SOUTHWESTERN ENERGY CO
Form 10-K
February 21, 2013

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, 2012
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. Yesx 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 Nox
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. Yesx 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). Yesx 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 x 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 x

The aggregate market value of the voting stock held by non-affiliates of the registrant was $ 10,933,390,189 based on the New York Stock Exchange Composite Transactions closing price on June 29, 2012 of $31.93. For purposes of this calculation, the registrant has assumed that its directors and executive officers are affiliates.

As of February 15, 2013, the number of outstanding shares of the registrant s Common Stock, par value $0.01, was 351,097,392.

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 21, 2013 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, 2012

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This Annual Report on Form 10-K includes certain statements that may be deemed to be forward-looking within the meaning of Section 27A of the Securities Act of 1933, or the Securities Act, and Section 21E of the Securities Exchange Act of 1934, or the Exchange Act. We refer you to Risk Factors in Item 1A of Part I and to Management s Discussion and Analysis of Financial Condition and Results of Operations Cautionary Statement about Forward-Looking Statements in Item 7 of Part II of this Form 10-K for a discussion of factors that could cause actual results to differ materially from any such forward-looking statements. The electronic version of this Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and amendments to those forms filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act are available free of charge as soon as reasonably practicable after they are filed with the Securities and Exchange Commission, or SEC, on our website at www.swn.com. Our corporate governance guidelines and the charters of the Audit, 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.

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

ITEM 1. BUSINESS

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

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 natural 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 natural 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 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 primarily 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 natural gas reserves, and conducts the Fayetteville Shale drilling program and the conventional Arkoma Basin operations in the Arkoma Basin. SEPCO conducts development drilling, exploration programs and production operations in Pennsylvania, Oklahoma, Texas, Arkansas and Louisiana. SWN Drilling Company, Inc., formerly known as DeSoto Drilling, Inc., a wholly-owned subsidiary of SEPCO, operates drilling rigs in Arkansas, Pennsylvania and Louisiana, as well as other operating areas. We also provide oilfield products and services through DeSoto Sand, L.L.C. and SWN Well Services, L.L.C., both of which are wholly-owned subsidiaries of SWN E&P Services, L.L.C. 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., or DeSoto Gathering, and Angelina Gathering Company, L.L.C., or Angelina Gathering. DeSoto Gathering and Angelina Gathering primarily support our E&P operations and generate revenue from fees associated with gathering of natural gas. 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 2012, 64% of our operating income and 79% of our EBITDA were generated from our E&P business, absent our $1,939.7 million, or $1,192.4 million net of taxes, non-cash ceiling test impairment of our natural gas and oil properties, compared to 77% of our operating income and 84% of our EBITDA in 2011, and 81% of our operating income and 86% of our EBITDA in 2010. In 2012, 36% of our operating income and 21% of our EBITDA were generated from Midstream Services, absent the non-cash ceiling test impairment of our natural gas and oil properties, compared to 23% of our operating income and 16% of our EBITDA in 2011, and 19% of our operating income and 14% of our EBITDA in 2010. 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).

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:

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 for each project is determined using a 10% discount rate. We target creating at least $1.30 of pre-tax PVI for each dollar we invest in our E&P projects. Our actual PVI results are utilized to help determine the allocation of our future capital investments. The key elements of our business strategy are:

- Exploit and Develop Our Positions in the Fayetteville Shale and the Marcellus Shale Plays. 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. As of December 31, 2012, we held approximately 913,502 net acres in the Fayetteville Shale play, accounting for approximately 75% of our total proved oil and natural gas reserves and approximately 86% of our total oil and natural gas production during 2012. Additionally, we are actively drilling on portions of our 176,298 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 plays 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, 2012, we held 3,819,128 net undeveloped acres in connection with our New Ventures prospects, of which 2,518,518 net acres are located in New Brunswick, Canada.
- Maximize Efficiency through Vertical Integration and Economies of Scale. In our key operating areas, the concentration of our properties allows us to achieve economies of scale that result in lower costs. We seek to serve as the operator of the wells in which we have a significant interest. As the operator, we are better positioned to control the enhancing, drilling, completing and producing of wells and the marketing of production to minimize costs and maximize both production volumes and realized price. In the Fayetteville Shale play, we have achieved significant cost savings through ownership of our sand mine that is a source of proppant for our well completions and from our other associated oilfield services including operating a fleet of drilling rigs designed specifically for the play. In late-2012, we also began providing pressure pumping services for a certain number of our operated well completions in the Fayetteville Shale play.
- Enhance 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, 2012, we have invested approximately $1,038 million in the 1,852 mile gas gathering system built for our Fayetteville Shale play, which was gathering approximately 2.3 Bcf per day at year-end, and have invested approximately $203 million in 82 miles of gas gathering lines in Pennsylvania and in East Texas. Our gathering system in the Fayetteville Shale play has developed into a strategic asset that not only supports our E&P operations but also has improved our overall returns on a stand-alone basis.

