectiveness of our internal control over financial reporting as of December 31, 2011 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report that follows.

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of Southwestern Energy Company:

In our opinion, the accompanying 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, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011 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, 2011, based on criteria established in *Internal Control - Integrated Framework* 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 the accompanying 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.

As discussed in Note 1 to the consolidated financial statements, the Company changed the manner in which it estimates the quantities of oil and natural gas reserves in 2009 and the limitation on its capitalized costs as of December 31, 2009.

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

PricewaterhouseCoopers LLP
Houston, Texas
February 27, 2012

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	For the years ended December 31,		
	2011	2010	2009
	(in thousands, except share/per share amounts)		
Operating Revenues:			
Gas sales	**$ 2,080,241**	$ 1,856,241	$ 1,578,256
Gas marketing	**714,123**	615,913	488,663
Oil sales	**9,085**	13,111	6,843
Gas gathering	**149,973**	122,912	74,281
Other	**(516)**	2,486	(2,264)
	2,952,906	2,610,663	2,145,779
Operating Costs and Expenses:			
Gas purchases – midstream services	**709,091**	611,161	482,836
Operating expenses	**240,944**	191,771	136,541
General and administrative expenses	**158,041**	145,563	122,618
Depreciation, depletion and amortization	**704,511**	590,332	493,658
Impairment of natural gas and oil properties	**—**	—	907,812
Taxes, other than income taxes	**65,518**	50,608	37,280
	1,878,105	1,589,435	2,180,745
Operating Income (Loss)	**1,074,801**	1,021,228	(34,966)
Interest Expense:			
Interest on debt	**65,421**	57,144	55,581
Other interest charges	**4,306**	1,935	3,266
Interest capitalized	**(45,652)**	(32,916)	(40,209)
	24,075	26,163	18,638
Other Income, Net	**264**	427	1,449
Income (Loss) Before Income Taxes	**1,050,990**	995,492	(52,155)
Provision (Benefit) for Income Taxes:			
Current	**4,198**	11,939	(64,969)
Deferred	**409,023**	379,720	48,606
	413,221	391,659	(16,363)
Net Income (Loss)	**637,769**	603,833	(35,792)
Less: Net Loss Attributable to Noncontrolling Interest	**—**	(285)	(142)
Net Income (Loss) Attributable to Southwestern Energy	**$ 637,769**	$ 604,118	$ (35,650)
Earnings Per Share:			
Net income (loss) attributable to Southwestern Energy stockholders-Basic	**$ 1.84**	$ 1.75	$ (0.10)
Net income (loss) attributable to Southwestern Energy stockholders-Diluted	**$ 1.82**	$ 1.73	$ (0.10)
Weighted Average Common Shares Outstanding:			
Basic	**347,205,316**	345,581,568	343,420,568
Effect of:			
Stock options	**2,475,053**	3,512,241	—
Restricted stock awards	**241,044**	216,857	—
Diluted	**349,921,413**	349,310,666	343,420,568

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

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

	For the years ended December 31,		
	2011	2010	2009
		(in thousands)	
Net income (loss)	**$ 637,769**	$ 603,833	$ (35,792)
Change in derivatives:			
Reclassification to earnings (1)	**(194,693)**	(182,619)	(376,259)
Ineffectiveness (2)	**2,518**	4,145	(6,031)
Change in fair value of derivative instruments (3)	**520,552**	179,649	218,699
Total change in derivatives	**328,377**	1,175	(163,591)
Change in value of pension and other postretirement liabilities:			
Current period net loss (4)	**(4,129)**	(2,148)	(477)
Current period prior service cost (5)	—	16	(57)
Less: amortization of prior service cost included in net periodic pension cost (6)	**766**	674	736
Total change in value of pension and other postretirement liabilities	**(3,363)**	(1,458)	202
Change in currency translation adjustment	**(561)**	(18)	—
Comprehensive income (loss)	**962,222**	603,532	(199,181)
Less: comprehensive loss attributable to the noncontrolling interest	**—**	(285)	(142)
Comprehensive income (loss) attributable to Southwestern Energy	**$ 962,222**	$ 603,817	$ (199,039)

(1) Net of ($126.6), ($118.9), and ($234.1) million in taxes for the years ended December 31, 2011, 2010 and 2009, respectively.

(2) Net of $1.6, $2.6, and ($3.8) million in taxes for the years ended December 31, 2011, 2010 and 2009, respectively.

(3) Net of $338.4, $119.5, and $137.7 million in taxes for the years ended December 31, 2011, 2010 and 2009, respectively.

(4) Net of ($2.7), ($2.0), and ($0.2) million in taxes for the years ended December 31, 2011, 2010 and 2009, respectively.

(5) Net of less than $0.1 and ($0.1) million in taxes for the years ended December 31, 2010 and 2009, respectively.

(6) Net of $0.5, $0.6, and $0.5 million in taxes for the years ended December 31, 2011, 2010 and 2009, respectively.

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

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31, 2011	December 31, 2010
	(in thousands)	
ASSETS		
Current Assets:		
Cash and cash equivalents	**$ 15,627**	$ 16,055
Accounts receivable	**341,915**	351,573
Inventories	**46,234**	35,098
Hedging asset	**514,465**	130,412
Other	**60,037**	47,755
Total current assets	**978,278**	580,893
Property and Equipment:		
Natural gas and oil properties, using the full cost method, including $942.9 million in 2011 and $712.1 million in 2010 excluded from amortization	**9,544,708**	7,749,863
Gathering systems	**980,647**	817,465
Other	**535,464**	413,557
Total property and equipment	**11,060,819**	8,980,885
Less: Accumulated depreciation, depletion and amortization	**4,415,339**	3,682,688
	6,645,480	5,298,197
Other Assets	**279,139**	138,373
TOTAL ASSETS	**$ 7,902,897**	$ 6,017,463
LIABILITIES AND EQUITY		
Current Liabilities:		
Current portion of long-term debt	**$ 1,200**	$ 1,200
Accounts payable	**514,071**	473,890
Taxes payable	**40,691**	50,051
Interest payable	**20,565**	19,954
Advances from partners	**84,082**	81,705
Hedging liability	**12,458**	7,685
Current deferred income taxes	**194,163**	44,089
Other	**17,683**	15,409
Total current liabilities	**884,913**	693,983
Long-Term Debt	**1,342,100**	1,093,000
Other Liabilities:		
Deferred income taxes	**1,586,798**	1,130,292
Long-term hedging liability	**55**	40,188
Pension and other postretirement liabilities	**20,338**	15,777
Other long-term liabilities	**99,389**	79,347
	1,706,580	1,265,604
Commitments and Contingencies		
Equity:		
Southwestern Energy stockholders' equity:		
Common stock, $0.01 par value; authorized 1,250,000,000 shares in 2011 and 2010; issued 349,058,501 shares in 2011 and 347,733,839 in 2010	**3,491**	3,477
Additional paid-in capital	**903,399**	862,423
Retained earnings	**2,656,214**	2,018,445
Accumulated other comprehensive income	**408,428**	83,975
Common stock in treasury, 98,889 shares in 2011 and 156,636 in 2010	**(2,228)**	(3,444)
Total Equity	**3,969,304**	2,964,876
TOTAL LIABILITIES AND EQUITY	**$ 7,902,897**	$ 6,017,463

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

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the years ended December 31,		
	2011	2010	2009
		(in thousands)	
Cash Flows From Operating Activities			
Net income (loss)	**$ 637,769**	$ 603,833	$ (35,792)
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	**707,966**	591,943	495,291
Impairment of natural gas and oil properties	—	—	907,812
Deferred income taxes	**409,023**	379,720	48,606
Unrealized (gain) loss on derivatives	**(281)**	(4,289)	5,309
Stock-based compensation expense	**10,550**	9,820	10,177
Other	**991**	(1,348)	9,625
Change in assets and liabilities:			
Accounts receivable	**9,659**	(88,488)	(8,519)
Inventories	**(12,975)**	5,099	11,779
Accounts payable	**11,490**	65,782	(21,739)
Taxes payable	**(9,360)**	24,551	(6,451)
Interest payable	**610**	179	(1,082)
Advances from partners	**2,377**	29,299	(18,197)
Tax benefit for stock-based compensation	**(14,626)**	—	—
Other assets and liabilities	**(13,376)**	26,484	(37,443)
Net cash provided by operating activities	**1,739,817**	1,642,585	1,359,376
Cash Flows From Investing Activities			
Capital investments	**(2,184,474)**	(2,073,174)	(1,780,165)
Proceeds from sale of property and equipment	**154,526**	350,227	818
Transfers to restricted cash	**(85,055)**	(356,035)	—
Transfers from restricted cash	**85,055**	356,035	—
Other	**5,158**	(2,684)	(1,257)
Net cash used in investing activities	**(2,024,790)**	(1,725,631)	(1,780,604)
Cash Flows From Financing Activities			
Payments on current portion of long-term debt	**(1,200)**	(1,200)	(61,200)
Payments on revolving long-term debt	**(3,445,900)**	(2,958,100)	(1,371,700)
Borrowings under revolving long-term debt	**3,696,200**	3,054,800	1,696,200
Change in bank drafts outstanding	**24,637**	(11,545)	(30,920)
Revolving credit facility costs	**(10,211)**	—	—
Proceeds from exercise of common stock options	**6,412**	3,897	5,755
Tax benefit for stock-based compensation	**14,626**	—	—
Other	**(261)**	(1,612)	—
Net cash provided by financing activities	**284,303**	86,240	238,135
Effect of exchange rate changes on cash	**242**	(323)	—
Increase (decrease) in cash and cash equivalents	**(428)**	2,871	(183,093)
Cash and cash equivalents at beginning of year	**16,055**	13,184	196,277
Cash and cash equivalents at end of year	**$ 15,627**	$ 16,055	$ 13,184

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

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
STATEMENTS OF EQUITY

	Southwestern Energy Stockholders							
	Common Stock		Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income	Common Stock in Treasury	Noncontrolling Interest	Total
	Shares Issued	Amount						
	(in thousands)							
Balance at December 31, 2008	343,625	$ 3,436	$ 811,492	$1,449,977	$ 247,665	$ (4,740)	$ 10,133	$ 2,517,963
Comprehensive loss:								
Net Loss	—	—	—	(35,650)	—	—	(142)	(35,792)
Other comprehensive loss	—	—	—	—	(163,389)	—	—	(163,389)
Total comprehensive loss							(142)	(199,181)
Stock-based compensation	—	—	16,003	—	—	—	—	16,003
Exercise of stock options	2,153	22	5,733	—	—	—	—	5,755
Issuance of restricted stock	312	3	(3)	—	—	—	—	—
Cancellation of restricted stock	(10)	—	—	—	—	—	—	—
Issuance of stock awards	1	—	65	—	—	—	—	65
Treasury stock – non-qualified plan	—	—	204	—	—	407	—	611
Distributions to noncontrolling interest in partnership	—	—	—	—	—	—	(235)	(235)
Balance at December 31, 2009	346,081	$ 3,461	$ 833,494	$1,414,327	$ 84,276	$ (4,333)	$ 9,756	$ 2,340,981
Comprehensive income (loss):								
Net Income (loss)	—	—	—	604,118	—	—	(285)	603,833
Other comprehensive loss	—	—	—	—	(301)	—	—	(301)
Total comprehensive income (loss)							(285)	603,532
Stock-based compensation	—	—	16,569	—	—	—	—	16,569
Exercise of stock options	1,293	12	3,885	—	—	—	—	3,897
Issuance of restricted stock	392	4	(4)	—	—	—	—	—
Cancellation of restricted stock	(30)	—	—	—	—	—	—	—
Tax withholding – stock compensation	(3)	—	(112)	—	—	—	—	(112)
Issuance of stock awards	1	—	37	—	—	—	—	37
Treasury stock – non-qualified plan	—	—	771	—	—	889	—	1,660
Distributions to noncontrolling interest in partnership	—	—	—	—	—	—	(188)	(188)
Purchase of noncontrolling interest in partnership	—	—	7,783	—	—	—	(9,283)	(1,500)
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

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

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
NOTES TO 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 located on the Arkansas side of the Arkoma Basin, which the Company refers to as the Fayetteville Shale play. The Company is also actively engaged in exploration and production activities 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. The Company has recently commenced exploration operations in southern Arkansas and northern Louisiana testing a new unconventional horizontal oil play targeting the Lower Smackover Brown Dense formation. 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 reported amounts of assets and liabilities and disclosure of contingent assets and liabilities, if any, at the date of the financial statements, and the reported 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.

