CONSOL Energy Inc
Form 10-K
February 07, 2014

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

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2013

OR

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

For the transition period from to

Commission file number: 001-14901

CONSOL Energy Inc.
(Exact name of registrant as specified in its charter)

Delaware	51-0337383
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

1000 CONSOL Energy Drive
Canonsburg, PA 15317-6506
(724) 485-4000
(Address, including zip code, and telephone number, including area code, of registrant's principal executive offices)

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

Title of each class	Name of exchange on which registered
Common Stock ($.01 par value)	New York Stock Exchange
Preferred Share Purchase Rights	New York Stock Exchange

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

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

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 o No x

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 x No o

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 x No o

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of “large accelerated filer,” “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act. (Check one):
Large accelerated filer x Accelerated filer o Non-accelerated filer o Smaller Reporting Company o
Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
Yes o No x
The aggregate market value of voting stock held by nonaffiliates of the registrant as of June 30, 2013, the last business day of the registrant's most recently completed second fiscal quarter, based on the closing price of the common stock on the New York Stock Exchange on such date was $3,294,530,080.
The number of shares outstanding of the registrant's common stock as of January 20, 2014 is 229,162,591 shares.
DOCUMENTS INCORPORATED BY REFERENCE:
Portions of CONSOL Energy's Proxy Statement for the Annual Meeting of Shareholders to be held on May 7, 2014, are incorporated by reference in Items 10, 11, 12, 13 and 14 of Part III.

TABLE OF CONTENTS

		Page
PART I		
ITEM 1.	Business	5
ITEM 1A.	Risk Factors	29
ITEM 1B.	Unresolved Staff Comments	44
ITEM 2.	Properties	44
ITEM 3.	Legal Proceedings	44
ITEM 4.	Mine Safety and Health Administration Safety Data	44
PART II		
ITEM 5.	Market for Registrant's Common Equity and Related Stockholder Matters and Issuer Purchases of Equity Securities	45
ITEM 6.	Selected Financial Data	47
ITEM 7.	Management's Discussion and Analysis of Financial Condition and Results of Operations	49
ITEM 7A.	Quantitative and Qualitative Disclosures About Market Risk	104
ITEM 8.	Financial Statements and Supplementary Data	106
ITEM 9.	Changes in and Disagreements with Accountants on Accounting and Financial Disclosures	179
ITEM 9A.	Controls and Procedures	179
ITEM 9B.	Other Information	181
PART III		
ITEM 10.	Directors and Executive Officers of the Registrant	181
ITEM 11.	Executive Compensation	182
ITEM 12.	Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters	182
ITEM 13.	Certain Relationships and Related Transactions and Director Independence	182
ITEM 14.	Principal Accounting Fees and Services	182
PART IV		
ITEM 15.	Exhibits and Financial Statement Schedules	183
SIGNATURES		191

GLOSSARY OF CERTAIN OIL AND GAS MEASUREMENT TERMS

The following are abbreviations of certain measurement terms commonly used in the oil and gas industry and included within this Form 10-K:

Bbl - One stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to oil or other liquid hydrocarbons.
Bcf - One billion cubic feet of natural gas.
Bcfe - One billion cubic feet of natural gas equivalents, with one barrel of oil being equivalent to 6,000 cubic feet of gas.
Btu - One British thermal unit.
Mbbls - One thousand barrels of oil or other liquid hydrocarbons.
Mcf - One thousand cubic feet of natural gas.
Mcfe - One thousand cubic feet of natural gas equivalents, with one barrel of oil being equivalent to 6,000 cubic feet of gas.
MMbtu - One million British Thermal units.
MMcfe - One million cubic feet of natural gas equivalents, with one barrel of oil being equivalent to 6,000 cubic feet of gas.
NGL - Natural gas liquids.
Tcfe - One trillion cubic feet of natural gas equivalents, with one barrel of oil being equivalent to 6,000 cubic feet of gas.

FORWARD-LOOKING STATEMENTS

We are including the following cautionary statement in this Annual Report on Form 10-K to make applicable and take advantage of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 for any forward-looking statements made by, or on behalf of us. With the exception of historical matters, the matters discussed in this Annual Report on Form 10-K are forward-looking statements (as defined in Section 21E of the Exchange Act) that involve risks and uncertainties that could cause actual results to differ materially from projected results. Accordingly, investors should not place undue reliance on forward-looking statements as a prediction of actual results. The forward-looking statements may include projections and estimates concerning the timing and success of specific projects and our future production, revenues, income and capital spending. When we use the words “believe,” “intend,” “expect,” “may,” “should,” “anticipate,” “could,” “estimate,” “plan,” “predict,” “project,” or their negatives, or other expressions, the statements which include those words are usually forward-looking statements. When we describe strategy that involves risks or uncertainties, we are making forward-looking statements. The forward-looking statements in this Annual Report on Form 10-K speak only as of the date of this Annual Report on Form 10-K; we disclaim any obligation to update these statements unless required by securities law, and we caution you not to rely on them unduly. We have based these forward-looking statements on our current expectations and assumptions about future events. While our management considers these expectations and assumptions to be reasonable, they are inherently subject to significant business, economic, competitive, regulatory and other risks, contingencies and uncertainties, most of which are difficult to predict and many of which are beyond our control. These risks, contingencies and uncertainties relate to, among other matters, the following:

- deterioration in global economic conditions in any of the industries in which our customers operate, or sustained uncertainty in financial markets cause conditions we cannot predict;
- an extended decline in demand for or prices we receive for our natural gas and coal affecting our operating results and cash flows;
- our customers extending existing contracts or entering into new long-term contracts for coal;
- our reliance on major customers;