Recent Developments

2013 Planned Capital Investments and Production Guidance. Our planned capital investment program for 2013 is approximately $2.0 billion, which includes approximately $1.8 billion for our E&P segment, $160 million for our Midstream Services segment and $40 million for corporate and other purposes. Our 2013 capital program is expected to be funded primarily by our cash flow from operations and borrowings under our $1.5 billion unsecured revolving credit facility. The planned capital program for 2013 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 2013 natural gas and oil production of approximately 628 to 640 Bcfe, an increase of approximately 12% over our 2012 production, using midpoints.

Exploration and Production

Overview

Our operations in our E&P segment are focused primarily 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 unconventional horizontal oil plays targeting the Lower Smackover Brown Dense, or LSBD, formation in Arkansas and Louisiana, the Marmaton and Atoka formations in the Denver-Julesburg Basin in Colorado, the Bakken and Three Forks formations in Montana 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.

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Our E&P segment recorded an operating loss of $1,411.2 million in 2012 as a result of the recognition of a $1,939.7 million, or $1,192.4 million net of taxes, non-cash ceiling test impairment of our natural gas and oil properties recorded for the twelve months ended December 31, 2012. Our E&P segment recorded operating income of $825.1 million in 2011 and operating income of $829.5 million in 2010. Our operating income in 2012 decreased as the revenue impact of our 13% increase in production was more than offset by the 18% decline in our average realized gas prices, the ceiling test impairment and an increase in operating costs and expenses that resulted from our significant production growth. 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. EBITDA from our E&P segment was $1.3 billion in 2012, compared to $1.5 billion in 2011 and $1.4 billion in 2010. Our EBITDA decreased in 2012 as our increased production was more than offset by lower average realized gas prices and increased operating costs and expenses that resulted from our significant production growth. The increase in our EBITDA in 2011 was due to our increased production volumes which was partially offset by lower average realized gas prices 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 4,018 Bcfe at year-end 2012, compared to 5,893 Bcfe at year-end 2011 and 4,937 Bcfe at year-end 2010. The overall decrease in total estimated proved reserves in 2012 was primarily due to the low natural gas price environment. Since our proved reserves are primarily natural gas and as such our reserve estimates and the after-tax PV-10 measure is highly dependent upon the natural gas price used in the after-tax PV-10 calculation. The average prices utilized to value our estimated proved natural gas and oil reserves as of December 31, 2012 were $2.76 per MMBtu for natural gas and $91.21 per barrel for oil compared to $4.12 per MMBtu for natural gas and $92.71 per barrel for oil at December 31, 2011 and $4.38 per MMBtu for natural gas and $75.96 per barrel for oil at December 31, 2010.

The after-tax PV-10, or standardized measure of discounted future net cash flows relating to proved natural gas and oil reserve quantities, was $2.1 billion at year-end 2012, compared to $3.5 billion at year-end 2011 and $3.0 billion at year-end 2010. The decrease in our after-tax PV-10 value in 2012 was primarily caused by the low natural gas price environment. The increase in our after-tax PV-10 value in 2011 over 2010 was primarily due to the increase in our reserves, partially offset by a decrease in average 2011 prices for natural gas from average 2010 prices. The difference in after-tax PV-10 and pre-tax PV-10 (a non-GAAP measure which is reconciled in the 2012 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 2012 estimated proved reserves had a present value of estimated future net cash flows before income tax, or pre-tax PV-10, of $2.3 billion, compared to $4.8 billion at year-end 2011 and $4.3 billion at year-end 2010.

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 2012 estimated proved reserves were natural gas and 80% were classified as proved developed, compared to approximately 100% and 55%, respectively, in both 2011 and 2010. We operate approximately 97% of our reserves, based on the pre-tax PV-10 value of our proved developed producing reserves, and our reserve life index approximated 7.1 years at year-end 2012. Natural gas sales accounted for nearly 100% of total operating revenues for this segment in 2012, 2011 and 2010.

The following table provides an overall and categorical summary of our oil and natural gas reserves, as of fiscal year-end 2012 based on average fiscal year prices, and our well count, net acreage and PV-10 as of December 31, 2012 and sets forth 2012 annual information related to production and capital investments for each of our operating areas:

2012 PROVED RESERVES BY CATEGORY AND SUMMARY OPERATING DATA

	Fayetteville Shale Play		Marcellus Shale Play		Ark-La-Tex East Texas		Arkoma Basin		New Ventures		Total
Estimated Proved Reserves:											
Natural Gas (Bcf):											
Developed (Bcf)	2,624		374		51		146		1		3,196
Undeveloped (Bcf)	364		442		1		14				821
	2,988		816		52		160		1		4,017
Crude Oil (MMBbls):											
Developed (MMBbls)					0.1				0.1		0.2
Undeveloped (MMBbls)											
					0.1				0.1		0.2
Total Proved Reserves (Bcfe)[1]:											
Proved Developed (Bcfe)	2,624		374		52		146		1		3,197
Proved Undeveloped (Bcfe)	364		442		1		14				821
	2,988		816		53		160		1		4,018
Percent of Total	75%		20%		1%		4%				100%
Percent Proved Developed	88%		46%		97%		91%		100%		80%
Percent Proved Undeveloped	12%		54%		3%		9%				20%
Production (Bcfe)	486		54		11		14				565
Capital Investments (millions)[2]	$ 991		$ 507		$ 5		$ 6		$ 337		$ 1,846
Total Gross Producing Wells[3]	3,228		132		173		1,180		4		4,717
Total Net Producing Wells[3]	2,186		71		110		570		4		2,941
Total Net Acreage	788,849	(4)	176,298	(5)	49,340	(6)	238,940	(7)	3,822,344	(8)	5,075,771
Net Undeveloped Acreage	308,924	(4)	159,078	(5)	1,874	(6)	63,341	(7)	3,819,128	(8)	4,352,345
PV-10:											
Pre-tax (millions)[9]	$ 1,693		$ 483		$ 30		$ 112		$ 6		$ 2,324
PV of taxes (millions)[9]	199		57		3		14				273
After-tax (millions)[9]	$ 1,494		$ 426		$ 27		$ 98		$ 6		$ 2,051