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. In 2010, the Company purchased the non-controlling interest in Overton Partners, L.P.

Revenue Recognition

Gas and oil sales. 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, gas sales and oil sales are not recognized for deliveries in excess of the Company's net revenue interest, while 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. At December 31, 2011, the Company had overproduction of 6.1 Bcf valued at $22.5 million and underproduction of 6.4 Bcf valued at $22.9 million. At December 31, 2010, the Company had overproduction of 3.9 Bcf valued at $13.3 million and underproduction of 3.7 Bcf valued at $12.8 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. The Company gathers its natural gas, as well as some 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 include gains of $0.9 million, $2.5 million and $3.4 million in 2011, 2010 and 2009, respectively, primarily related to the sale of 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 $47.7 million and $23.1 million at December 31, 2011 and 2010, respectively.

Inventory

Inventory recorded in current assets includes $7.8 million at December 31, 2011 and $10.0 million at December 31, 2010, for natural gas in underground storage owned by the Company's E&P segment, and $38.4 million at December 31, 2011 and $25.1 million at December 31, 2010 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 is classified in inventory and carried at the lower of cost or market. The non-current portion of the natural gas is classified in property and equipment and carried at cost. 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 $19.5 million at December 31, 2011 and $20.6 million at December 31, 2010 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 percent (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. 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 $4.12 per MMBtu and $92.71 per barrel for West Texas Intermediate oil, 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, 2011. Cash flow hedges of natural gas production in place increased this ceiling amount by approximately $262.5 million at December 31, 2011. At December 31, 2010, this ceiling amount of the Company's reserves was calculated based upon average quoted market prices of $4.38 per MMBtu for Henry Hub natural gas and $75.96 per barrel for West Texas Intermediate oil, and at December 31, 2009, the ceiling value of the

Company's reserves was calculated based upon year-end quoted market prices of $3.87 per MMBtu for Henry Hub natural gas and $57.65 per barrel for West Texas Intermediate oil. 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. At March 31, 2009, the net capitalized costs of our natural gas and oil properties exceeded the ceiling by approximately $558.3 million (net of tax) and resulted in a non-cash ceiling test impairment in the first quarter of 2009.

All of our costs directly associated with the acquisition and evaluation of properties in New Brunswick, Canada relating to our exploration program at December 31, 2011 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.

On December 31, 2009, the Company implemented certain provisions of FASB ASC 932, "Extractive Activities-Oil and Gas," as updated by Accounting Standards Update No. 2010-03, "Extractive Activities-Oil and Gas (Topic 932)" ("FASB ASC 932"), which (a) expand the definition of oil- and gas-producing activities; (b) require energy companies to value their proved reserves by averaging the price from the first day of each month from the previous 12 months instead of using a year-end price; and (c) allow for additional drilling locations to be classified as proved undeveloped reserves assuming such locations are supported by reliable technologies. The Company accounted for the FASB ASC 932 changes as a change in accounting principle that is inseparable from a change in accounting estimate and will account for the change prospectively. The Company is not able to disclose the effects resulting from the implementation of these changes on the amount of proved reserves and disclosed quantities because personnel and time constraints made it infeasible for the Company to perform a second internal reserve estimation process under the prior standards on its approximately 4,850 properties.

Gathering Systems. The Company's investment in gathering systems is primarily related to its Fayetteville Shale play in Arkansas and Marcellus Shale play 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 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 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 swaps and options contracts to hedge sales of natural gas. Gains and losses resulting from the settlement of hedge contracts have been recognized in gas sales 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 are reported 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 swaps and option contacts as well as basis swap contracts that do not qualify for hedge accounting treatment are recognized currently in gas sales in the consolidated statements 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 for a discussion of the Company's hedging activities.

Earnings Per Share

Basic earnings per common share attributable to Southwestern Energy stockholders is computed by dividing net income (loss) attributable to Southwestern Energy by the weighted average number of common shares outstanding during each year. The diluted earnings per share attributable to Southwestern Energy stockholders 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.

For the year ended December 31, 2011, outstanding options for 3,577,104 shares with an average exercise 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, 2010, outstanding options for 4,753,530 shares with an average exercise price of $9.42 were included in the calculation of diluted shares. Options for 548,160 shares were excluded from the calculation because they would have had an antidilutive effect. For the year ended December 31, 2009, 6,683,085 of the Company's outstanding options with an average exercise price of $8.33 were excluded from the calculation of diluted shares because they would have had an antidilutive effect.

For the year ended December 31, 2011, 241,044 shares of restricted stock were included from the calculation of diluted shares. The calculation excluded 135,352 shares of restricted stock because they would have had an antidilutive effect. For the year ended December 31, 2010, 700,512 shares of restricted stock were included from the calculation of diluted shares. The calculation excluded 39,600 shares of restricted stock because they would have had an antidilutive effect. For the year ended December 31, 2009, the number of shares of restricted stock excluded from the calculation of diluted shares was 836,861 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,		
	2011	2010	2009
		(in thousands)	
Cash paid during the year for interest, net of amounts capitalized	$ 19,159	$ 24,049	$ 16,453
Cash paid (received) during the year for income taxes	4,198	14,368	(41,469)
Increase in noncash property additions	30,389	46,588	28,951

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, 2011, 98,889 shares were accounted for as treasury stock, compared to 156,636 shares at December 31, 2010.

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 2011, we implemented certain provisions of Accounting Standards Update No. 2010-06, "Fair Value Measurements and Disclosures (Topic 820) – Improving Disclosures about Fair Value Measurements" ("Update 2010-06"). Update 2010-06 requires entities to provide a reconciliation of purchases, sales, issuance and settlements of anything valued with a Level 3 method, which is used to price the hardest to value instruments. The implementation did not have an impact on our results of operations, financial position or cash flows.

In July 2011, the FASB issued Accounting Standards Update No. 2011-05, *Presentation of Comprehensive Income* ("Update 2011-05"), which amends Topic 200, *Comprehensive Income*. Update 2011-05 eliminates the option to present components of 'other comprehensive income' ("OCI") in the statement of changes in stockholders' equity, and requires presentation of total comprehensive income and components of net income in a single statement of comprehensive income, or in two separate, consecutive statements. Update 2011-05 requires presentation of reclassification adjustments for items transferred from OCI to net income on the face of the financial statements where the components of net income and the components of OCI are presented. The amendments do not change current treatment of items in OCI, transfer of items from OCI, or reporting items in OCI net of the related tax impact. Update 2011-05 is effective for fiscal years and interim periods beginning after December 15, 2011. The implementation of these changes did not have an impact on the Company's results of operations, financial position or cash flows.

Accounting Standards Not Yet Implemented

In May 2011, the FASB issued guidance on fair value measurement and disclosure requirements outlined in Accounting Standards Update No. 2011-04, *Fair Value Measurement (Topic 820)–Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS* ("Update 2011-04"). Update 2011-04 expands existing fair value disclosure requirements, particularly for Level 3 inputs, including: quantitative disclosure of the unobservable inputs and assumptions used in the measurement; description of the valuation processes in place and sensitivity of the fair value to changes in unobservable inputs and interrelationships between those inputs; the level of items (in the fair value hierarchy) that are not measured at fair value in the balance sheet but whose fair value must be disclosed; and the use of a nonfinancial asset if it differs from the highest and best use assumed in the fair value measurement. The amendments in Update 2011-04 must be applied prospectively and are effective during interim and annual periods beginning after December 15, 2011. The implementation of the disclosure requirement is not expected to have a material impact on the Company's consolidated results of operations, financial position or cash flows.

In December 2011, the FASB issued guidance on offsetting assets and liabilities and disclosure requirements in Accounting Standards Update No. 2011-11, *Disclosures about Offsetting Assets and Liabilities* ("Update 2011-11"). Update 2011-11 requires that entities disclose both gross and net information about instruments and transactions eligible for offset in the statement of financial position as well as instruments and transaction s subject to an agreement similar to a master netting agreement. In addition, the standard requires disclosure of collateral received and posted in connection with master netting agreements or similar arrangements. Update 2011-11 is effective for annual reporting periods beginning on or after January 1, 2013, and interim periods within those annual periods. The implementation of the disclosure requirement is not expected to have a material impact on the Company's consolidated results of operations, financial position or cash flows.

In December 2011, the FASB issued guidance on accumulated other comprehensive income in Accounting Standards Update 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 2011-12"). Update 2011-12 defers the specific requirement to present items that are classified from accumulated other comprehensive income to net income separately with their respective components of net income and other comprehensive income, as promulgated under Update 2011-05. Update 2011-12 is effective for annual reporting periods beginning on or after December 15, 2011, and interim periods within those annual periods. The Company is currently evaluating the impact that the implementation of the disclosure requirement is expected to have on the Company's consolidated results of operations, financial position or cash flows.

(2) DIVESTITURES

In May 2011, we sold certain oil and natural gas leases, wells and gathering equipment in East Texas for approximately $118.1 million. The sale included only the producing rights to the Haynesville and Middle Bossier Shale intervals in approximately 9,717 net acres. The net production from the Haynesville and Middle Bossier Shale intervals in this acreage was approximately 7.0 MMcf per day and proved net reserves were approximately 37.1 Bcf when the sale was closed in May 2011.

At closing, the Company deposited $85.0 million of proceeds from this sale with a qualified intermediary to facilitate potential like-kind exchange transactions pursuant to Section 1031 of the Internal Revenue Code. The remaining funds were classified as restricted cash in the consolidated balance sheet and, unless utilized for one or more like-kind exchange transactions, were restricted in their use until November 2011. For the year ended December 31, 2011, the Company utilized $82.1 million of these restricted funds for like-kind exchange transactions pursuant to Section 1031 of the Internal Revenue Code.

In June 2010, we sold certain oil and natural gas leases, wells and gathering equipment in East Texas for approximately $357.8 million. The sale included only the producing rights to the Haynesville and Middle Bossier Shale intervals in approximately 20,063 net acres. The net production from the Haynesville and Middle Bossier Shale intervals in this acreage was approximately 13.5 MMcf per day and proved net reserves were approximately 55.4 Bcf when the sale was closed in June 2010.