- our inability to collect payments from customers if their creditworthiness declines;
- the disruption of rail, barge, gathering, processing and transportation facilities and other systems that deliver our natural gas and coal to market;
- a loss of our competitive position because of the competitive nature of the natural gas and coal industries, or a loss of our competitive position because of overcapacity in these industries impairing our profitability;
- coal users switching to other fuels in order to comply with various environmental standards related to coal combustion emissions;
- the impact of potential, as well as any adopted regulations relating to greenhouse gas emissions on the demand for natural gas and coal;
- foreign currency fluctuations could adversely affect the competitiveness of our coal abroad;
- the risks inherent in natural gas and coal operations being subject to unexpected disruptions, including geological conditions, equipment failure, timing of completion of significant construction or repair of equipment, fires, explosions, accidents and weather conditions which could impact financial results;
- decreases in the availability of, or increases in, the price of commodities or capital equipment used in our mining operations;
- decreases in the availability of, an increase in the prices charged by third party contractors or, failure of third party contractors to provide quality services to us in a timely manner could impact our profitability;

- obtaining and renewing governmental permits and approvals for our natural gas and coal operations;
- the effects of government regulation on the discharge into the water or air, and the disposal and clean-up of, hazardous substances and wastes generated during our natural gas and coal operations;
- our ability to find adequate water sources for our use in gas drilling, or our ability to dispose of water used or removed from strata in connection with our gas operations at a reasonable cost and within applicable environmental rules;
- the effects of stringent federal and state employee health and safety regulations, including the ability of regulators to shut down a natural gas well or a mine;
- the potential for liabilities arising from environmental contamination or alleged environmental contamination in connection with our past or current gas and coal operations;
- the effects of mine closing, reclamation, gas well closing and certain other liabilities;
- uncertainties in estimating our economically recoverable gas and coal reserves;
- defects may exist in our chain of title and we may incur additional costs associated with perfecting title for gas or coal rights on some of our properties or failing to acquire these additional rights may result in a reduction of our estimated reserves;
- the impacts of various asbestos litigation claims;
- the outcomes of various legal proceedings, which are more fully described in our reports filed under the Securities Exchange Act of 1934;
- increased exposure to employee-related long-term liabilities;
- lump sum payments made to retiring salaried employees pursuant to our defined benefit pension plan exceeding total service and interest cost in a plan year;
- acquisitions that we recently have completed or may make in the future including the accuracy of our assessment of the acquired businesses and their risks, achieving any anticipated synergies, integrating the acquisitions and unanticipated changes that could affect assumptions we may have made and divestitures we anticipate may not occur or produce anticipated proceeds;
- the terms of our existing joint ventures restrict our flexibility, actions taken by the other party in our gas joint ventures may impact our financial position and various circumstances could cause us not to realize the benefits we anticipate receiving from these joint ventures;
- risks associated with our debt;
- replacing our natural gas reserves, which if not replaced, will cause our gas reserves and gas production to decline;
- our hedging activities may prevent us from benefiting from price increases and may expose us to other risks;
- changes in federal or state income tax laws, particularly in the area of percentage depletion and intangible drilling costs, could cause our financial position and profitability to deteriorate;
- failure to appropriately allocate capital and other resources among our strategic opportunities may adversely affect our financial condition;
- failure by Murray Energy to satisfy liabilities it acquired from us, or failure to perform its obligations under various arrangements, which we guaranteed, could materially or adversely affect our results of operations, financial position, and cash flows; and
- other factors discussed in this 2013 Form 10-K under “Risk Factors,” as updated by any subsequent Form 10-Qs, which are on file at the Securities and Exchange Commission.

PART I

ITEM 1. Business

General

CONSOL Energy is an integrated energy company operated through two primary divisions, oil and gas exploration and production (E&P) and coal mining. The E&P division is focused on Appalachian area natural gas and liquids activities, including production, gathering, processing and acquisition of natural gas properties in the Appalachian Basin. The coal division is focused on the extraction and preparation of coal, also in the Appalachian Basin.

CONSOL Energy was incorporated in Delaware in 1991, but its predecessors had been mining coal, primarily in the Appalachian Basin, since 1864. CONSOL Energy entered the natural gas business in the 1980s initially to increase the safety and efficiency of our coal mines by capturing methane from coal seams prior to mining, which makes the mining process safer and more efficient. Over the past ten years, CONSOL Energy's natural gas business has grown by approximately 290% to produce 172.4 net Bcfe in 2013. This business has grown from coalbed methane production in Virginia into other unconventional production, such as the Marcellus Shale and Utica Shale, in the Appalachian Basin.

Our Gas Division operates, develops and explores for natural gas primarily in Appalachia (Pennsylvania, West Virginia, Virginia, Ohio, and Tennessee). Currently, our primary focus is the continued development of our Marcellus Shale acreage and the exploration and development of our Utica Shale acreage. We believe that our concentrated operating area, our legacy surface acreage position, our regional operating expertise, our geological logs from nearly 100 years of shallow oil and gas drilling activity in the region, our held by production acreage position, and our ability to coordinate gas drilling with coal mining activity gives us a significant operating advantage over our competitors. We expect to produce 215-235 Bcfe for 2014 and achieve 30% annual gas production growth in 2015 and 2016.

We are also party to two strategic joint ventures, one with Noble Energy, Inc. (Noble) in the Marcellus Shale and one with a subsidiary of Hess Corporation (Hess) in the Utica Shale. These joint ventures require our partners to pay a portion of our qualifying drilling and completion cost's in certain circumstances, which improves drilling economics and enables the acceleration of development of these assets.