Percent of Total	73%	21%	1%	5%		100%
Percent Operated[10]	97%	99%	97%	89%	100%	97%

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

(2) Our Total and Fayetteville Shale play capital investments exclude $15 million related to our drilling rig related equipment, sand facility and other equipment.

(3) Represents all producing wells, including wells in which we only have an overriding royalty interest, as of December 31, 2012.

(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 46,007 net acres in 2013, 183,824 net acres in 2014, which includes 153,863 net acres held on federal lands, and 39,071 net acres in 2015.

(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 41,860 net acres in 2013, 13,467 net acres in 2014 and 3,835 net acres in 2015.

(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 1,340 net acres in 2013, 152 net acres in 2014 and 202 net acres in 2015.

(7) Includes 123,442 net developed acres and 1,211 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 1,200 net acres in 2013, 670 net acres in 2014 and 17,788 net acres in 2015.

(8) 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 1,120 net acres in 2013, 60,294 net acres in 2014 and 142,294 net acres in 2015. With regard to the company s acreage in New Brunswick, Canada, 2,518,518 net acres will expire in March 2015. We have applied for an additional 1-year option to extend our exploration license agreements and, if granted by the Province of New Brusnwick, this would extend our exploration license agreements until March 2016. With regard to our acreage in the LSBD play, assuming successful wells are not drilled and leases are not extended, leasehold expiring over the next three years will be 68,023 net acres in 2013, 237,181 net acres in 2014 and 159,718 net acres in 2015.

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

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

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

Proved Undeveloped Reserves

As of December 31, 2012, we had 821 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 2012, we invested $518 million in connection with converting 493.2 Bcfe or 19% of our proved undeveloped reserves as of December 31, 2011 into proved developed reserves and added 336.8 Bcfe of proved undeveloped reserve additions, primarily in the Fayetteville and Marcellus Shale plays. Our 2012 proved undeveloped reserve additions are expected to be developed and to begin to generate cash inflows over the next five years. At December 31, 2011, we had 2,633 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 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.

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 821 Bcfe as of December 31, 2012 will require us to invest an additional $698 million 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 effect on us, We may have difficulty financing our planned capital investments, which could adversely affect our growth and Our level of indebtedness and the terms of our financing arrangements may adversely affect operations and limit our growth in Item 1A of Part I of this Form 10-K and to Management s Discussion and Analysis of Financial Condition and Results of Operations Cautionary Statement about Forward-Looking Statements in Item 7 of Part II of this Form 10-K for a more detailed discussion of these factors and other risks.

Our Reserve Replacement

The 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.

In 2012, we replaced our production volumes with 919.5 Bcfe of proved reserve additions as a result of our drilling program, but also incurred net downward revisions of 2,088.2 Bcfe principally due to a decrease in the price of natural gas and to a lesser extent due to downward performance revisions of 336.4 Bcfe. Of the reserve additions, 582.8 Bcfe were proved developed and 336.7 Bcfe were proved undeveloped. The total downward reserve revisions were primarily impacted by the low commodity price environment in 2012 and to a lesser extent by downward performance revisions.

In 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.

For the period ending December 31, 2012, our three-year average reserve replacement ratio, including revisions, was 141%. Our reserve replacement ratio for 2012, excluding the effect of reserve revisions, was 163%, compared to 292% in 2011 and 354% in 2010. Excluding reserve revisions, our three-year average reserve replacement ratio is 259%.

Since 2005, the substantial majority of our reserve additions have been generated from our drilling program in the Fayetteville Shale play. Over the past several years, the Marcellus Shale play has contributed an increasing amount to our reserve additions. 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 play and Marcellus Shale play 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. As of December 31, 2012, we held leases for approximately 913,502 net acres in the play area (310,135 net undeveloped acres, 479,925 net developed acres held by Fayetteville Shale production and 123,442 net acres held by conventional production in the traditional Fairway portion of the Arkoma Basin), compared to approximately 925,842 net acres at year-end 2011 and 915,884 net acres at year-end 2010.

Approximately 2,988 Bcf of our reserves at year-end 2012 were attributable to our Fayetteville Shale play, compared to approximately 5,104 Bcf at year-end 2011 and 4,345 Bcf at year-end 2010. Our reserves in the Fayetteville Shale play decreased by 2,116 Bcf, which included net downward price revisions of 1,684 Bcf, 362 Bcf of downward revisions due to well performance, and production of 486 Bcf, partially offset by reserve additions of 415 Bcf. Gross production from our operated wells in the Fayetteville Shale play increased from approximately 1,947 MMcf per day at the beginning of 2012 to approximately 2,090 MMcf per day by year-end. Our net production from the Fayetteville Shale play was 485.5 Bcf in 2012, compared to 436.8 Bcf in 2011 and 350.2 Bcf in 2010. In 2013, we estimate our net production from the Fayetteville Shale play will be in the range of 475 to 480 Bcf.