(3) PREPAID EXPENSES

The components of prepaid expenses included in other current assets as of December 31, 2011 and 2010 consisted of the following:

	2011	2010
	(in thousands)	
Prepaid drilling costs	**$ 42,775**	$ 21,997
Prepaid insurance	**7,275**	7,690
Total	**$ 50,050**	$ 29,687

(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 at December 31, 2011 and 2010:

	2011	2010
	(in thousands)	
Proved properties	**$ 8,601,818**	$ 7,037,746
Unproved properties	**942,890** (1)	712,117 (1)
Total capitalized costs	**9,544,708**	7,749,863
Less: Accumulated depreciation, depletion and amortization	**4,092,410**	3,444,477
Net capitalized costs	**$ 5,452,298**	$ 4,305,386

(1) Includes $27.9 and $10.7 million related to our exploration program in New Brunswick, Canada at December 31, 2011 and 2010, respectively.

The table below sets forth the composition of net unevaluated costs excluded from amortization as of December 31, 2011.

	2011	2010	2009	Prior	**Total**
			(in thousands)		
Property acquisition costs	$ 254,622	$ 143,165	$ 44,513	$ 110,767	**$ 553,067** (1)
Exploration and development costs	190,240	20,844	29,527	67,335	**307,946** (1)
Capitalized interest	14,651	12,901	10,261	44,064	**81,877** (1)
	$ 459,513	$ 176,910	$ 84,301	$ 222,166	**$ 942,890**

(1) Property acquisition costs include $7.5 million, exploration costs include $19.2 million and capitalized interest includes $1.2 million related to our exploration program in New Brunswick, Canada.

Of the total net unevaluated costs excluded from amortization at December 31, 2011, approximately $83.2 million is related to unevaluated seismic costs in the Fayetteville Shale play, approximately $101.3 million is related to acquisition of undeveloped properties in the Company's Fayetteville Shale play, approximately $179.4 million is related to acquisition of undeveloped properties in the Company's Marcellus Shale play and approximately $245.0 million is related to acquisition of undeveloped properties in the Company's New Ventures, excluding our exploration program in New Brunswick, Canada. The Company has $27.9 million of unevaluated costs related to its exploration program in Canada. Additionally, the Company has approximately $180.2 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:

	2011	2010	2009
	(in thousands, except per Mcfe amounts)		
Proved property acquisition costs	**$ 17**	$ —	$ 4,372
Unproved property acquisition costs	**262,886** (1)	229,909 (1)	115,217
Exploration costs	**63,419** (2)	27,062 (2)	52,178
Development costs	**1,633,784**	1,524,453	1,358,109
Capitalized costs incurred	**1,960,106**	1,781,424	1,529,876
Full cost pool amortization per Mcfe	**$ 1.30**	$ 1.34	$ 1.51

(1) Includes $0.2 million and $2.5 million in 2011 and 2010, respectively, related to our exploration program in New Brunswick, Canada.
(2) Includes $18.4 million and $8.2 million in 2011 and 2010, respectively, related to our exploration program in New Brunswick, Canada.

Capitalized interest is included as part of the cost of natural gas and oil properties. The Company capitalized $43.4 million, $32.9 million and $40.2 million during 2011, 2010 and 2009, respectively, based on the Company's weighted average cost of borrowings used to finance the expenditures.

In addition to capitalized interest, the Company also capitalized internal costs of $147.7 million, $139.2 million and $112.9 million during 2011, 2010 and 2009, respectively. These internal costs were directly related to acquisition, exploration and development activities and are included as part of the 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:

	2011	2010	2009
		(in thousands)	
Sales	**$ 2,100,488**	$ 1,890,444	$ 1,593,231
Production (lifting) costs	**(469,153)**	(376,939)	(259,588)
Depreciation, depletion and amortization	**(666,107)**	(561,003)	(474,014)
Impairment of natural gas and oil properties	**—**	—	(907,812)
	965,228	952,502	(48,183)
Provision (benefit) for income taxes	**376,049**	371,281	(15,650)
Results of operations	**$ 589,179**	$ 581,221	$ (32,533)

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. ("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 90%, 85% and 88% of the present worth of the Company's total proved reserves at December 31, 2011, 2010 and 2009, 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.

The following table summarizes the changes in the Company's proved natural gas and oil reserves for 2011, 2010 and 2009 all of which were located in the United States:

	2011		2010		2009	
	Natural Gas (MMcf)	**Oil (MBbls)**	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)
Proved reserves, beginning of year	**4,929,980**	**1,219**	3,650,303	1,059	2,175,528	1,507
Revisions of previous estimates	**34,505**	**(125)**	309,292	50	94,930	(346)
Extensions, discoveries and other additions	**1,459,428**	**2**	1,429,439	281	1,683,264	22
Production	**(499,433)**	**(97)**	(403,636)	(171)	(299,698)	(124)
Acquisition of reserves in place	**13**	**—**	—	—	1,795	—
Disposition of reserves in place	**(37,286)**	**(3)**	(55,418)	—	(5,516)	—
Proved reserves, end of year	**5,887,207**	**996**	4,929,980	1,219	3,650,303	1,059
Proved developed reserves:						
Beginning of year	**2,687,238**	**1,173**	1,972,767	1,028	1,336,370	1,352
End of year	**3,254,018**	**983**	2,687,238	1,173	1,972,767	1,028
Proved undeveloped reserves:						
Beginning of year	**2,242,742**	**46**	1,677,536	31	839,158	155
End of year	**2,633,189**	**13**	2,242,742	46	1,677,536	31

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 at December 31, 2011, 2010 and 2009 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:

	2011	2010 (in thousands)	2009
Future cash inflows	**$22,012,205**	$19,620,254	$12,533,868
Future production costs	**(8,080,207)**	(6,826,915)	(4,488,884)
Future development costs	**(3,425,185)**	(3,025,433)	(2,367,206)
Future income tax expense	**(3,366,175)**	(3,143,571)	(1,569,242)
Future net cash flows	**7,140,638**	6,624,335	4,108,536
10% annual discount for estimated timing of cash flows	**(3,689,838)**	(3,610,585)	(2,306,718)
Standardized measure of discounted future net cash flows	**$ 3,450,800**	$ 3,013,750	$ 1,801,818

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 in 2011 and 2010, and utilized year-end pricing in 2009. Prices used for the standardized measure above were average market prices of $4.12 per MMBtu for natural gas and $92.71 per barrel for oil in 2011, average market prices of $4.38 per MMBtu for natural gas and $75.96 per barrel for oil in 2010, and year-end prices of $3.87 per MMBtu for natural gas and $57.65 per barrel for oil in 2009. 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 2011, 2010 and 2009:

	2011	2010	2009
		(in thousands)	
Standardized measure, beginning of year	**$ 3,013,750**	$ 1,801,818	$ 2,109,262
Sales and transfers of natural gas and oil produced, net of production costs	**(1,632,156)**	(1,516,571)	(1,330,256)
Net changes in prices and production costs	**(381,131)**	706,062	(1,321,404)
Extensions, discoveries, and other additions, net of future production and development costs	**1,163,992**	1,205,464	976,449
Acquisition of reserves in place	**30**	—	1,878
Sales of reserves in place	**(11,761)**	(6,269)	(4,430)
Revisions of previous quantity estimates	**34,221**	324,284	88,261
Accretion of discount	**426,245**	230,355	302,439
Net change in income taxes	**(103,643)**	(746,971)	413,399
Changes in estimated future development costs	**70,492**	(10,558)	204,005
Previously estimated development costs incurred during the year	**564,894**	353,560	218,625
Changes in production rates (timing) and other	**305,867**	672,576	143,590
Standardized measure, end of year	**$ 3,450,800**	$ 3,013,750	$ 1,801,818

(5) DERIVATIVES AND RISK MANAGEMENT

The Company is exposed to volatility in market prices and basis differentials for natural gas and crude 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. At December 31, 2011 and 2010, the Company's derivative financial instruments consisted of price swaps, costless-collars and basis 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.
Costless-collars	Arrangements that contain a fixed floor price (put) and a fixed ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, the Company receives the fixed price and pays the market price. If the market price is between the call and the put strike price, no payments are due from either party.
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.

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.

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 at December 31, 2011 and 2010:

	Derivative Assets			
	December 31, 2011		December 31, 2010	
	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
	(in thousands)			
Derivatives designated as hedging instruments:				
Fixed and floating price swaps	Hedging asset	$ 333,479	Hedging asset	$ 81,797
Costless-collars	Hedging asset	179,080	Hedging asset	48,582
Fixed and floating price swaps	Other assets	201,081	Other assets	5,086
Costless-collars	Other assets	—	Other assets	72,827
Total derivatives designated as hedging instruments		$ 713,640		$ 208,292
Derivatives not designated as hedging instruments:				
Basis swaps	Hedging asset	$ 1,906	Hedging asset	$ 33
Basis swaps	Other assets	1,797	Other assets	—
Total derivatives not designated as hedging instruments		$ 3,703		$ 33
Total derivative assets		$ 717,343		$ 208,325

	Derivative Liabilities			
	December 31, 2011		December 31, 2010	
	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
	(in thousands)			
Derivatives designated as hedging instruments:				
Fixed and floating price swaps	Hedging liability	$ 11,849	Hedging liability	$ 1,774
Costless-collars	Hedging liability	209	Hedging liability	3,903
Fixed and floating price swaps	Long-term hedging liability	—	Long-term hedging liability	22,334
Costless-collars	Long-term hedging liability	—	Long-term hedging liability	17,854
Total derivatives designated as hedging instruments		$ 12,058		$ 45,865
Derivatives not designated as hedging instruments:				
Basis swaps	Hedging liability	$ 400	Hedging liability	$ 2,008
Basis swaps	Long-term hedging liability	55	Long-term hedging liability	—
Total derivatives not designated as hedging instruments		$ 455		$ 2,008
Total derivative liabilities		$ 12,513		$ 47,873

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, 2011, the Company had cash flow hedges on the following volumes of natural gas production and gas-in-underground storage (in Bcf):

Year	Fixed price swaps	Costless-collars
2012	185.9	80.5
2013	185.2	—

As of December 31, 2011, the Company recorded a gain in accumulated other comprehensive income related to its hedging activities of $424.9 million net of a deferred income tax liability of $276.2 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, 2011 remain unchanged, the Company would expect to transfer an aggregate after-tax net gain of approximately $303.2 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 $320.1 million for the year ended December 31, 2011 compared to a realized gain of $301.5 million for the year ended December 31, 2010. 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, 2011 and 2010.

	Gain Recognized in Other Comprehensive Income (Effective Portion)	
	For the years ended December 31,	
Derivative Instrument	2011	2010
	(in thousands)	
Fixed price swaps	$ 714,740	$ 166,722
Costless-collars	$ 144,126	$ 132,438

		Gain Reclassified from Accumulated Other Comprehensive Income into Earnings (Effective Portion)	
	Classification of Gain Reclassified from Accumulated Other Comprehensive Income into Earnings	For the years ended December 31,	
Derivative Instrument	(Effective Portion)	2011	2010
		(in thousands)	
Fixed price swaps	Gas Sales	$ 256,229	$ 230,707
Costless-collars	Gas Sales	$ 65,047	$ 70,775

		Loss Recognized in Earnings (Ineffective Portion)	
	Classification of Loss Recognized in Earnings	For the years ended December 31,	
Derivative Instrument	(Ineffective Portion)	2011	2010
		(in thousands)	
Fixed price swaps	Gas Sales	$ (4,018)	$ (4,769)
Costless-collars	Gas Sales	$ (137)	$ (1,999)

Fair Value Hedges

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. As of December 31, 2011 and December 31, 2010, the Company had no material fair value hedges.