Our land holdings in the Marcellus Shale and Utica Shale plays cover large areas, provide multi-year drilling opportunities and, collectively, have sustainable lower risk growth profiles. We currently control approximately 446 thousand net acres in the Marcellus Shale and approximately 109 thousand net acres in the Utica Shale. In addition, we estimate that approximately 345 thousand net acres of our Marcellus Shale acreage in Pennsylvania and West Virginia are prospective for the slightly shallower Upper Devonian Shale. We also have 2.5 million net acres in our coalbed methane play, primarily in Virginia.

Highlights of our 2013 production include the following:
- Total production of 472,274 Mcfe per day, an increase of 10% over 2012;
- 98% Natural Gas, 2% Liquids; and
- 34% Marcellus, 48% coalbed methane, 16% shallow oil & gas, 2% other.

At December 31, 2013, our proved reserves had the following characteristics:
- 5.7 Tcfe of proved reserves;
- 97.5% natural gas;
- 43.9% proved developed;

- 85.7% operated; and
- A reserve life ratio of 33.25 years (based on fourth quarter 2013 production);

On December 5, 2013, we sold Consolidation Coal Company and certain subsidiaries, including five active coal mines in West Virginia, to a subsidiary of Murray Energy Corporation (the "Murray Energy Transaction"). These coal mines produced 26.7 million tons of thermal coal in 2013 and had approximately 1.1 billion tons of coal reserves. After the Murray Energy transaction, our coal division continues to focus on the extraction and processing of coal primarily in Pennsylvania and Virginia.

Highlights of coal activities from continuing operations in 2013 include the following:
- Underground mining complexes are among the safest in the United States of America;
- Production of 28.5 million tons of coal from continuing operations;
- Coal reserve holdings of 3.0 billion tons;
- 30% of sales delivered to export markets;
- 59% of sales to domestic utilities; and
- New BMX Mine in southwest Pennsylvania scheduled to come on-line in March 2014, as planned.

Additionally, we provide energy services, including terminal services (the Baltimore Terminal), industrial supply services, water services and land resource management services.

The following map provides the location of CONSOL Energy's gas and coal operations by region:
CONSOL Energy's Strategy

CONSOL Energy's strategy is to increase shareholder value through growth of its existing gas assets, selective acquisition of gas and liquids acreage leases within its footprint, and through participation in the forecasted global growth of thermal and metallurgical coal markets. We also will continue to focus on monetization of assets to accelerate value creation to minimize the shortfall between operating cash flows and our growth capital requirements.

CONSOL Energy intends to continue to grow its gas production. The 2014 gas production guidance range is 215-235 Bcfe, net to CONSOL Energy, of which 5-8% is expected to be liquids. For 2015 and 2016, the company expects 30% annual gas production growth.

We expect natural gas to become a more significant contributor to the domestic electric generation mix as well as fueling industrial growth in the U.S. economy. Also, natural gas may potentially become a significant contributor to the transportation market. Our increasing gas production will allow CONSOL Energy to participate in these growing markets.

The 2014 coal production guidance range is 30.1 - 32.1 million tons. CONSOL Energy’s coal assets align with the company’s long term strategic objectives. The production from the company’s Pennsylvania Operations, which include the Bailey, Enlow Fork, and soon-to-be-completed BMX mines, can be sold domestically or abroad, as either thermal coal or high volatile metallurgical coal. These low-cost mines, with five longwalls, and with estimated production of nearly 24 million tons in 2014, produce a high-Btu Pittsburgh-seam coal that is lower in sulfur than many Northern Appalachian coals. Also, the company’s Buchanan Mine in southwestern Virginia produces a premium low volatile metallurgial coal for the steel industry. It typically produces 4-5 million tons per year at a cost that is among the lowest of any domestic metallurgical coal mine.

These mines along with the 100%-owned Baltimore Terminal, will continue to allow CONSOL Energy to participate in the growth of the world’s thermal and metallurgical coal markets. The International Energy Agency (IEA) forecasts meaningful continued growth in world demand for thermal coal. The ability to serve both domestic and international markets with premium thermal and metallurgical coal provides tremendous optionality.

CONSOL Energy defines itself through its core values which are:

- Safety,
- Compliance, and
- Continuous Improvement.

These values are the foundation of CONSOL Energy's identity and are the basis for how management defines continued success. We believe CONSOL Energy's rich resource base, coupled with these core values, allows management to create value for the long-term. The electric power industry generates over two-thirds of its output by burning natural gas or coal, the two fuels we produce. We believe that the use of natural gas and coal will continue for many years as the principal fuel sources for electricity in the United States. Additionally, we believe that as worldwide economies grow, the demand for electricity from fossil fuels will grow as well, resulting in expansion of worldwide demand for our coal and potentially natural gas.

CONSOL Energy's Capital Expenditure Budget-
The following table outlines CONSOL Energy's capital expenditure budget for 2014:

	Capex ($MM)
Natural Gas Operations:	
Land and Permitting:	$70
Liquids-rich drilling and completions:	
Marcellus	410
Utica	105
Dry-gas drilling and completions:	
Marcellus/Upper Devonian	415
Utica	10
CBM/Shallow Gas	40
Midstream:	
Marcellus Gathering	60
Total Natural Gas Operations	$1,110
Coal Operations:	
BMX Mine	$200
Maintenance of Production	130
Land/Safety/Water/Terminal	60

Total Coal Operations	$390
Total Company	$1,500

CONSOL Energy expects to invest about $1.1 billion in its natural gas operations, much of which will be directed toward drilling and completion costs in the highly productive Marcellus and Utica shales. Approximately one-half of the company's total drilling capital will target the liquids-rich areas within these two plays. On the dry gas side, drilling will primarily focus on those areas in the Marcellus shale that have established economics resulting from high net revenue interest, economies of scale, or reservoir performance.