At year-end 2012, after excluding our acreage in the traditional Fairway and the federal acreage we hold in the Ozark Highlands Unit, approximately 80% of our 605,409 total net leasehold acres remaining in the Fayetteville Shale was held by production. For more information about our acreage and well count, we refer you to Properties in Item 2 of Part 1 of this Form 10-K. Excluding our acreage in the traditional Fairway, our acreage position was obtained at an average cost of approximately $313 per acre and has an average royalty interest of 15%. In 2013, we expect to earn 13 sections or approximately 5,700 net acres, representing 3% of our drilling program. As of December 31, 2012, excluding our acreage in the traditional Fairway and our federal acreage, the undeveloped portion of our acreage had an average remaining lease term of 1.3 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, 2012, we had spud a total of 3,586 wells in the play since its commencement in 2004, 3,034 of which were operated by us and 552 of which were outside-operated wells. Of the wells spud, 491 were in 2012, 650 were in 2011 and 658 were in 2010. Of the wells spud in 2012, 485 were designated as horizontal wells. At year-end 2012, 2,874 operated wells had been drilled and completed overall, including 2,783 horizontal wells. Of the 2,783 horizontal wells, 2,765 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 $2.5 million per well, average horizontal lateral length of 4,833 feet and average time to drill to total depth of 6.7 days from re-entry to re-entry in 2012. This compares to an average completed operated 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 7.9 days from re-entry to re-entry during 2011. In 2010, our average completed operated well cost was $2.8 million per well with an average horizontal lateral length of 4,528 feet and average time to drill to total depth of 10.9 days from re-entry to re-entry. The operated wells we placed on production during 2012 averaged initial production rates of 3,629 Mcf per day, compared to average initial production rates of 3,330 Mcf per day in 2011 and 3,364 Mcf per day in 2010. The increase in initial production rates in 2012 was primarily due to the optimization of our drilling plan in the first quarter of 2012 toward areas in the field with the highest-return wells. As a result, our average initial production rates on a per well basis were significantly higher, particularly during the last half of 2012. The decrease in initial production rates in 2011 was primarily due to increased well density and locational differences in the mix of wells. During 2012, we placed 60 operated wells on production with initial production rates that exceeded 5.0 MMcf per day.

Our total proved net reserves booked in the play at year-end 2012 were from a total of 3,508 locations, of which 3,175 were proved developed producing, 123 were proved developed non-producing and 210 were proved undeveloped. Of the 3,508 locations, 3,468 were horizontal. The average gross proved reserves for the undeveloped wells included in our year-end 2012 was approximately 2.8 Bcf per well, compared to 2.4 Bcf per well at both year-end 2011 and year-end 2010. Total proved net natural gas reserves booked in the play in 2011 totaled approximately 5,104 Bcf from a total of 4,376 locations, of which 2,735 were proved developed producing, 59 were proved developed non-producing and 1,582 were proved undeveloped. Total proved net natural 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.

In 2012, we invested approximately $991 million in our Fayetteville Shale play, which included approximately $877 million to spud 491 wells, 453 of which we operated. Included in our total capital investments in the play during 2012 was $110 million in capitalized costs and other expenses and $4 million for acquisition of properties. In 2011, we invested approximately $1.3 billion in our Fayetteville Shale play, which included $1.2 billion to spud 650 wells, $10 million for acquisition of properties, and $132 million in capitalized costs and other expenses. 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. As of December 31, 2012, 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 2013, we plan to invest approximately $830 million in our Fayetteville Shale play, which includes participating in approximately 385 to 390 gross wells, all of which we plan to operate.

We believe that our Fayetteville Shale acreage continues to have significant development potential. Our strategy is to continue our development drilling, increase the amount of acreage we hold by production and determine the economic viability of the undrilled portion of our acreage. Our drilling program with respect to our Fayetteville Shale 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 for the Fayetteville Shale play and Marcellus Shale play are subject to change in Item 1A of Part I of this Form 10-K.

Marcellus Shale Play

We began leasing acreage in northeastern Pennsylvania in 2007 in an effort to gain a position in the emerging Marcellus Shale play. As of December 31, 2012, we had approximately 176,298 net acres in Pennsylvania under which we believe the Marcellus Shale play is present (159,078 net undeveloped acres and 17,220 net developed acres held by production), compared to approximately 186,893 net acres at year-end of 2011 and 173,009 net acres at year-end 2010. Our undeveloped acreage position as of December 31, 2012 had an average remaining lease term of three years and an average royalty interest of 15% and was obtained at an average cost of approximately $1,273 per acre.