Other Derivative Contracts

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 do not qualify as cash flow hedges are recorded on the balance sheet at their fair values under hedging assets, other assets and hedging liabilities, as applicable and all realized and unrealized gains and losses related to these contracts are recognized immediately in the consolidated statements of operations as a component of natural gas sales.

As of December 31, 2011, the Company had basis swaps on natural gas production that did not qualify for hedge accounting treatment of 36.6 Bcf, 30.1 Bcf, and 9.1 Bcf for 2012, 2013, and 2014, respectively.

The following tables summarizes the before tax effect of basis swaps that did not qualify for hedge accounting on the uncondensed consolidated statements of operations for the years ended December 31, 2011 and 2010.

Derivative Instrument	Income Statement Classification of Unrealized Gain	Unrealized Gain Recognized in Earnings For the years ended December 31, 2011	2010
		(in thousands)	
Basis swaps	Gas Sales	$ 5,222	$ 11,434

Derivative Instrument	Income Statement Classification of Realized Loss	Realized Loss Recognized in Earnings For the years ended December 31, 2011	2010
		(in thousands)	
Basis swaps	Gas Sales	$ (2,135)	$ (12,098)

(6) FAIR VALUE MEASUREMENTS

The carrying amounts and estimated fair values of the Company's financial instruments as of December 31, 2011 and 2010 were as follows:

	December 31, 2011		December 31, 2010	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
	(in thousands)			
Cash and cash equivalents	**$ 15,627**	**$ 15,627**	$ 16,055	$ 16,055
Unsecured revolving credit facility	**$ 671,500**	**$ 671,500**	$ 421,200	$ 421,200
Senior notes	**$ 671,800**	**$ 773,578**	$ 673,000	$ 761,372
Derivative instruments, net	**$ 704,830**	**$ 704,830**	$ 160,452	$ 160,452

The carrying values of cash and cash equivalents, accounts receivable, accounts payable, other current assets and current liabilities on the condensed 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 4.6% at December 31, 2011 and 5.2% at December 31, 2010. The carrying values of the borrowings under the Company's unsecured revolving credit facility at December 31, 2011 and 2010 approximate fair value.

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.

Pursuant to GAAP, 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 internal discounted cash flow calculations using the NYMEX futures index. The Company's Level 3 fair value measurements include costless-collars and basis swaps. The Company's costless-collars 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 internal discounted cash flow calculations based upon forward commodity price curves.

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

	December 31, 2011			
	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	$ —	$ 534,560	$ 182,783	$ 717,343
Derivative liabilities	—	(11,849)	(664)	(12,513)
Total	$ —	$ 522,711	$ 182,119	$ 704,830

	December 31, 2010			
	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	$ —	$ 86,883	$ 121,442	$ 208,325
Derivative liabilities	—	(24,108)	(23,765)	(47,873)
Total	$ —	$ 62,775	$ 97,677	$ 160,452

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, 2011 and 2010. Level 3 instruments presented in the table consist of net derivatives valued using pricing models incorporating assumptions that, in the Company's judgment, reflect the assumptions a marketplace participant would have used at December 31, 2011 and at December 31, 2010.

Total net gains and losses for Level 3 derivatives for the years ended December 31, 2011 and 2010 are provided below:

	For the years ended December 31, 2011	2010
	(in thousands)	
Balance at beginning of period	$ 97,677	$ 24,720
Total gains or losses (realized/unrealized):		
Included in earnings	67,998	68,111
Included in other comprehensive income	79,215	63,522
Purchases, issuances and settlements		
Purchases	—	—
Issuances	—	—
Settlements	(62,913)	(58,676)
Transfers into/out of Level 3	142	—
Balance at end of period	$ 182,119	$ 97,677
Change in unrealized gain (loss) included in earnings relating to derivatives still held as of December 31	$ 5,085	$ 9,435

(7) DEBT

The components of debt as of December 31, 2011 and 2010 consisted of the following:

	2011	2010
	(in thousands)	
Short-term debt:		
7.15% Senior Notes due 2018	**$ 1,200**	$ 1,200
Total short-term debt	**1,200**	1,200
Long-term debt:		
Variable rate (2.276% at December 31, 2011 and 0.887% at December 31, 2010) unsecured revolving credit facility, expires February 2016	**671,500**	421,200
7.5% Senior Notes due 2018	**600,000**	600,000
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	**30,600**	31,800
	1,342,100	1,093,000
Total debt	**$ 1,343,300**	$ 1,094,200

The following is a summary of scheduled long-term debt maturities by year as of December 31, 2011 (in thousands):

2012	$ 1,200
2013	1,200
2014	1,200
2015	1,200
2016	672,700
Thereafter	665,800
	$ 1,343,300

Issuance of Senior Notes and Subsidiary Guarantees

In January 2008, the Company completed an offering of $600 million Senior Notes with a coupon rate of 7.5% (“7.5% Senior Notes”), a maturity in February 2018 and semi-annual interest payments. Upon a “change of control,” as defined in the indenture, holders have the option to require the Company to purchase all or any portion of the notes at a purchase price equal to 101% of the principal amount plus accrued and unpaid interest before the change of control date.

The indentures governing the Company's senior notes contain covenants that, among other things, restrict the ability of the Company and/or its subsidiaries' ability to incur liens, to engage in sale and leaseback transactions and to merge, consolidate or sell assets. All of the Company's senior notes are currently guaranteed by its subsidiaries, SEECO, Inc. ("SEECO"), Southwestern Energy Production Company ("SEPCO") and Southwestern Energy Services Company ("SES"). If no default or event of default has occurred and is continuing, these guarantees will 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 credit facility; and (iv) upon legal or covenant defeasance or other satisfaction of the obligations under the notes.

Please refer to Note 15, "Condensed Consolidating Financial Information" in this Form 10-K for additional information.

Credit Facility

In February 2011, the Company amended and restated its unsecured revolving credit facility, increasing the borrowing capacity to $1.5 billion and extending the maturity date to February 2016 ("Credit Facility"). The amount available under the Credit Facility may be increased to $2.0 billion at any time upon the Company's agreement with its existing or additional lenders. The Company had $671.5 and $421.2 million outstanding under its revolving credit facility at December 31, 2011 and December 31, 2010, respectively. The interest rate on the amended credit facility is calculated based upon our debt rating and is currently 200 basis points over the current London Interbank Offered Rate (LIBOR) and was 200 basis points over LIBOR at December 31, 2011. The Credit Facility is guaranteed by the Company's subsidiary, SEECO. The Credit Facility requires additional subsidiary guarantors if certain guaranty coverage levels are not satisfied. The revolving credit facility contains covenants which impose certain restrictions on the Company. Under the credit agreement, the Company may not issue total debt in excess of 60% of its total capital and must maintain a ratio of earnings before interest, taxes, depreciation and amortization (EBITDA) to interest expense of 3.5 or above. The terms of the Credit Facility also include covenants that restrict the ability of the Company and its material subsidiaries to merge, consolidate or sell all or substantially all of their assets, restrict the ability of the Company and its subsidiaries to incur liens and restrict the ability of the Company's subsidiaries to incur indebtedness. At December 31, 2011, the Company's capital structure consisted of 25% debt and 75% equity and it was in compliance with the covenants of its debt agreements. While 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.

Interest Payments

Total cash interest payments made by the Company were $64.8 million in 2011, $57.0 million in 2010 and $56.7 million in 2009.

(8) COMMITMENTS AND CONTINGENCIES

Operating Commitments and Contingencies

The Company has commitments to third parties for demand transportation charges. At December 31, 2011, future payments under non-cancelable demand charges are approximately $212.2 million in 2012, $218.8 million in 2013, $234.3 million in 2014, $233.7 million in 2015, $236.2 million in 2016 and $960.5 million thereafter.

Southwestern leases 14 drilling rigs and equipment for its E&P operations under leases that expire on January 1, 2015. The Company's current aggregate annual payment under the leases is approximately $19.4 million. The lease payments for the drilling rigs and 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 rig day-rate charges.

The Company leases compressors, aircraft, vehicles, office space and equipment under non-cancelable operating leases expiring through 2019. At December 31, 2011, future minimum payments under these non-cancelable leases accounted for as operating leases are approximately $69.9 million in 2012, $65.0 million in 2013, $57.7 million in 2014, $33.5 million in 2015, $25.9 million in 2016 and $16.2 million thereafter. The Company also has commitments for compression services related to its Midstream Services and E&P segments. At December 31, 2011, future minimum payments under these non-cancelable agreements are approximately $42.1 million in 2012, $30.0 million in 2013, $15.7 million in 2014, $9.6 million in 2015, $8.0 million in 2016 and $1.7 million thereafter.

During 2011, SES entered into a number of short and long term firm transportation service and gathering 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 and expansions of the system are expected to be in-service by late 2012 and late 2013. In June 2011, SES entered into a long term agreement with Bluestone Gathering, a wholly owned subsidiary of DTE Energy Company, pursuant to which Bluestone Gathering will build and operate a natural gas gathering system in Susquehanna County, Pennsylvania and Broome County, New York, and provide gathering services to SES in support of a portion of our future Marcellus Shale natural gas production. The projected in-service date for the gathering system is expected to be during the third quarter of 2012. SES also executed firm transportation agreements with Tennessee Gas Pipeline Company ("TGP") that increase our ability to move its Marcellus Shale natural gas production in the short term to market as well as a precedent agreement for an expansion project with a projected in-service date of November 2013 pursuant to which SES has subscribed for 100,000 Dekatherm/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. TGP filed a certificate application for the project with the Federal Energy Regulatory Commission in late 2011. Pending regulatory approvals, construction would begin in 2013, with a November 1, 2013 in-service date.

We have provided certain guarantees of a portion of SES's obligations under these agreements. As of December 31, 2011, SES's obligations for demand and similar charges under the firm transportation agreements totaled approximately $2.1 billion and we currently have not recognized any guarantee obligations with respect to the firm transportation agreements and the gathering project and services.

On October 6, 2011, the Company's subsidiary, Southwestern Energy Production Company ("SEPCO"), entered into a 15-year agreement with a subsidiary of Boardwalk Pipeline Partners for the construction of a gathering system in Susquehanna and Lackawanna counties in Pennsylvania, which once constructed is expected to have a delivery capacity of 275,000 Dekatherm/day.

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 million Canadian dollars ("CAD") in the aggregate over a three year period. 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 CAD $44.5 million. 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, 2011 had invested CAD $28.5 million in New Brunswick. No liability has been recognized in connection with the promissory notes due to the Company's investments in New Brunswick as of December 31, 2011 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 reported results of operations of the Company.

Litigation

In February 2009, SEPCO was added as a defendant in a Third Amended Petition in the matter of Tovah Energy, LLC and Toby Berry-Helfand v. David Michael Grimes, et, al. In the Sixth Amended Petition, filed in July 2010, in the 273rd District Court in Shelby County, Texas (collectively, the "Sixth Petition"), plaintiff alleged that, in 2005, they 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, the plaintiff's allegations in the Sixth Petition included 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 15, 2005 and February 15, 2006. In the Sixth Petition, plaintiff sought actual damages of over $55 million as well as other remedies, including special damages and punitive damages of four times the amount of actual damages established at trial.