Our joint venture partner is required to pay a portion of our drilling and completion costs in the certain circumstances. However, the Marcellus shale drilling and completions capital is not reduced because of the contingent nature of the drilling carry in place with the Marcellus shale joint venture. The Marcellus shale joint venture drilling carry is currently suspended and will be reinstated upon Henry Hub natural gas prices being equal to or greater than $4.00 per MMbtu for three consecutive months. Based on current Henry Hub futures and the expected corresponding reinstatement of the drilling carry, approximately $220 million of the Marcellus shale joint venture drilling carry is expected to be realized for drilling and completions capital incurred between March and December of the current year. The Utica shale drilling and completions capital reflects a $115 million reduction for drilling carry we expect to be paid by our joint venture partner.

DETAIL GAS OPERATIONS

Our Gas operations are located throughout Appalachia and include the following plays.

Marcellus Shale

We have the rights to extract natural gas in Pennsylvania, West Virginia, Ohio and New York from approximately 446,000 net Marcellus Shale acres at December 31, 2013.

CONSOL Energy and Noble Energy, our joint venture partner, drilled a record 117 gross wells in the Marcellus Shale in 2013. CONSOL Energy drilled 46 of those wells in the dry gas area of the formation. The geographic breakdown was as follows:

- 26 wells in Southwestern Pennsylvania,
- 10 wells in Central Pennsylvania,
- 10 wells in Northern West Virginia, and
- 71 wells drilled by Noble Energy in the wet gas area of the play.

CONSOL Energy also completed 59 Marcellus Shale wells in 2013. The average lateral length was 5,744 feet in 2013, or a 4% increase over the previous year's lateral length of 5,514 feet. These longer drilled laterals enabled the company to perform more hydraulic fracturing, or "fracking," to complete the wells. In 2013, the average completed well had 26 "frac" stages, or a 44% increase over the 18 stages from the previous year. Longer lateral lengths and more "frac" stages per well are expected to enhance well economics.

In 2014, the company expects Marcellus Shale drilling activity to be the primary driver of gas production growth. In the Marcellus Shale joint venture, CONSOL Energy and Noble Energy plan to operate an average of 4-5 horizontal rigs each to drill at least a combined 162 gross wells. At least 88 of the joint venture wells will be drilled in the liquids-rich areas of the play, including 2 within the recently acquired acreage that lies beneath the Pittsburgh International Airport. At least 74 wells are planned to target the dry gas area of the joint venture. These dry locations include 6 Upper Devonian laterals (5 Burkett; 1 Rhinestreet) in Washington County, Pennsylvania (4) and Doddridge County, West Virginia (2). Current plans of both partners include increased usage of shorter stage laterals and reduced cluster spacing. The early results of these enhanced completion techniques in Southwestern Pennsylvania have been very promising. The wells completed in this manner have shown initial production rates being improved by as much as 40%, which the company believes will translate into potential increases to well EURs of 15%-20%.

We also hold a 50% interest in a gathering company which builds and operates the gathering system for most of our Marcellus shale production. We contributed our existing Marcellus Shale gathering assets to this company as of September 30, 2011. Joint operations are conducted in accordance with a joint development agreement.

Utica

CONSOL Energy also controls approximately 109,000 net acres of Utica Shale potential in eastern Ohio at December 31, 2013. Additionally, CONSOL Energy controls a large number of acres in southwestern Pennsylvania and northern West Virginia that contain the rights to the Utica Shale. These acres are disclosed in other plays because the Utica Shale is not the primary drilling target as of December 31, 2013. The thickness of the Utica Shale in these areas range from 200 to 450 feet.
In 2013, CONSOL Energy and Hess, our joint venture partner, drilled 24 gross wells in the Utica. CONSOL Energy drilled 9 of those wells.
In the Utica Shale joint venture, a total of 32 gross wells are planned to be drilled in 2014 within the liquids-rich corridor that runs across Harrison, Belmont, Guernsey, and Noble counties of Ohio. CONSOL Energy and its partner will also test enhanced completion techniques in the Utica as efforts in 2014 will focus on ramping up production.
We and our joint venture partner are seeking to monetize approximately 62,000 gross joint venture Utica shale acres which are located outside of our core operating area.
Separate from the joint venture activity, CONSOL Energy expects to invest $24 million in Monroe County, Ohio in 2014. In addition to continuing to build-out its land position, the company will drill two 100%-owned wells. One well will target the liquids-rich Marcellus formation, while the other will be designed to penetrate the dry-gas Utica zone. Both will be drilled from the same pad.

Coalbed Methane (CBM)

We have the rights to extract CBM in Virginia from approximately 267,000 net CBM acres, which cover a portion of our coal reserves in Central Appalachia. We produce gas primarily from the Pocahontas #3 seam which is the main coal seam mined by our Buchanan Mine. For 2014, the coalbed methane program will again be kept at minimal drilling levels, with the expected drilling of 71 wells. Total capital for the 2014 CBM drilling program is estimated to be $34 million.

We also have the right to extract CBM in West Virginia, southwestern Pennsylvania, and Ohio from approximately 965,000 net CBM acres. In central Pennsylvania we have the right to extract CBM from approximately 263,000 net CBM acres. In addition, we control 808,000 net CBM acres in Illinois, Kentucky, Indiana, and Tennessee. We also have the right to extract CBM on 139,000 net acres in the San Juan Basin, and 20,000 net acres in the Powder River Basin. We have no plans to drill CBM wells in these areas in 2014.