As of December 31, 2012, we had spud 160 operated wells, 72 of which were on production and 153 of which will be horizontal wells. In 2012, we invested approximately $507 million in the Marcellus Shale play and spud 92 operated wells, resulting in reserve additions of 500 Bcf. Of these 92 wells, 34 will be horizontal wells located in our Greenzweig area in Bradford County, 15 will be horizontal wells located in Lycoming County and the remaining 43 wells are located in our Price and Range Trust areas in Susquehanna County. Our operated horizontal wells had an average completed well cost of $6.1 million per well, average horizontal lateral length of 4,070 feet and an average of 12 fracture stimulation stages in 2012. This compares to an average completed operated well cost of $7.0 million per well, average horizontal lateral length of 4,223 feet and an average of 14 fracture stimulation stages in 2011. In 2010, our average completed operated well cost was $6.0 million per well with an average horizontal lateral length of 3,602 feet and an average of nine fracture stimulation stages. Included in our total capital investments in the play during 2012 was approximately $400 million for drilling and completions, $24 million for acquisition of properties, $6 million for seismic and $77 million in facilities, capitalized costs and other expenses. In 2011, we invested approximately $332 million in the Marcellus Shale play and spud 43 operated wells, resulting in net reserve additions and revisions of 327 Bcf. In 2010, we invested approximately $118 million in the Marcellus Shale play and spud 21 operated wells, resulting in net reserve additions of 38 Bcf.

Approximately 816 Bcf of our total proved net reserves at year-end 2012 were attributable to the Marcellus Shale play. The company had a total of 71 operated horizontal wells and one operated vertical well which were on production as of December 31, 2012, resulting in net production from this area of 53.6 Bcf in 2012, compared to 23.4 Bcf in 2011 and 1.0 Bcf in 2010. Our reserves booked in the Marcellus Shale play included a total of 203 locations, of which 129 were proved developed producing, one was proved developed non-producing and 73 were proved undeveloped. The average gross proved reserves for the undeveloped wells included in our year-end reserves for 2012 was approximately 7.6 Bcf per well, up from 7.5 Bcf per well at year-end 2011 and 3.0 Bcf per well in 2010.

In 2013, we plan to invest approximately $705 million in the Marcellus Shale play and expect to participate in a total of 86 to 88 gross wells in 2013, all of which will be operated by us. In 2013, we estimate our net production from the Marcellus Shale play will be in the range of 134 to 139 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 for the Fayetteville Shale play and Marcellus Shale play 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 25.6 Bcfe in 2012, compared to 39.8 Bcfe in 2011 and 53.5 Bcfe in 2010. The decline in production from these areas during 2012 and 2011 was primarily driven by asset dispositions as well as natural field production declines and lower capital investments in these areas since 2009. In May 2012, we sold our oil and natural gas leases, wells and gathering equipment in approximately 19,800 net acres in the Overton Field in East Texas for approximately $166.0 million. 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 the Ark-La-Tex division in 2013. In 2012, we invested approximately $11 million in our Ark-La-Tex division and added new reserves of 3 Bcfe. Total proved net reserves from these areas were approximately 213 Bcfe as of December 31, 2012, compared to 447 Bcfe at year-end 2011 and 554 Bcfe at year-end 2010. In 2013, we expect to invest approximately $15 million in our Ark-La-Tex division.

New Ventures

We actively seek to find and develop new oil and natural gas plays with significant exploration and exploitation potential, which we refer to as New Ventures. We have been focusing on both oil and natural gas unconventional plays, and the technological methods best suited to developing these plays, such as horizontal drilling and fracture stimulation techniques. New Ventures prospects are evaluated based on 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, 2012, we held 3,819,128 net undeveloped acres in connection with our New Ventures prospects, of which 2,518,518 net acres were located in New Brunswick, Canada. This compares to 3,600,314 net undeveloped acres held at year-end 2011 and 3,009,643 net undeveloped acres held at year-end 2010.

In March 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 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. In December 2012, we received two one-year extensions to our exploration license agreements which expire on March 16, 2014 and March 16, 2015, respectively. Since 2010, we have conducted airborne gravity and magnetics surveys, surface geochemistry surveys and, as of December 31, 2012, had acquired 248 miles of 2-D seismic data. While preliminary interpretation has already begun, in 2013 we intend to acquire an additional 130 additional miles of 2-D seismic data. Through December 31, 2012, we have invested approximately $25.8 million USD in our New Brunswick exploration program towards our commitment, 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. As of December 31, 2012, we held approximately 504,486 net undeveloped acres in the area, obtained at an average cost of $419 per acre. Our leases currently have approximately an 81% average net revenue interest and an average primary lease term of approximately four years, which may be extended for approximately four additional years. We have drilled six operated wells in the play area to date, including two that are currently shut-in for further testing and one that was temporarily abandoned. Three wells are currently producing, two of which are horizontal wells. We are encouraged by our results to date and if our drilling program yields positive results, we expect that activity in the play could increase significantly over the next several years.

We have approximately 301,918 net acres in the Denver-Julesburg Basin in eastern Colorado where we have begun testing an unconventional oil play targeting middle and late Pennsylvanian to Permian-age carbonates and shales. We have drilled a horizontal well and a vertical well, both of which are testing multiple intervals.

We also have drilled a horizontal oil well in Sheridan County, Montana, targeting the Bakken and Three Forks objectives. We are continuing to lease acreage and plan to permit and drill additional wells in the area in 2013.