Immediately before the commencement of the trial in November 2010, plaintiff was permitted, over SEPCO's objections, to file a Seventh Amended Petition claiming actual damages of $46 million and also seeking the equitable remedy of disgorgement of all profits for the misappropriation of trade secrets and the breach of fiduciary duty claims. In December 2010, the jury found in favor of the plaintiff with respect to all of the statutory and common law claims and awarded $11.4 million in compensatory damages. The jury did not, however, award the plaintiff any special, punitive or other damages. In addition, the jury separately determined that SEPCO's profits for purposes of disgorgement were $381.5 million. This profit determination does not constitute a judgment or an award. The plaintiff's entitlement to disgorgement of profits as an equitable remedy will be determined by the judge and it is within the judge's discretion to award none, some or all the amount of profit to the plaintiff. On December 31, 2010, the plaintiff filed a motion to enter the judgment based on the jury's verdict. On February 11, 2011, SEPCO filed a motion for a judgment notwithstanding the verdict and a motion to disregard certain findings. On March 11, 2011, the plaintiff filed an amended motion for judgment and intervenor filed its motion for judgment seeking not only the monetary damages and the profits determined by the jury but also seeking, as a new remedy, a constructive trust for profits from 143 wells as well as future drilling and sales of properties in the prospect areas. A hearing on the post-verdict motions was held on March 14, 2011. At the suggestion of the judge, all parties voluntarily agreed to participate in non-binding mediation efforts. The mediation occurred on April 6, 2011 and was unsuccessful. On June 6, 2011, SEPCO received by mail a letter dated June 2, 2011 from the judge, in which he made certain rulings with respect to the post-verdict motions and responses filed by the parties. In his rulings, the judge denied SEPCO's motion for judgment, judgment notwithstanding the verdict and to disregard certain findings. Plaintiff's and intervenor's claim for a constructive trust was denied but the judge ruled that plaintiff and intervenor shall recover from SEPCO $11.4 million and a reasonable attorney's fee of 40% of the total damages awarded and are entitled to recover on their claim for disgorgement. The judge instructed that SEPCO calculate the profit on the designated wells for each respective period. SEPCO performed the calculation and provided it to the judge in June 2011. On July 5, 2011, plaintiff and intervenor filed a letter with the court raising objections to the accounting provided by SEPCO, to which SEPCO filed a response on July 11, 2011. On July 12, 2011, the judge sent a letter to the parties in which he ruled that after reviewing the parties' respective position letters, he was awarding $23.9 million in disgorgement damages in favor of the plaintiff and intervenor. In the July 12, 2011 letter, the judge instructed the plaintiff and intervenor to prepare a judgment for his approval prior to July 21, 2011 consistent with his findings in his June 2, 2011 letter and the disgorgement award. On August 24, 2011, a judgment was entered pursuant to which plaintiff and intervenor are 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. On September 23, 2011, SEPCO filed a motion for a new trial and on November 18, 2011 filed a notice of appeal. On November 30, 2011, the court approved SEPCO's supersedeas bond in the amount of $14.1 million, which stays execution on the judgment pending appeal. The bond covers the $11.4 million judgment for actual damages, plus $1.3 million in pre-judgment interest, $1.3 million in post-judgment interest (estimating two years for the duration of appeal), and court costs.

The Company believes that SEPCO has a number of legal grounds for appealing the judgment, all of which will be vigorously pursued. Based on the Company's understanding and judgment of the facts and merits of this case, including appellate defenses, and after considering the advice of counsel, the Company has determined that, although reasonably possible after exhaustion of all appeals, an adverse final outcome to this lawsuit is not probable. As such, the Company has not accrued any amounts with respect to this lawsuit. If the plaintiff and intervenor were to ultimately prevail in the appellate process, the Company currently estimates, based on the judgments to date, that SEPCO's potential liability would be up to $44.2 million, including interest and attorney's fees. The Company's assessment may change in the future due to occurrence of certain events, such as denied appeals, and such 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.

On February 20, 2012, the Company became aware that SEPCO was named as a defendant in the matter of Gery Muncey v. Southwestern Energy Production Company, et al filed in the District Court of San Augustine County in Texas on January 31, 2012. The plaintiff in this case is also the intervenor in the Tovah Energy matter described above and alleges various claims including fraud, misappropriation and breach of fiduciary duty that are purported as independent of the claims alleged in the Tovah Energy matter but arise from the substantially same circumstances involved in the Tovah Energy matter. The plaintiff is seeking value for various royalty and override ownership interests in wells drilled, disgorgement of profits and punitive damages. The Company has not accrued any amounts with respect to this lawsuit and cannot reasonably estimate the amount of any potential liability based on the Company's understanding and judgment of the facts and merits of this case.

In March 2010, the Company's subsidiary, SEECO, Inc., 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 described below, the Company believes the grand jury is investigating matters involving approximately 27 horizontal wells operated by SEECO in Arkansas, including whether appropriate leases or permits were obtained therefor and whether royalties and other production attributable to federal lands have been properly accounted for and paid. The Company believes it has fully complied with all requests related to the federal subpoena and delivered its affidavit to that effect. The Company and representatives of the Bureau of Land Management and the U.S. Attorney have had discussions since the production of the documents pursuant to the subpoena. In January 2011, the Company voluntarily produced additional materials informally requested by the government arising from these discussions. Although, to the Company's knowledge, no proceeding in this matter has been initiated against SEECO, the Company cannot predict whether or when one might be initiated. The Company intends to fully comply with any further requests and to cooperate with any related investigation. No assurance can be made as to the time or resources that will need to be devoted to this inquiry or the impact of the final outcome of the discussions or any related proceeding.

We are subject to various litigation, claims and proceedings that have arisen in the ordinary course of business. Management believes, individually or in aggregate, such litigation, claims and proceedings will not have a material adverse impact on our financial position or our results of operations but these matters are subject to inherent uncertainties and 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 our financial position, results of operations or cash flows for the period in which the effect becomes reasonably estimable. We accrue 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.

(9) INCOME TAXES

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

	2011	2010	2009
		(in thousands)	
Current:			
Federal	**$ 3,378**	$ 10,421	$ (65,309)
State	**820**	1,518	340
	4,198	11,939	(64,969)
Deferred:			
Federal	**345,922**	319,279	48,308
State	**60,941**	59,982	298
Foreign	**2,160**	459	—
	409,023	379,720	48,606
Provision (benefit) for income taxes	**$ 413,221**	$ 391,659	$ (16,363)

The provision for income taxes was an effective rate of 39.3% in 2011, 39.3% in 2010 and 31.5% in 2009. 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:

	2011	2010	2009
		(in thousands)	
Expected provision (benefit) at federal statutory rate	**$ 367,854**	$ 348,632	$ (18,205)
Increase (decrease) resulting from:			
State income taxes, net of federal income tax effect	**40,145**	39,975	415
Nondeductible expenses	**1,244**	660	1,497
Other	**3,978**	2,392	(70)
Provision (benefit) for income taxes	**$ 413,221**	$ 391,659	$ (16,363)

The components of the Company's net deferred tax liability as of December 31, 2011 and 2010 were as follows:

	2011	2010
	(in thousands)	
Deferred tax liabilities:		
Differences between book and tax basis of property	**$ 1,916,619**	$ 1,411,240
Cash flow hedges	**276,063**	61,394
Other	**15,755**	14,122
	2,208,437	1,486,756
Deferred tax assets:		
Accrued compensation	**30,316**	16,279
Alternative minimum tax credit carryforward	**73,516**	70,138
Stored natural gas	**9,053**	7,145
Accrued pension costs	**3,982**	6,227
Asset retirement obligations	**13,188**	10,848
Net operating loss carryforward	**287,830**	192,086
Other	**9,591**	9,652
	427,476	312,375
Net deferred tax liability	**$ 1,780,961**	$ 1,174,381

The net deferred tax liability at December 31, 2011 was comprised of net long-term deferred income tax liabilities of $1,586.8 million in addition to a net current deferred income tax liability of $194.2 million. The net deferred tax liability at December 31, 2010 was comprised of net long-term deferred income tax liabilities of $1,130.3 million, in addition to a net current deferred income tax liability of $44.1 million. In 2011, the Company paid $0.8 million in state income taxes and paid $3.4 million in alternative minimum taxes. In 2010, the Company paid $0.4 million in state income taxes and paid $14.0 million in alternative minimum taxes. The Company's net operating loss carryforward at December 31, 2011 was $878.2 million and has expiration dates of 2027 through 2031. The Company also had an alternative minimum tax credit carryforward of $73.5 million and a statutory depletion carryforward of $13.0 million at December 31, 2011.

Deferred tax assets relating to tax benefits of employee stock option grants have been reduced to reflect exercises in 2011. 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 2011 due to net operating loss carryforwards, these "windfall" tax benefits are not reflected in our net operating losses in deferred tax assets for 2011. Windfalls included in net operating loss carryforwards but not reflected in deferred tax assets for 2011 were $110.3 million. The Company utilized a portion of its net operating loss carryforward in 2010 based on its federal income tax return filing. Therefore, an additional tax return benefit associated with the windfall was recognized in 2011.

As of December 31, 2011, the Company has no unrecognized tax benefits. The income tax years 2008 and 2009 have been audited by the Internal Revenue Service resulting in no changes to the Company's taxes. The income tax years 2009 to 2011 remain open to examination by the major taxing jurisdictions to which the Company is subject, except for the 2009 federal tax return for which the examination is complete.

The Company has an income tax net operating loss carryforward related to its Canadian operations of $11.0 million, and has expiration dates of 2030 through 2031. 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 recorded a valuation allowance of $2.0 million, as of December 31, 2011, to reflect that it is more likely than not that the deferred tax asset will not be recognized. The Company recorded a valuation allowance of $0.5 million in 2010. The amount of the deferred tax asset considered realizable could be adjusted if estimates of future taxable income during the carryforward period are increased.

(10) ASSET RETIREMENT OBLIGATIONS

The following table summarizes the Company's 2011 and 2010 activity related to asset retirement obligations:

	2011	2010
	(in thousands)	
Asset retirement obligation at January 1	**$ 27,786**	$ 22,972
Accretion of discount	**1,361**	1,095
Obligations incurred	**4,304**	6,926
Obligations settled/removed	**(883)**	(477)
Revisions of estimates	**5,125**	(2,730)
Asset retirement obligation at December 31	**$ 37,693**	$ 27,786
Current liability	**1,539**	1,829
Long-term liability	**36,154**	25,957
Asset retirement obligation at December 31	**$ 37,693**	$ 27,786

(11) 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 $1.9 million, $0.9 million and $0.8 million of contribution expense in 2011, 2010 and 2009, respectively. Additionally, the Company capitalized $3.8 million, $4.2 million and $3.3 million of contributions in 2011, 2010 and 2009, 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, 2011 and 2010:

	Pension Benefits		Other Postretirement Benefits	
	2011	2010	**2011**	2010
	(in thousands)			
Change in benefit obligations:				
Benefit obligation at January 1	**$ 67,933**	$ 56,736	**$ 4,955**	$ 3,271
Service cost	**9,323**	7,096	**1,354**	1,089
Interest cost	**3,671**	3,249	**252**	195
Participant contributions	**—**	—	**19**	15
Actuarial loss	**6,967**	6,311	**302**	462
Benefits paid	**(6,156)**	(5,029)	**(89)**	(77)
Plan amendments	**—**	168	**—**	—
Settlements	**—**	(598)	**—**	—
Benefit obligation at December 31	**$ 81,738**	$ 67,933	**$ 6,793**	$ 4,955

	Pension Benefits		Other Postretirement Benefits	
	2011	2010	**2011**	2010
	(in thousands)			
Change in plan assets:				
Fair value of plan assets at January 1	**$ 56,949**	$ 46,689	**$ —**	$ —
Actual return/(loss) on plan assets	**4,717**	6,276	**—**	—
Employer contributions	**12,513**	9,667	**70**	62
Participant contributions	**—**	—	**19**	15
Benefits paid	**(6,156)**	(5,029)	**(89)**	(77)
Settlements	**—**	(654)	**—**	—
Fair value of plan assets at December 31	**$ 68,023**	$ 56,949	**$ —**	$ —
Funded status of plans at December 31	**$ (13,715)**	$ (10,984)	**$ (6,793)**	$ (4,955)

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 loss of $5.4 million ($3.3 million after tax) for the year ended December 31, 2011 and a loss of $2.4 million ($1.2 million after tax) for the year ended December 31, 2010. The change in accumulated other comprehensive income related to the other postretirement benefit plan was a loss of $0.2 million ($0.1 million after tax) for the year ended December 31, 2011 and was a loss of $0.4 million ($0.2 million after tax) for the year ended December 31, 2010. Included in accumulated other comprehensive income at December 31, 2011 and 2010 was a $26.2 million loss ($15.9 million net of tax) and a $20.5 million loss ($12.5 million net of tax), respectively, related to the Company's pension and other postretirement benefit plans.