Shallow Oil and Gas

The shallow oil and gas acreage position of CONSOL Energy is approximately 906,000 net acres mainly in Illinois, Indiana, Kentucky, West Virginia, Pennsylvania, Virginia, and New York at December 31, 2013. The majority of our shallow oil and gas leasehold position is held by production and all of it is extensively overlain by existing third party gas gathering and transmission infrastructure. The shallow oil and gas assets provide multiple synergies with our CBM and unconventional shale operations, and the held by production nature of the shallow oil and gas properties affords CONSOL Energy considerable flexibility to choose when to exploit those and other gas assets including shale assets. For 2014, the company continues to de-emphasize its shallow oil and gas program, and plans to drill a total of 5 wells.

Other Gas

Upper Devonian
The Upper Devonian Shale formation lies above the Marcellus Shale formation in southwestern Pennsylvania and northern West Virginia. The company holds a large number of acres that have Upper Devonian potential; generally

these acres have not been disclosed separately, since they are not the primary drilling target as of December 31, 2013.

CONSOL Energy's first Upper Devonian well, which was drilled in the Burkett Shale and turned in line in June 2013, continues to demonstrate a shallow decline rate and an EUR in the range of 5-6 Bcfe. CONSOL Energy expects to drill five additional Burkett Shale wells in 2014, as well as at least one Rhinestreet Shale formation well. Our Marcellus Shale joint venture partner owns a 50% interest in the Burkett Shale formation within the joint venture area of mutual interest, while CONSOL Energy controls a 100% interest in the Rhinestreet Shale formation.

Chattanooga

The Chattanooga Shale in Tennessee is a Devonian-age shale found at a depth of approximately 3,500 feet. The shale thickness is between 40-80 feet, and CONSOL Energy has found it to be rich in total organic content. CONSOL Energy has 243,000 net acres of Chattanooga Shale. This largely contiguous acreage is composed of only a small number of leases, a rarity in Appalachia. CONSOL Energy is the operator of all of its Chattanooga Shale wells.

Huron

We have 406,000 net acres of Huron Shale potential in Kentucky, West Virginia, and Virginia; a portion of this acreage has tight sands potential.

Summary of Properties as of December 31, 2013

	CBM Segment	Shallow Oil and Gas Segment	Marcellus Segment	Other Gas Segment	Total
Estimated Net Proved Reserves (MMcfe)	1,544,970	582,846	3,373,093	230,305	5,731,214
Percent Developed	73 %	100 %	21 %	34 %	44 %
Net Producing Wells (including gob wells)	4,310	8,324	132	108	12,874
Net Acreage Position					
Net Proved Developed Acres	258,601	248,318	11,527	9,247	527,693
Net Proved Undeveloped Acres	9,986	—	44,396	4,964	59,346
Net Unproved Acres(1)	2,193,699	625,706	380,964	1,011,661	4,212,030
Total Net Acres(2)	2,462,286	874,024	436,887	1,025,872	4,799,069

(1) Net acres include acreage attributable to our working interests in the properties. Additional adjustments (either increases or decreases) may be required as we further develop title to and further confirm our rights with respect to our various properties in anticipation of development. We believe that our assumptions and methodology in this regard are reasonable. See Risk Factors in Section 1A. of this Form 10-K.

(2) Acreage amounts are shown under the target strata CONSOL Energy expects to produce, although the reported acres may include rights to multiple gas seams (CBM, Shallow Oil and Gas, Marcellus, etc.). We have reviewed our drilling plans, our acreage rights and used our best judgment to reflect the acres in the strata we expect to produce. As more information is obtained or circumstances change, the acreage classification may change.

Producing Wells and Acreage

Most of our development wells and proved acreage is located in Virginia, West Virginia and Pennsylvania. Some leases are beyond their primary term, but these leases are extended in accordance with their terms as long as certain drilling commitments or other term commitments are satisfied. The following table sets forth, at December 31, 2013, the number of producing wells, developed acreage and undeveloped acreage:

	Gross	Net(1)
Producing Wells (including gob wells)	15,063	12,874
Net Acreage Position		
Proved Developed Acreage	542,388	527,693
Proved Undeveloped Acreage	105,019	59,346
Unproven Acreage	5,396,659	4,212,030
Total Acreage	6,044,066	4,799,069

(1) Net acres include acreage attributable to our working interests in the properties. Additional adjustments (either increases or decreases) may be required as we further develop title to and further confirm our rights with respect to

our various

properties in anticipation of development. We believe that our assumptions and methodology in this regard are reasonable. See Risk Factors in Section 1A. of this Form 10-K.

Development Wells (Net)

During the years ended December 31, 2013, 2012 and 2011 we drilled 139.8, 95.5 and 254.9 net development wells, respectively. Gob wells and wells drilled by operators other than our primary joint venture partners, Noble Energy and Hess Corporation, are excluded from net development wells. In 2013, there were 205 gross development wells. There were no dry development wells in 2013, 2012, or 2011. As of December 31, 2013, there are 31 net developmental wells still in process. The following table illustrates the net wells drilled by well classification type:

	For the Year Ended December 31,			
	2013	2012	2011	
CBM segment	63.8	42.5	221.4	
Shallow Oil and Gas segment	5.0	2.0	4.0	
Marcellus segment	56.0	44.0	17.5	(A)
Other Gas segment	15.0	7.0	12.0	
Total Development Wells	139.8	95.5	254.9	

(A) For the year ended December 31, 2011, the Marcellus Segment includes 15 gross development wells drilled prior to September 30, 2011. A 50% interest in these wells was sold to Noble Energy on September 30, 2011.