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 New Venture acreage could decline, and Our exploration, development and drilling efforts and our operation of our wells may not be profitable or achieve our targeted returns in Item 1A of Part I of this Form 10-K.

Divestitures

In May 2012, we sold certain oil and natural gas leases, wells and gathering equipment in the Overton Field in East Texas for approximately $166 million. The sale included approximately 19,800 net acres in Smith County, Texas. Net production from the field was approximately 24 MMcfe per day as of the closing date and proved net reserves were approximately 143 Bcfe as of year-end 2011.

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 completed in May 2011.

Capital Investments

During 2012, we invested a total of $1.9 billion in our E&P business and participated in drilling 595 wells, 383 of which were successful, and 203 which were in progress at year-end. Of the 203 wells in progress at year-end, 133 were located in our Fayetteville Shale play. Of the approximately $1.9 billion invested in our E&P business in 2012, approximately $991 million was invested in our Fayetteville Shale play, $507 million in our Marcellus Shale play, $5 million in East Texas, $6 million in our conventional Arkoma Basin program and $337 million in New Ventures projects.

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

In 2013, we plan to invest approximately $1.8 billion in our E&P program and participate in drilling 480 to 490 gross wells, all of which we plan to operate. The Fayetteville Shale play and Marcellus Shale play will be the primary focus of our capital investments, with planned investments of approximately $830 and $705 million, respectively. Our planned 2013 capital investments also include approximately $235 million in unconventional exploration and New Ventures projects and $15 million in our Ark-La-Tex division.

Of the $1.8 billion allocated to our 2013 E&P capital budget, approximately $1.3 billion will be invested in development and exploratory drilling, $14 million in seismic and other geological and geophysical expenditures, $109 million in acquisition of properties and $318 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 2013.

Sales, Delivery Commitments and Customers

Sales. Our daily natural gas equivalent production averaged 1,543.7 MMcfe in 2012, compared to 1,370.0 MMcfe in 2011 and 1,108.8 MMcfe in 2010. Total natural gas equivalent production was 565.0 Bcfe in 2012, up from 500.0 Bcfe in 2011 and 404.7 Bcfe in 2010. Our natural gas production was 564.5 Bcf in 2012, compared to 499.4 Bcf in 2011 and 403.6 Bcf in 2010. The increase in production in 2012 resulted primarily from a 48.7 Bcf increase in net production from our Fayetteville Shale play, a 30.3 Bcf increase in net production from our Marcellus Shale play, and a 0.3 Bcfe increase in net production from our New Ventures plays, which more than offset a combined 14.3 Bcfe decrease in net production from our East Texas and Arkoma Basin properties. The increase in production in 2011 resulted primarily from an 86.6 Bcf increase in production from the Fayetteville Shale play and a 22.4 Bcf increase in our Marcellus Shale play production, which more than offset a combined 13.7 Bcfe decrease in net production from our East Texas and Arkoma Basin properties. We also produced 83,000 barrels of oil in 2012, compared to 97,000 barrels of oil in 2011 and 171,000 barrels of oil in 2010. Our oil production has decreased between 2012 and 2011 primarily due to the divestiture of certain East Texas properties and the natural production decline in existing wells. For 2013, we are targeting total net natural gas and oil production of approximately 628 to 640 Bcfe, which represents a growth rate of approximately 12% over our 2012 production volumes, using midpoints.

Sales of natural gas and oil production are conducted under contracts that reflect current prices and are subject to seasonal price swings. We are unable to predict changes in the market demand and price for natural gas, including changes that may be induced by the effects of weather on demand for our production. We periodically enter into various hedging and other financial arrangements with respect to a portion of our projected natural gas and oil production 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. As of December 31, 2012, we had New York Mercantile Exchange, or NYMEX commodity price hedges in place on 185.6 Bcf, or approximately 29% of our targeted 2013 natural gas production and 18.3 Bcf of our expected 2014 natural gas production. We intend to hedge additional future production volumes to the extent natural gas prices rise to levels that we believe will achieve certain desired levels of cash flow. We refer you to Item 7A of this Form 10-K, Quantitative and Qualitative Disclosures about Market Risks, for further information regarding our hedge position as of December 31, 2012.

Including the effect of hedges, we realized an average wellhead price of $3.44 per Mcf for our natural gas production in 2012, compared to $4.19 per Mcf in 2011 and $4.64 per Mcf in 2010. Our hedging activities increased our average realized natural gas sales price $1.10 per Mcf in 2012, $0.63 per Mcf in 2011 and $0.71 per Mcf in 2010. Our average oil price realized was $101.54 per barrel in 2012, compared to $94.08 per barrel in 2011 and $76.84 per barrel in 2010. None of our oil production was hedged during 2012, 2011 or 2010.

During 2012, the average price received for our natural gas production, excluding the impact of hedges, was approximately $0.45 Mcf lower than average NYMEX prices. Assuming a NYMEX commodity price for 2013 of $3.50 per Mcf of natural gas, we expect to receive an average sales price for our natural gas production $0.50 to $0.55 per Mcf below the NYMEX Henry Hub average settlement price, excluding the impact of hedges. In 2013, we expect to incur average third-party transportation charges in the range of $0.35 to $0.40 per Mcf and average fuel charges in the range of 0.35% to 0.50% of our sales price for natural gas and we expect our average basis differential to be approximately $0.10 per Mcf less than NYMEX.