The amounts in accumulated other comprehensive income that are expected to be recognized as components of net periodic benefit cost during 2012 are $0.3 million for prior service costs, $1.2 million net loss and $0.1 million for transition obligation costs.

The pension plans' projected benefit obligation, accumulated benefit obligation and fair value of plan assets as of December 31, 2011 and 2010 are as follows:

	2011	2010
	(in thousands)	
Projected benefit obligation	**$ 81,738**	$ 67,933
Accumulated benefit obligation	**$ 77,317**	$ 63,665
Fair value of plan assets	**$ 68,023**	$ 56,949

Pension and other postretirement benefit costs include the following components for 2011, 2010 and 2009:

	Pension Benefits			Other Postretirement Benefits		
	2011	2010	2009	**2011**	2010	2009
	(in thousands)					
Service cost	**$ 9,323**	$ 7,096	$ 5,148	**$ 1,354**	$ 1,089	$ 696
Interest cost	**3,671**	3,249	2,874	**252**	195	136
Expected return on plan assets	**(4,398)**	(3,503)	(2,809)	**—**	—	—
Amortization of transition obligation	**—**	—	—	**64**	65	65
Amortization of prior service cost	**344**	346	334	**14**	14	14
Amortization of net loss	**856**	806	846	**11**	21	7
Net periodic benefit cost	**9,796**	7,994	6,393	**1,695**	1,384	918
Settlements and curtailments	**—**	223	—	**—**	—	—
Total benefit cost	**$ 9,796**	$ 8,217	$ 6,393	**$ 1,695**	$ 1,384	$ 918

Amounts recognized in other comprehensive income for the year ended December 31, 2011 were as follows:

	Pension Benefits	Other Postretirement Benefits
	(in thousands)	
Net actuarial loss arising during the year	$ (6,648)	$ (302)
Amortization of transition obligation	—	64
Amortization of prior service cost	344	14
Amortization of net loss	856	11
Tax effect	2,210	88
	$ (3,238)	$ (125)

The weighted average assumptions used in the measurement of the Company's benefit obligations at December 31, 2011 and 2010 are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2011	2010	**2011**	2010
Discount rate	**5.00%**	5.50%	**5.00%**	5.50%
Rate of compensation increase	**4.50%**	4.50%	**n/a**	n/a

The weighted average assumptions used in the measurement of the Company's net periodic benefit cost for 2011, 2010 and 2009 are as follows:

	Pension Benefits			Other Postretirement Benefits		
	2011	2010	2009	**2011**	2010	2009
Discount rate	**5.50%**	5.75%	6.00%	**5.50%**	5.75%	6.00%
Expected return on plan assets	**7.50%**	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 2011 and 2010:

	2011	2010
Health care cost trend assumed for next year	**9%**	9%
Rate to which the cost trend is assumed to decline	**5%**	5%
Year that the rate reaches the ultimate trend rate	**2031**	2030

Assumed health care cost trend rates have a significant effect on the amounts reported 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	$ 235	$ (196)
Effect on postretirement benefit obligation	$ 940	$ (788)

Pension Payments and Asset Management

In 2011, 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 $12.7 million to its pension plans and $0.2 million to its other postretirement benefit plan in 2012. 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)	
2012	$ 3,894	$ 150
2013	$ 4,808	$ 217
2014	$ 6,310	$ 322
2015	$ 6,183	$ 443
2016	$ 7,908	$ 657
Years 2017-2021	$ 54,647	$ 5,321

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 Retirement Committee of the Company's Board of Directors ("Retirement Committee") administers the Company's pension plan assets. The Retirement 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 Retirement Committee and the actual weighted-average asset allocation of the Company's pension plan at December 31, 2011, by asset category. The asset allocation targets are subject to change and the Retirement 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
Equity securities:		
U.S. large cap growth equity	6%	6%
U.S. large cap value equity	6%	5%
U.S. large cap core equity	15%	16%
U.S. small cap equity	3%	3%
Non-U.S. equity	25%	25%
Emerging markets equity	5%	5%
Fixed income and cash and cash equivalents	40%	40%
Total	100%	100%

Utilizing GAAP's fair value hierarchy, the Company's fair value measurement of pension plan assets at December 31, 2011 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)	$ 3,792	$ 3,792	$ —	$ —
U.S. large cap value equity (2)	3,689	3,689	—	—
U.S. large cap core equity (3)	10,849	—	10,849	—
U.S. small cap equity (4)	2,201	2,201	—	—
Non-U.S. equity (5)	16,719	16,719	—	—
Emerging markets equity (6)	3,377	—	3,377	—
Fixed income (7)	25,192	—	25,192	—
Cash and cash equivalents	2,204	2,204	—	—
Total	$ 68,023	$ 28,605	$ 39,418	$ —

(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.

Utilizing GAAP's fair value hierarchy, the Company's fair value measurement of pension plan assets at December 31, 2010 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:				
Large cap growth equity (1)	$ 5,937	$ 5,937	$ —	$ —
Large cap value equity (2)	5,838	5,838	—	—
Large cap core equity (3)	8,062	8,062	—	—
Small cap equity (4)	6,662	6,662	—	—
International equity (5)	8,333	8,333	—	—
Fixed income (6)	18,539	18,539	—	—
Cash and cash equivalents	3,578	3,578	—	—
Total	$ 56,949	$ 56,949	$ —	$ —

(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) Mutual fund that seeks to replicate the Standards & Poor's 500 index by investing at least 80% of assets in S&P 500 stocks.
(4) Mutual fund that seeks to invest in a diversified portfolio of stocks with small market capitalizations.
(5) Mutual fund that seeks to invest in a diversified portfolio of stocks and fixed income securities with at least 80% of its investments in securities issued in Europe or the Pacific Basin.
(6) Mutual fund that seeks to invest in a diversified portfolio of bonds with investment grade quality United States ("U.S.") dollar-denominated securities of U.S. issuers.

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.

(12) STOCK-BASED COMPENSATION

The Southwestern Energy Company 2004 Stock Incentive Plan (2004 Plan) was adopted in February 2004 and approved by stockholders in May 2004. The 2004 Plan provides for the compensation of officers, key employees and eligible non-employee directors of the Company and its subsidiaries. The 2004 Plan replaced 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 2004 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 16,800,000 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 2004 Plan.

As initially adopted, the 2000 Plan provided for the grant of options, stock appreciation rights, shares of phantom stock, and shares of restricted stock to employees, officers and directors that in the aggregate did not exceed 1,250,000 shares of common stock. As initially adopted, 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 300,000 shares 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 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 8, 2005 immediately vest upon death, disability or retirement (subject to a minimum of five years of service).

Stock Options

The Company recorded the following compensation costs related to stock options for the years ended December 31, 2011, 2010 and 2009:

	2011	2010 (in thousands)	2009
Stock-based compensation cost related to stock options – general and administrative expense	$ 4,959	$ 4,706	$ 5,108
Stock-based compensation cost related to stock options – capitalized	$ 3,365	$ 2,679	$ 2,124

The Company also recorded a deferred tax benefit of $1.7 million related to stock options in 2011, compared to deferred tax benefits of $1.7 million in 2010 and $1.4 million in 2009. A total of $20.7 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	**2011**	2010	2009
Risk-free interest rate	**0.9%**	2.0%	2.2%
Expected dividend yield	**—**	—	—
Expected volatility	**58.1%**	60.1%	61.6%
Expected term	**5 years**	5 years	5 years

The following tables summarize stock option activity for the years 2011, 2010 and 2009 and provide information for options outstanding at December 31 of such years:

	2011		2010		2009	
	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	**4,769,122**	**$ 16.13**	5,649,233	$ 11.59	7,396,537	$ 7.44
Granted	**853,478**	**36.64**	446,895	37.05	412,515	39.83
Exercised	**(850,659)**	**7.54**	(1,293,046)	3.01	(2,152,819)	2.67
Forfeited or expired	**(30,209)**	**35.46**	(33,960)	35.26	(7,000)	31.21
Options outstanding at December 31	**4,741,732**	**$ 21.24**	4,769,122	$ 16.13	5,649,233	$ 11.59

Range of Exercise Prices	Options Outstanding: Options Outstanding at December 31, 2011	Options Outstanding: Weighted Average Exercise Price	Options Outstanding: Weighted Average Remaining Contractual Life (Years)	Options Outstanding: Aggregate Intrinsic Value (in thousands)	Options Exercisable: Options Exercisable at December 31, 2011	Options Exercisable: Weighted Average Exercise Price	Options Exercisable: Weighted Average Remaining Contractual Life (Years)	Options Exercisable: Aggregate Intrinsic Value (in thousands)
$1.43 - $3.10	1,727,398	$ 2.10	1.5		1,727,398	$ 2.10	1.5	
$3.11 - $30.00	862,650	22.19	2.1		856,544	22.14	2.1	
$30.01 - $36.00	606,133	31.54	4.4		490,190	31.11	4.0	
$36.01 - $40.00	1,130,705	36.77	6.5		153,086	36.86	5.5	
$40.01 - $51.47	414,846	41.60	5.0		254,850	41.50	4.8	
	4,741,732	$ 21.24	3.5	$ 60,505	3,482,068	$ 15.53	2.4	$ 60,484

The weighted-average grant-date fair value of options granted during the years 2011, 2010 and 2009 was $18.17, $19.40 and $21.35, respectively. The total intrinsic value of options exercised during 2011, 2010 and 2009 was $27.0 million, $41.4 million and $87.6 million, respectively.

Restricted Stock

The Company recorded the following compensation costs related to restricted stock grants for the years ended December 31, 2011, 2010 and 2009:

	2011	2010 (in thousands)	2009
Stock-based compensation cost related to restricted stock grants – general and administrative expense	$ 5,591	$ 5,114	$ 5,069
Stock-based compensation cost related to restricted stock grants – capitalized	$ 5,162	$ 4,107	$ 3,767

The Company also recorded a deferred tax liability of $2.1 million related to restricted stock for the year ended December 31, 2011, compared to deferred tax liabilities of $1.4 million for 2010 and $0.7 million for 2009. As of December 31, 2011, there was $34.0 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 3.2 years.