Exploratory Wells (Net)

During the years ended December 31, 2013, 2012 and 2011, we drilled in the aggregate 5.5, 22.0, and 69.5 net exploratory wells, respectively. As of December 31, 2013, there is 1.0 net exploratory well in process. In 2013, there were 11.0 gross exploratory wells. The following table illustrates the exploratory wells drilled by well classification type:

	For the Year Ended December 31,								
	2013			2012			2011		
	Producing	Dry	Still Eval.	Producing	Dry	Still Eval.	Producing	Dry	Still Eval.
CBM segment	—	—	—	—	—	—	—	—	—
Shallow Oil and Gas segment	—	—	—	4.0	7.0	4.0	12.0	1.0	1.0
Marcellus segment	0.5	—	2.0	0.5	—	0.5	47.5	1.0	—
Other Gas segment (1)	—	—	3.0	1.0	0.5	4.5	5.5	—	1.5
Total	0.5	—	5.0	5.5	7.5	9.0	65.0	2.0	2.5

(1) For the year ended December 31, 2013, the Other Gas Segment includes three net exploratory wells drilled in the Utica Shale in Ohio, all of which are still being evaluated.

For the year ended December 31, 2012, the Other Gas Segment includes five net exploratory wells drilled in the Utica Shale in Ohio.

For the year ended December 31, 2011, the Marcellus Segment includes 41 gross exploratory wells drilled prior to September 30, 2011. A 50% interest in these wells was sold to Noble Energy on September 30, 2011. There were a total of 15 gross exploratory wells drilled after September 30, 2011 under the joint venture agreement with Noble Energy and are reflected in the table above at the applicable ownership percentage.

Reserves

The following table shows our estimated proved developed and proved undeveloped reserves. Reserve information is net of royalty interest. Proved developed and proved undeveloped reserves are reserves that could be commercially recovered under

11

current economic conditions, operating methods and government regulations. Proved developed and proved undeveloped reserves are defined by the Securities and Exchange Commission (SEC).

	Net Reserves (Million cubic feet equivalent) as of December 31,		
	2013	2012	2011
Proved developed reserves	2,514,294	2,165,483	2,135,805
Proved undeveloped reserves	3,216,920	1,827,975	1,344,222
Total proved developed and undeveloped reserves(a)	5,731,214	3,993,458	3,480,027

(a) For additional information on our reserves, see "Other Supplemental Information–Supplemental Gas Data (unaudited) to the Consolidated Financial Statements in Item 8 of this Form 10-K.

Discounted Future Net Cash Flows

The following table shows our estimated future net cash flows and total standardized measure of discounted future net cash flows at 10%:

	Discounted Future Net Cash Flows (Dollars in millions)		
	2013	2012	2011
Future net cash flows	$6,568	$2,792	$4,877
Total PV-10 measure of pre-tax discounted future net cash flows (1)	$2,780	$1,242	$2,861
Total standardized measure of after tax discounted future net cash flows	$1,681	$736	$1,747

(1) We calculate our present value at 10% (PV-10) in accordance with the following table. Management believes that the presentation of the non-Generally Accepted Accounting Principle (GAAP) financial measure of PV-10 provides useful information to investors because it is widely used by professional analysts and sophisticated investors in evaluating oil and gas companies. Because many factors that are unique to each individual company impact the amount of future income taxes estimated to be paid, the use of a pre-tax measure is valuable when comparing companies based on reserves. PV-10 is not a measure of the financial or operating performance under GAAP. PV-10 should not be considered as an alternative to the standardized measure as defined under GAAP. We have included a reconciliation of the most directly comparable GAAP measure-after-tax discounted future net cash flows.

Reconciliation of PV-10 to Standardized Measure

	As of December 31,		
	2013	2012	2011
	(Dollars in millions)		
Future cash inflows	$21,603	$11,778	$14,804
Future production costs	(7,106)	(4,824)	(5,263)
Future development costs (including abandonments)	(3,903)	(2,451)	(1,675)
Future net cash flows (pre-tax)	10,594	4,503	7,866
10% discount factor	(7,814)	(3,261)	(5,005)
PV-10 (Non-GAAP measure)	2,780	1,242	2,861
Undiscounted income taxes	(4,026)	(1,711)	(2,989)
10% discount factor	2,927	1,205	1,875
Discounted income taxes	(1,099)	(506)	(1,114)
Standardized GAAP measure	$1,681	$736	$1,747

Gas Production

The following table sets forth net sales volumes produced for the periods indicated:

	For the Year Ended December 31,		
	2013	2012	2011
GAS			
Marcellus Sales Volumes (MMcf)	55,048	35,853	26,863
CBM Sales Volumes (MMcf)	82,867	88,149	92,360
Shallow Oil and Gas Sales Volumes (MMcf)	27,457	28,684	31,731
Other Sales Volumes (MMcf)	3,365	2,366	1,987
LIQUIDS*			
NGLs Sales Volumes (MMcfe)	2,628	610	—
Oil Sales Volumes (MMcfe)	634	600	563
Condensate Sales Volumes (MMcfe)	381	63	—
TOTAL (MMcfe)	172,380	156,325	153,504

*Oil, NGLs, and Condensate are converted to Mcfe at the rate of one barrel equals six Mcf based upon the approximate relative energy content of oil and natural gas.

CONSOL Energy projects its 2014 natural gas production to be between 215 - 235 Bcfe, of which 5%-8% is expected to be NGLs/condensates/oil. With the continued focus on the liquids-rich areas of its plays, the company expects that mix to increase to 10%-15% by the end of 2016, while overall volumes are expected to increase 30% per year over the the same time period.