Delivery Commitments. As of February 1, 2013, we had natural gas delivery commitments of 337 Bcf in 2013 and 86 Bcf in 2014 under existing agreements. These commitments require the delivery of natural gas in Arkansas, Pennsylvania and Texas. These amounts are well below our forecasted 2013 and anticipated 2014 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, 2012, 2011 and 2010, 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

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 has increased our access to markets for our natural gas production, these markets are also served by a number of other suppliers. Consequently, we will encounter competition that may affect both the price we receive and contract terms we must offer. Outside Arkansas, we are less established and face competition from a larger number of other producers.

We 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 and potentially other New Venture areas. Hydraulic fracturing involves using water, sand, and certain chemicals to fracture the hydrocarbon-bearing rock formation to allow the flow of hydrocarbons into the wellbore. In our Fayetteville Shale and Marcellus Shale plays, the fracturing fluids we use are comprised of 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, phosphoric 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, or 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, the EPA issued final rules effective as of October 15, 2012 that subject oil and gas operations (production, processing, transmission, storage and distribution) to regulation under the New Source Performance Standards, or NSPS, and National Emission Standards for Hazardous Air Pollutants, or NESHAPS programs. The EPA final rules also include NSPS standards for completions of hydraulically fractured gas wells. These standards include the reduced emission completion, or REC techniques developed in the EPA's Natural Gas STAR program. The standards would be applicable to newly drilled and fractured wells as well as existing wells that are refractured. Further, the final regulations under NESHAPS include maximum achievable control technology, or MACT, standards for those glycol dehydrators and storage vessels at major sources of hazardous air pollutants not currently subject to MACT standards. Based on our current operations and practices, management believes, such newly promulgated rules will not have a material adverse impact on our financial position, results of operations or cash flows but these matters are subject to inherent uncertainties and management s view may change in the future.

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

In addition to the EPA s efforts, legislation has been introduced before Congress, called the Fracturing Responsibility and Awareness of Chemicals Act, to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process. There are also certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. A number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, and while initial results were expected to be available by late 2012 and final results by 2014, to date the EPA has not released any results from the study. In addition, the U.S. Department of Energy is conducting an investigation into practices the agency could recommend to better protect the environment from drilling using hydraulic fracturing completion methods. 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 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, however the provincial government has been working on a new comprehensive regulatory framework that is expected to be released to the public in late 2013.

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

Midstream Services

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

Our operating income from this segment was $294.3 million on revenues of $2.4 billion in 2012, compared to $248.0 million on revenues of $2.9 billion in 2011 and $191.6 million on revenues of $2.5 billion in 2010. Revenues increased in 2012 and 2011 primarily due to increased gathering revenues and increased volumes marketed. EBITDA generated by our Midstream Services segment was $338.8 million in 2012, compared to $285.1 million in 2011 and $220.5 million in 2010. The increases in 2012 and 2011 operating income and EBITDA were primarily due to increased gathering revenues and 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 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 2012, we invested approximately $165.0 million related to these activities and had gathering revenues of

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$474.0 million, compared to $160.8 million invested and revenues of $408.2 million in 2011 and $271.3 million invested and revenues of $316.0 million in 2010.

DeSoto Gathering is expanding its network of gathering lines and facilities throughout the Fayetteville Shale play area. During 2012, DeSoto Gathering gathered approximately 780.7 Bcf of natural gas volumes in the Fayetteville Shale play area, including 56.0 Bcf of natural gas from third-party operated wells. 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 wells. In 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. The increase in volumes gathered over the past three years was primarily due to our growing production volumes from the Fayetteville Shale play. At the end of 2012, DeSoto Gathering had approximately 1,852 miles of pipe from the individual wellheads to the transmission lines and compression equipment representing in aggregate approximately 531,470 horsepower had been installed at 61 central point gathering facilities in the field.

Angelina Gathering currently engages in gathering activities in Pennsylvania and in East Texas. Angelina Gathering is expanding its network of gathering lines and facilities throughout the Marcellus Shale play area. During 2012, Angelina Gathering gathered approximately 64.7 Bcf of natural gas volumes in the Marcellus Shale play and East Texas areas, including 0.1 Bcf of natural gas from third-party operated wells. During 2011, Angelina Gathering gathered approximately 42.1 Bcf of natural gas volumes in the Marcellus Shale play and East Texas areas, including 0.2 Bcf of natural gas from third-party wells. In 2010, Angelina Gathering gathered approximately 25.6 Bcf of natural gas volumes in the Marcellus Shale play and East Texas areas, including 0.7 Bcf of natural gas from third-party wells. The increase in volumes gathered over the past three years was primarily due to our growing production volumes from the Marcellus Shale play. At year-end 2012, Angelina Gathering had approximately 57 miles of pipe in Pennsylvania and 25 miles of pipe in Texas. As of December 31, 2012, compression equipment representing in aggregate approximately 28,195 horsepower had also been installed at 3 central point gathering facilities in Pennsylvania.