The following table summarizes the restricted stock activity for the years 2011, 2010 and 2009 and provides information for restricted stock outstanding at December 31 of such years:

	2011		2010		2009	
	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	**834,058**	**$ 36.24**	794,529	$ 33.70	843,430	$ 27.66
Granted	**532,754**	**36.41**	390,415	36.46	319,950	39.03
Vested	**(294,358)**	**34.90**	(319,894)	30.45	(359,247)	24.37
Forfeited	**(52,717)**	**36.45**	(30,992)	33.54	(9,604)	29.47
Unvested shares at December 31	**1,019,737**	**$ 36.71**	834,058	$ 36.24	794,529	$ 33.70

The fair values of the grants were $19.4 million for 2011, $14.2 million for 2010 and $12.5 million for 2009. The total fair value of shares vested were $10.9 million for 2011, $9.7 million for 2010 and $14.9 million for 2009.

(13) 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 crude 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)				
2011					
Revenues from external customers	**$ 2,088,763**		**$ 864,096**	**$ 47**	**$ 2,952,906**
Intersegment revenues	**11,725**		**1,995,423**	**3,221**	**2,010,369**
Operating income	**825,138**		**247,952**	**1,711**	**1,074,801**
Other income, net(1)	**328**		**(91)**	**27**	**264**
Depreciation, depletion and amortization expense	**666,125**		**37,261**	**1,125**	**704,511**
Interest expense(1)	**9,026**		**15,049**	**—**	**24,075**
Provision for income taxes(1)	**322,714**		**90,221**	**286**	**413,221**
Assets	**6,547,117**	**(2)**	**1,119,861**	**235,919**	**7,902,897**
Capital investments(3)	**1,977,493**		**160,776**	**68,905**	**2,207,174**
2010					
Revenues from external customers	$ 1,871,835		$ 738,828	$ —	$ 2,610,663
Intersegment revenues	18,609		1,715,012	984	1,734,605
Operating income	829,462		191,566	200	1,021,228
Other income, net(1)	235		179	13	427
Depreciation, depletion and amortization expense	561,018		28,765	549	590,332
Interest expense(1)	7,888		18,275	—	26,163
Provision for income taxes(1)	323,748		67,834	77	391,659
Assets	4,849,478	(2)	1,016,563	151,422	6,017,463
Capital investments(3)	1,775,518		271,316	73,231	2,120,065
2009					
Revenues from external customers	$ 1,582,596		$ 562,944	$ 239	$ 2,145,779
Intersegment revenues	10,635		1,040,388	448	1,051,471
Operating income (loss)	(157,725)		122,620	139	(34,966)
Other income, net(1)	1,406		34	9	1,449
Depreciation, depletion and amortization expense	474,014		19,213	431	493,658
Impairment of natural gas and oil properties	907,812		—	—	907,812
Interest expense(1)	15,237		3,401	—	18,638
Provision (benefit) for income taxes(1)	(61,725)		45,303	59	(16,363)
Assets	3,904,739	(2)	767,346	98,165	4,770,250
Capital investments(3)	1,565,450		214,208	29,459	1,809,117

(1) Interest income, interest expense and the provision (benefit) for income taxes by segment are an allocation of corporate amounts as cash equivalents, debt and income tax expense allocated as they are incurred at the corporate level.

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

(3) Capital investments include an increase of $4.3 million for 2011, an increase of $14.4 million for 2010 and an increase of $12.2 million for 2009 related to the change in accrued expenditures between years.

Included in intersegment revenues of the Midstream Services segment are $1.7 billion, $1.5 billion and $0.9 billion for 2011, 2010 and 2009, 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 2011 and 2010, capital investments within the E&P segment include $18.7 million and $10.7 million, respectively, related to the Company's activities in Canada. At December 31, 2011, assets include $28.4 million and at December 31, 2010, assets include $11.5 million related to the Company's activities in Canada.

(14) QUARTERLY RESULTS (UNAUDITED)

The following is a summary of the quarterly results of operations for the years ended December 31, 2011 and 2010:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
	(in thousands, except per share amounts)			
	2011			
Operating revenues	**$ 676,335**	**$ 765,166**	**$ 767,255**	**$ 744,150**
Operating income	**232,651**	**282,542**	**295,718**	**263,890**
Net income	**136,609**	**167,454**	**175,173**	**158,533**
Net income attributable to Southwestern Energy	**136,609**	**167,454**	**175,173**	**158,533**
Earnings per share attributable to Southwestern Energy stockholders – Basic	**0.39**	**0.48**	**0.50**	**0.47**
Earnings per share attributable to Southwestern Energy stockholders – Diluted	**0.39**	**0.48**	**0.50**	**0.45**
	2010			
Operating revenues	$ 668,117	$ 589,943	$ 682,172	$ 670,431
Operating income (loss)	288,090	206,317	270,136	256,685
Net income (loss)	171,768	122,009	160,638	149,418
Net income (loss) attributable to Southwestern Energy	171,797	122,069	160,741	149,511
Earnings per share attributable to Southwestern Energy stockholders – Basic	0.50	0.35	0.47	0.43
Earnings per share attributable to Southwestern Energy stockholders – Diluted	0.49	0.35	0.46	0.43

(15) CONDENSED CONSOLIDATING FINANCIAL INFORMATION

The Company is providing condensed consolidating financial information for SEECO, SEPCO and SES, its subsidiaries that are currently guarantors of the Company's registered public debt, and for its other subsidiaries that are not guarantors of such debt. These wholly owned subsidiary guarantors have jointly and severally, fully and unconditionally guaranteed the Company's 7.35% Senior Notes and 7.125% Senior Notes. The subsidiary guarantees (i) rank equally in right of payment with all of the existing and future senior debt of the subsidiary guarantors; (ii) rank senior to all of the existing and future subordinated debt of the subsidiary guarantors; (iii) are 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) are 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 has occurred and is continuing, these guarantees will 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 credit facility; and (iv) upon legal or covenant defeasance or other satisfaction of the obligations under the notes.

The Company has not presented separate financial and narrative information for each of the 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 guarantor and non-guarantor subsidiaries.

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS

	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
			(in thousands)		
Year ended December 31, 2011:					
Operating revenues	$ —	$ 2,803,385	$ 411,998	$ (262,477)	$ 2,952,906
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	—	851,680	223,121	—	1,074,801
Other income, net	—	306	(42)	—	264
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
Year ended December 31, 2010:					
Operating revenues	$ —	$ 2,488,105	$ 318,232	$ (195,674)	$ 2,610,663
Operating costs and expenses:					
Gas purchases	—	612,745	—	(1,584)	611,161
Operating expenses	—	293,713	91,164	(193,106)	191,771
General and administrative expenses	—	127,022	19,525	(984)	145,563
Depreciation, depletion and amortization	—	559,845	30,487	—	590,332
Taxes, other than income taxes	—	44,200	6,408	—	50,608
Total operating costs and expenses	—	1,637,525	147,584	(195,674)	1,589,435
Operating income	—	850,580	170,648	—	1,021,228
Other income, net	—	242	185	—	427
Equity in earnings of subsidiaries	604,118	—	—	(604,118)	—
Interest expense	—	10,777	15,386	—	26,163
Income (loss) before income taxes	604,118	840,045	155,447	(604,118)	995,492
Provision for income taxes	—	330,879	60,780	—	391,659
Net income (loss)	604,118	509,166	94,667	(604,118)	603,833
Less: Net loss attributable to noncontrolling interest	—	(285)	—	—	(285)
Net income (loss) attributable to Southwestern Energy	$ 604,118	$ 509,451	$ 94,667	$ (604,118)	$ 604,118
Year ended December 31, 2009:					
Operating revenues	$ —	$ 2,071,746	$ 207,672	$ (133,639)	$ 2,145,779
Operating costs and expenses:					
Gas purchases	—	483,922	—	(1,086)	482,836
Operating expenses	—	201,964	66,682	(132,105)	136,541
General and administrative expenses	—	109,870	13,196	(448)	122,618
Depreciation, depletion and amortization	—	472,757	20,901	—	493,658
Impairment of natural gas & oil properties	—	907,812	—	—	907,812
Taxes, other than income taxes	—	33,935	3,345	—	37,280
Total operating costs and expenses	—	2,210,260	104,124	(133,639)	2,180,745
Operating income (loss)	—	(138,514)	103,548	—	(34,966)
Other income, net	—	1,388	61	—	1,449
Equity in earnings of subsidiaries	(35,650)	—	—	35,650	—
Interest expense	—	12,760	5,878	—	18,638
Income (loss) before income taxes	(35,650)	(149,886)	97,731	35,650	(52,155)
Provision (benefit) for income taxes	—	(53,549)	37,186	—	(16,363)
Net income (loss)	(35,650)	(96,337)	60,545	35,650	(35,792)
Less: Net loss attributable to noncontrolling interest	—	(142)	—	—	(142)
Net income (loss) attributable to Southwestern Energy	$ (35,650)	$ (96,195)	$ 60,545	$ 35,650	$ (35,650)

CONDENSED CONSOLIDATING BALANCE SHEETS

	Parent	Guarantors	Non- Guarantors	Eliminations	Consolidated
			(in thousands)		
December 31, 2011:					
ASSETS					
Cash and cash equivalents	$ 14,711	$ —	$ 916	$ —	$ 15,627
Accounts receivable	2,914	309,038	29,963	—	341,915
Inventories	—	45,260	974	—	46,234
Other current assets	6,087	563,635	4,780	—	574,502
Total current assets	23,712	917,933	36,633	—	978,278
Intercompany receivables	2,053,132	53	23,517	(2,076,702)	—
Property and equipment	180,300	9,731,944	1,148,575	—	11,060,819
Less: Accumulated depreciation, depletion and amortization	57,254	4,220,205	137,880	—	4,415,339
	123,046	5,511,739	1,010,695	—	6,645,480
Investments in subsidiaries (equity method)	3,256,195	—	—	(3,256,195)	—
Other assets	28,641	227,152	23,346	—	279,139
Total assets	$ 5,484,726	$ 6,656,877	$ 1,094,191	$ (5,332,897)	$ 7,902,897
LIABILITIES AND EQUITY					
Accounts and notes payable	$ 206,541	$ 332,710	$ 37,276	$ —	$ 576,527
Other current liabilities	4,712	301,170	2,504	—	308,386
Total current liabilities	211,253	633,880	39,780	—	884,913
Intercompany payables	—	1,628,750	447,952	(2,076,702)	—
Long-term debt	1,342,100	—	—	—	1,342,100
Deferred income taxes	(97,045)	1,442,576	241,267	—	1,586,798
Other liabilities	59,114	54,826	5,842	—	119,782
Total liabilities	1,515,422	3,760,032	734,841	(2,076,702)	3,933,593
Commitments and contingencies					
Total equity	3,969,304	2,896,845	359,350	(3,256,195)	3,969,304
Total liabilities and equity	$ 5,484,726	$ 6,656,877	$ 1,094,191	$ (5,332,897)	$ 7,902,897