Average Sales Price and Average Lifting Cost

The following table sets forth the total average sales price and the total average lifting cost for all of our gas production for the periods indicated, including intersegment transactions. Total lifting cost is the cost of raising gas to the gathering system and does not include depreciation, depletion or amortization. See Part II Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations in this Form 10-K for a breakdown by segment.

	For the Year Ended December 31, 2013	2012	2011
Total Average Gas Sales Price Before Effects of Financial Settlements (per Mcfe)	$3.85	$3.00	$4.27
Average Effects of Financial Settlements (per Mcfe)	$0.45	$1.22	$0.63
Total Average Gas Sales Price Including Effects of Financial Settlements (per Mcfe)	$4.30	$4.22	$4.90
Average Lifting Costs excluding ad valorem and severance taxes (per Mcfe)	$0.56	$0.58	$0.69

We enter into physical gas sales transactions with various counterparties for terms varying in length. Reserves and production estimates are believed to be sufficient to satisfy these obligations. In the past, we have delivered quantities required under these contracts. We also enter into various gas swap transactions that qualify as financial cash flow hedges. These gas swap transactions exist parallel to the underlying physical transactions and represented approximately 84.3 Bcf of our produced gas sales volumes for the year ended December 31, 2013 at an average price of $4.68 per Mcf. These gas swaps represented approximately 76.9 Bcf of our produced gas sales volumes for the year ended December 31, 2012 at an average price of $5.25 per Mcf. As of January 21, 2014, we expect these transactions will represent approximately 129.3 Bcf of our estimated 2014 production at an average price of $4.61 per Mcf, 78.6 Bcf of our estimated 2015 production at an average price of $4.10 per Mcf, and 71.3 Bcf of our estimated 2016 production at an average price of $4.20 per Mcf.

CONSOL Energy continues to develop a diversified portfolio of firm capacity transportation options to support our three-year production growth plan. We are benefited from the strategic location of our primary production areas in Southwest Pennsylvania, Northern West Virginia, and Eastern Ohio. These areas are served by a large concentration of major pipelines that provide us with the capacity to move our production to the major gas markets.

The hedging strategy and information regarding derivative instruments used are outlined in Part II, Item 7A Qualitative and Quantitative Disclosures About Market Risk and in Note 23 - Derivative Instruments in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K.

Midstream Gas Services

CONSOL Energy has traditionally designed, built and operated natural gas gathering systems to move gas from the wellhead to interstate pipelines or other local sales points. In addition, CONSOL Energy has acquired extensive gathering assets. CONSOL Energy now owns or operates approximately 4,600 miles of gas gathering pipelines as well as 250,000 horsepower of compression, of which, approximately 75% is wholly owned with the balance being leased. Along with this compression capacity, CONSOL Energy owns and operates a number of gas processing facilities. This infrastructure is capable of delivering 300 billion cubic feet per year of pipeline quality gas.

CONSOL Energy also owns 50% of CONE Gathering, LLC ("CONE" or "CONE Gathering") along with Noble Energy owning the other 50% interest. CONE Gathering develops, operates and owns both Noble Energy's and CONSOL Energy's Marcellus Shale gathering system needs. CONSOL Energy operates this equity affiliate. We believe that the network of right-of-ways, vast surface holdings and experience in building and operating gathering systems in the Appalachian basin will give CONE Gathering an advantage in building the midstream assets required to develop the joint venture's Marcellus Shale position.

In the Utica Shale, we and our joint venture partner, Hess, are primarily contracting with third parties for gathering services.

CONSOL Energy has had the advantage of having gas production from CBM, which can be lower Btu than pipeline specification, as well as higher Btu Marcellus Shale production which can complement each other by reducing and in some cases eliminating the need for the costly processing of CBM. In addition, both our lower Btu CBM and dry Marcellus production offers an opportunity to blend ethane back into the gas stream when pricing or capacity for ethane markets dictate. This will allow CONSOL Energy more flexibility in bringing Marcellus Shale wells on-line at qualities that meet interstate pipeline specifications.

Natural Gas Competition

The United States natural gas industry is highly competitive and more diversified than the coal industry. CONSOL Energy competes with other large producers, as well as thousands of smaller producers, pipeline imports from Canada, and Liquefied Natural Gas (LNG) from around the globe. According to data from the Natural Gas Supply Association and the Energy Information Agency (EIA), the five largest producers of natural gas produced about 20% of dry natural gas production in the first six months of 2013. The EIA reported 482,822 producing natural gas wells in the United States in 2012, the latest year for which government statistics are available.

Natural gas has lost three percent of market share in the U.S. electric generation market compared to record natural gas generation in 2012 (based on preliminary 2013 results). However, we expect natural gas to become a more significant contributor to the domestic electric generation mix in the long-term, as well as fuel industrial growth in the U.S. economy. There is potential for natural gas to become a significant contributor to the transportation market. Additionally, the U.S. is expected to become a net exporter of gas in the next few years. Our increasing gas production will allow CONSOL Energy to participate in these growing markets.
CONSOL Energy's gas operations are primarily located in the eastern United States. The gas market is highly fragmented and not dominated by any single producer. We believe that competition within our market is based primarily on natural gas commodity trading fundamentals and pipeline transportation availability to the various markets.

Continued demand for CONSOL Energy's natural gas and the prices that CONSOL Energy obtains are affected by natural gas use in the production of electricity, U.S. manufacturing and the overall strength of the economy, environmental and government regulation, technological developments and the availability and price of competing alternative fuel supplies.