Gas Marketing

Our gas marketing subsidiary, SES, allows us to capture downstream opportunities related to marketing and transportation of natural gas. SES purchases natural gas and sells it to end-users, manages basis risk and marketing portfolio and acquires transportation rights on third-party pipelines. Our current marketing operations primarily relate to the marketing of our own natural gas production and some third-party natural gas. During 2012, we marketed 676.2 Bcf of natural gas, compared to 611.4 Bcf in 2011 and 495.8 Bcf in 2010. Of the total volumes marketed, production from our E&P operated wells accounted for 95% in 2012, compared to 94% in 2011 and 95% in 2010.

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, which have already been constructed by Texas Gas Transmission, LLC, or Texas Gas, a subsidiary of Boardwalk Pipeline Partners, LP, or Boardwalk Pipeline Partners. 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 and 2012, 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. Expansions of the system are expected to be in-service by the second quarter of 2013. In June 2011, SES entered into separate 15 year agreements with each of Bluestone Pipeline Company of Pennsylvania, LLC (Bluestone Gathering), and Susquehanna Gathering Company I, LLC, both wholly owned subsidiaries of DTE Pipeline Company, an affiliate of DTE Energy Company. Bluestone Gathering committed to build and operate a natural gas gathering system in Susquehanna County, Pennsylvania and Broome County, New York, and provide gathering services to SES in support of a portion of our future Marcellus Shale natural gas production. This gathering system was initially placed into service in November 2012 and is expected to be fully completed during the first quarter of 2013. Susquehanna Gathering Company I, LLC. committed to build and operate gathering infrastructure from well pad receipt locations for deliveries into the Bluestone Gathering system as well as other potential field delivery points. This system was first placed into service November 2012 and will be constructed as necessary to support the company s activities primarily in Susquehanna County. SES also executed firm transportation agreements with Tennessee Gas Pipeline Company (TGP) that increase our ability to move our Marcellus Shale natural gas production in the short term to market as well as a precedent agreement for an expansion project with a projected in-service date of November 2013 pursuant to which SES has subscribed for 100,000 Dekatherm per day of capacity. TGP s expansion project will expand its 300 Line in Pennsylvania to provide natural gas transportation from the Marcellus Shale supply area to existing delivery points on the TGP system. TGP filed a certificate application for the project with the Federal Energy Regulatory Commission issued a certificate on August 9, 2012. Construction would begin in second quarter 2013, with a projected November 1, 2013 in-service date. On March 23, 2012, SES entered into a precedent agreement with Constitution Pipeline Co. LLC for a proposed 121-mile pipeline connecting to the Iroquois Gas Transmission and Tennessee Gas Pipeline systems in Schoharie County, New York. Subject to the receipt of regulatory approvals and satisfaction of other conditions, SES agreed to enter a 15 year firm transportation agreement with a total capacity of 150 MMcf per day on this project. The project is expected to be in service by the second quarter of 2015. In March 2012, SES entered into a firm transportation agreement with TGP to utilize existing transportation capacity to various delivery points on TGP s system. SES agreed to enter into a 10 year firm transportation agreement with a total capacity of 130 MMcf per day on this project. The project went into service in November 2012. 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, 2012, SES s and SEPCO s obligations for demand and similar charges under the firm transportation agreements and gathering agreements totaled approximately $2.8 billion and the Company has guarantee obligations of up to $100.0 million of that amount.

Competition

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

Regulation

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 of 1938, or NGA, 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 No. 720 remains in effect. Compliance with Order No. 720 has not had a material adverse impact on our operations.

Other

Our other operations have primarily consisted of real estate development activities concentrated on tracts of land located in Arkansas. During 2012, we sold our office complex in Fayetteville, Arkansas, our interest in approximately 9.5 acres of real estate near the Fayetteville complex and our office complex in Conway, Arkansas for approximately $32.2 million. Subsequently, we leased back our Conway complex from the buyer for a 15 year term. We also purchased 26 acres near The Woodlands, Texas for a future office site. There were no sales of commercial real estate in 2011 or 2010.

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, impairment of natural gas and oil properties, and 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, 2012, 2011 and 2010:

	E&P	Midstream Services	Other	Total
2012				
Net income (loss) attributable to Southwestern Energy	$(884,126)	$175,570	$1,492	$(707,064)
Impairment of natural gas and oil properties	1,939,734			1,939,734
Depreciation, depletion and amortization	765,368	44,395	1,190	810,953

Net interest expense	20,315	14,341	1,001	35,657
Provision (benefit) for income taxes	(548,556)	104,522	895	(443,139)
EBITDA	$1,292,735	$338,828	$4,578	$1,636,141
2011				
Net income 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 (benefit) for income taxes	323,748	67,834	77	391,659
EBITDA	$1,391,000	$220,510	$762	$1,612,272

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 and the prevention and cleanup of pollutants and other matters. We maintain insurance against costs of clean-up operations, but we are not fully insured against all such risks. Although future environmental obligations are not expected to have a material impact on the results of our operations or financial condition, there can be no assurance that future developments, such as increasingly stringent environmental laws or enforcement thereof, will not cause us to incur material environmental liabilities or costs.

Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal fines and penalties and the imposition of injunctive relief.&