CONDENSED CONSOLIDATING BALANCE SHEETS

	Parent	Guarantors	Non- Guarantors	Eliminations	Consolidated
			(in thousands)		
December 31, 2010:					
ASSETS					
Cash and cash equivalents	$ 8,381	$ 7,631	$ 43	$ —	$ 16,055
Accounts receivable	382	331,154	20,037	—	351,573
Inventories	—	34,263	835	—	35,098
Other current assets	5,015	171,060	2,092	—	178,167
Total current assets	13,778	544,108	23,007	—	580,893
Intercompany receivables	1,820,857	131	18,724	(1,839,712)	—
Investments	—	11,103	(11,102)	(1)	—
Property and equipment	124,823	7,871,279	984,783	—	8,980,885
Less: Accumulated depreciation, depletion and amortization	52,256	3,526,010	104,422	—	3,682,688
	72,567	4,345,269	880,361	—	5,298,197
Investments in subsidiaries (equity method)	2,253,871	—	—	(2,253,871)	—
Other assets	18,918	92,747	26,708	—	138,373
Total assets	$ 4,179,991	$ 4,993,358	$ 937,698	$ (4,093,584)	$ 6,017,463
LIABILITIES AND EQUITY					
Accounts and notes payable	$ 175,476	$ 336,411	$ 33,208	$ —	$ 545,095
Other current liabilities	3,288	142,839	2,761	—	148,888
Total current liabilities	178,764	479,250	35,969	—	693,983
Intercompany payable	—	1,317,696	522,017	(1,839,713)	—
Long-term debt	1,093,000	—	—	—	1,093,000
Deferred income taxes	(98,206)	1,066,166	162,332	—	1,130,292
Other liabilities	41,557	89,986	3,769	—	135,312
Total liabilities	1,215,115	2,953,098	724,087	(1,839,713)	3,052,587
Commitments and contingencies					
Total equity	2,964,876	2,040,260	213,611	(2,253,871)	2,964,876
Total liabilities and equity	$ 4,179,991	$ 4,993,358	$ 937,698	$ (4,093,584)	$ 6,017,463

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
			(in thousands)		
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 year	$ 14,711	$ —	$ 916	$ —	$ 15,627
Year ended December 31, 2010:					
Net cash provided by operating activities	$ 25,865	$ 1,368,248	$ 248,472	$ —	$ 1,642,585
Investing activities:					
Capital investments	(46,062)	(1,718,847)	(308,265)	—	(2,073,174)
Proceeds from sale of property and equipment	—	348,274	1,953	—	350,227
Transfers to restricted cash	(356,035)	—	—	—	(356,035)
Transfers from restricted cash	356,035	—	—	—	356,035
Other	11,864	(22,719)	8,171	—	(2,684)
Net cash used in investing activities	(34,198)	(1,393,292)	(298,141)	—	(1,725,631)
Financing activities:					
Intercompany activities	(76,904)	26,899	50,005	—	—
Payments on current portion of long-term debt	(1,200)	—	—	—	(1,200)
Payments on revolving long-term debt	(2,958,100)	—	—	—	(2,958,100)
Borrowings under revolving long-term debt	3,054,800	—	—	—	3,054,800
Other	(9,260)	—	—	—	(9,260)
Net cash provided by financing activities	9,336	26,899	50,005	—	86,240
Effect of exchange rate changes on cash	—	—	(323)	—	(323)
Increase in cash and cash equivalents	1,003	1,855	13	—	2,871
Cash and cash equivalents at beginning of year	7,378	5,776	30	—	13,184
Cash and cash equivalents at end of year	$ 8,381	$ 7,631	$ 43	$ —	$ 16,055
Year ended December 31, 2009:					
Net cash provided by operating activities	$ 58,212	$ 1,198,995	$ 102,169	$ —	$ 1,359,376
Investing activities:					
Capital investments	(17,075)	(1,517,990)	(245,100)	—	(1,780,165)
Proceeds from sale of property and equipment	—	763	55	—	818
Other	10,980	(29,238)	17,001	—	(1,257)
Net cash used in investing activities	(6,095)	(1,546,465)	(228,044)	—	(1,780,604)
Financing activities:					
Intercompany activities	(478,843)	353,246	125,597	—	—
Payments on current portion of long-term debt	(61,200)	—	—	—	(61,200)
Payments on revolving long-term debt	(1,371,700)	—	—	—	(1,371,700)
Borrowings under revolving long-term debt	1,696,200	—	—	—	1,696,200
Other	(25,165)	—	—	—	(25,165)
Net cash provided by (used in) financing activities	(240,708)	353,246	125,597	—	238,135
Increase (decrease) in cash and cash equivalents	(188,591)	5,776	(278)	—	(183,093)
Cash and cash equivalents at beginning of year	195,969	—	308	—	196,277
Cash and cash equivalents at end of year	$ 7,378	$ 5,776	$ 30	$ —	$ 13,184

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

None.

ITEM 9A. 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, 2011. There were no changes in our internal control over financial reporting during the three months ended December 31, 2011, 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 68 of this Form 10-K.

ITEM 9B. OTHER INFORMATION

There was no information required to be disclosed in a current report on Form 8-K during the fourth quarter of the fiscal year ended December 31, 2011, that was not reported on such form.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

EXECUTIVE OFFICERS OF THE REGISTRANT

Name	Officer Position	Age	Years Served as Officer
Steven L. Mueller	President and Chief Executive Officer	58	3
William J. Way	Executive Vice President & Chief Operating Officer	52	—
Greg D. Kerley	Executive Vice President and Chief Financial Officer	56	22
Mark K. Boling	Executive Vice President, General Counsel and Secretary	54	10
Gene A. Hammons[1]	President, Southwestern Midstream Services Company*	66	7

Mr. Mueller was appointed Chief Executive Officer in May 2009 and was subsequently 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. In December

[1] Mr. Hammons will be retiring from the Company after the first quarter of 2012.

* Position held with one or more subsidiaries of the Company

2008, CDX Gas, LLC voluntarily filed for bankruptcy. In 2009, CDX emerged from bankruptcy and resumed operations as Vitruvian Exploration LLC. 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, Belco Oil & Gas Company and The Houston Exploration Company. Mr. Mueller is the president of the Company's subsidiaries, Southwestern Field Services, LLC, DeSoto Sand, LLC, SWN International, LLC, Southwestern NGV Services, LLC and A.W. Realty Company. Mr. Mueller is also a director of the Company's subsidiaries, SWN Resources Canada, Inc., Certified Title Company and A.W. Realty Company.

Mr. Way joined the Company in 2011 as Executive Vice President and Chief Operating Officer of the Southwestern Energy Company. He is also Executive Vice President of the Company's subsidiaries, Southwestern Energy Production Company, SEECO, Inc., Diamond "M" Production Company, DeSoto Drilling, Inc., Southwestern Field Services, LLC, DeSoto Sand, LLC, SWN International, LLC, Southwestern NGV Services, LLC and A.W. Realty Company. Mr. Way is also a director of the Company's subsidiaries, SEECO, Inc., Southwestern Energy Production Company, DeSoto Drilling, Inc., Diamond "M" Production Company, Southwestern Midstream Services Company and Southwestern Energy Services Company. 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. Kerley was appointed to his present position in December 1999. He was elected to the Board of Directors in August 2010. Previously, he served as Senior Vice President and Chief Financial Officer from 1998 to 1999, Senior Vice President-Treasurer and Secretary from 1997 to 1998, Vice President-Treasurer and Secretary from 1992 to 1997, and Controller from 1990 to 1992. Mr. Kerley also served as the Chief Accounting Officer from 1990 to 1998. Prior to joining us, Mr. Kerley held senior financial and accounting positions at Agate Petroleum, Inc. and was a manager for Arthur Andersen, L.L.P. specializing in the energy sector. Mr. Kerley is the executive vice president of the Company's subsidiaries, Southwestern Field Services, LLC, DeSoto Sand, LLC, SWN International, LLC, SWN Resources Canada, Inc., Southwestern NGV Services, LLC and A.W. Realty Company. Mr. Kerley is also a director of the Company's subsidiaries, SEECO, Inc., Southwestern Energy Production Company, DeSoto Drilling, Inc., Diamond "M" Production Company, SWN Resources Canada, Inc., Southwestern Midstream Services Company, Southwestern Energy Services Company, Certified Title Company and A.W. Realty Company.

Mr. Boling was appointed to his present position in December 2002. He joined us as Senior Vice President, General Counsel and Secretary in January 2002. He is also the secretary of all of the Company's subsidiaries and a director of the Company's subsidiaries, SEECO, Inc., Southwestern Energy Production Company, DeSoto Drilling Inc., Southwestern Midstream Services Company, Southwestern Energy Services Company, Diamond "M" Production Company, A.W. Realty Company, Certified Title Company and SWN Resources Canada, Inc. 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. Hammons was appointed President of Southwestern Midstream Services Company, and its subsidiaries, Desoto Gathering Company, LLC, Angelina Gathering Company, LLC, Southwestern Energy Services Company in December 2005. He joined the company in July 2005 as Vice President of Southwestern Midstream Services Company. He is also President of SWN Producer Services, LLC and a director of Southwestern Midstream Services Company and Southwestern Energy Services Company. Prior to joining us, he provided consulting services to clients in the natural gas industry. Previously, Mr. Hammons was employed by El Paso Natural Gas Company and Burlington Resources and held managerial positions in facility design and installation, gathering management and marketing over the course of his combined 28-year tenure.

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 22, 2012 ("2011 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 2012 Proxy Statement for information concerning our directors. We refer you to the section “Corporate Governance – Committees of the Board of Directors” in the 2012 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 2012 Proxy Statement for information relating to compliance with Section 16(a) of the Exchange Act.

The Company has adopted a code of ethics that applies to the Company’s Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer. The full text of such code of ethics has been posted on the Company’s 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 2011 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 2012 Proxy Statement.

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

The 2012 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 2012 Proxy Statement. Refer to the sections “Security Ownership of Certain Beneficial Owners” and “Share Ownership of Management, Directors and Nominees” in our 2012 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 2012 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 2012 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 2012 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 Company 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, 2012

BY: /s/ GREG D. KERLEY
Greg D. Kerley
Executive 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, 2012.

/s/ HAROLD M. KORELL Harold M. Korell	Director, Chairman of the Board
/s/ STEVEN L. MUELLER Steven L. Mueller	Director, President and Chief Executive Officer
/s/ GREG D. KERLEY Greg D. Kerley	Director, Executive Vice President and Chief Financial Officer
/s/ ROBERT C. OWEN Robert C. Owen	Controller and Chief Accounting Officer
/s/ LEWIS E. EPLEY, JR Lewis E. Epley, Jr	Director
/s/ ROBERT L. HOWARD Robert L. Howard	Director
/s/ CATHERINE A. KEHR Catherine A. Kehr	Director
/s/ VELLO A. KUUSKRAA Vello A. Kuuskraa	Director
/s/ KENNETH R. MOURTON Kenneth R. Mourton	Director
/s/ CHARLES E. SCHARLAU Charles E. Scharlau	Director
/s/ ALAN H. STEVENS 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, effective February 23, 2012. (Incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed February 27, 2012)
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	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)
4.13	Third Amended and Restated Credit Agreement dated February 14, 2011 among Southwestern Energy Company, JPMorgan Chase Bank, NA, Bank of America, N.A., Wells Fargo N.A., The Royal Bank of Scotland PLC, Citigroup, 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 February 18, 2011)
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.
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.
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	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)
10.16	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)
10.17	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)
10.18	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)
10.19	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)
10.20*	Form of Non-Qualified Stock Option Agreement for awards granted on or after December 8, 2011.
10.21	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)
10.22	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)
10.23	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)
10.24	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)
10.25	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 30, 2012.
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