DETAIL COAL OPERATIONS

Coal Reserves

At December 31, 2013, CONSOL Energy had an estimated 3.0 billion tons of proven and probable reserves, excluding equity affiliates. Reserves are the portion of the proven and probable tonnage that meet CONSOL Energy's economic criteria regarding mining height, preparation plant recovery, depth of overburden and stripping ratio. Generally, these reserves would be commercially mineable at year-end price and cost levels.

Spacing of points of observation for confidence levels in reserve calculations is based on guidelines in U.S. Geological Survey Circular 891 (Coal Resource Classification System of the U.S. Geological Survey). Our estimates for proven reserves have the highest degree of geologic assurance. Estimates for proven reserves are based on points of observation that are equal to or less than 0.5 miles apart. Estimates for probable reserves have a moderate degree of geologic assurance and are computed from points of observation that are between 0.5 to 1.5 miles apart.

An exception is made concerning spacing of observation points with respect to our Pittsburgh coal seam reserves. Because of the well-known continuity of this seam, spacing requirements are 3,000 feet or less for proven reserves and between 3,000 and 8,000 feet for probable reserves.

CONSOL Energy's estimates of proven and probable reserves do not rely on isolated points of observation. Small pods of reserves based on a single observation point are not considered; continuity between observation points over a large area is necessary for proven or probable reserves.

Our estimate of proven and probable coal reserves has been determined by CONSOL Energy's geologists and mining engineers. Our coal reserves are periodically reviewed by an independent third party consultant. In previous years, the independent consultant has reviewed the procedures used by us to prepare our internal estimates, verified the accuracy of our property reserve estimates and retabulated reserve groups according to standard classifications of reliability.

CONSOL Energy's proven and probable coal reserves fall within the range of commercially marketed coals in the United States. The marketability of coal depends on its value-in-use for a particular application, and this is affected by coal quality, such as, sulfur content, ash and heating value. Modern power plant boiler design aspects can compensate for coal quality differences that occur. Therefore, any of CONSOL Energy's coals can be marketed for the electric power generation industry. Additionally, the growth in worldwide demand for metallurgical coals allows some of our proven and probable coal reserves, currently classified as thermal coals, that possess certain qualities to be sold as metallurgical coal. The addition of this cross-over market adds additional assurance to CONSOL Energy that all of its proven and probable coal reserves are commercially marketable.

CONSOL Energy assigns coal reserves to each of our mining complexes. The amount of coal we assign to a mining complex generally is sufficient to support mining through the duration of our current mining permit. Under federal law, we must renew our mining permits every five years. All assigned reserves have their required permits or governmental approvals, or there is a high probability that these approvals will be secured.

In addition, our mining complexes may have access to additional reserves that have not yet been assigned. We refer to these reserves as accessible. Accessible reserves are proven and probable reserves that can be accessed by an existing mining complex, utilizing the existing infrastructure of the complex to mine and to process the coal in this area. Mining an accessible reserve does not require additional capital spending beyond that required to extend or to continue the normal progression of the mine, such as the sinking of airshafts or the construction of portal facilities.

Some reserves may be accessible by more than one mining complex because of the proximity of many of our mining complexes to one another. In the table below, the accessible reserves indicated for a mining complex are based on our review of current mining plans and reflect our best judgment as to which mining complex is most likely to utilize the reserve.

Assigned and unassigned coal reserves are proven and probable reserves which are either owned or leased. The leases have terms extending up to 30 years and generally provide for renewal through the anticipated life of the associated mine. These renewals are exercisable by the payment of minimum royalties. Under current mining plans, assigned reserves reported will be mined out within the period of existing leases or within the time period of probable lease renewal periods.

Mining Complexes

The following table provides the location of CONSOL Energy's active mining complexes and the coal reserves associated with each of the continuing operations.

CONSOL ENERGY MINING COMPLEXES

Proven and Probable Assigned and Accessible Coal Reserves as of December 31, 2013 and 2012

Mine/Reserve	Location	Reserve Class	Coal Seam	Average Seam Thickness (feet)	As Received Heat Value(1) (Btu/lb) Typical	Range	Recoverable Reserves(2) Owned (%)	Leased (%)	Tons in Millions 12/31/2013 (4)	12/31/2012
ASSIGNED–OPERATING										
Thermal Reserves										
Enlow Fork (3)	Enon, PA	Assigned	Pittsburgh	5.4	12,920	12,760 – 13,020	100%	—%	16.9	27.0
		Accessible	Pittsburgh	5.3	13,020	12,830 – 13,100	79%	21%	232.8	232.8
Bailey (3)	Enon, PA	Assigned	Pittsburgh	5.5	12,940	12,840 – 13,000	62%	38%	96.9	92.2
		Accessible	Pittsburgh	5.7	12,940	12,770 – 13,090	88%	12%	278.7	303.0
Amvest-Fola Complex (3)	Bickmore, WV	Assigned	Multiple	4.6	12,380	12,250 – 12,550	86%	14%	73.4	73.4
Miller Creek Complex	Delbarton, WV	Assigned	Multiple	2.6	12,050	11,600 – 12,650	44%	56%	52.6	13.4
		Accessible	Multiple	5.1	12,610	12,610 – 12,610	1%	99%	0.7	8.2
Metallurgical Reserves										
Buchanan	Mavisdale, VA	Assigned	Pocahontas 3	6.2	13,740	13,610 – 14,130	20%	80%	47.2	51.7
		Accessible	Pocahontas 3	5.9	13,720	13,630 – 13,870	14%	86%	46.1	46.3
Amonate Complex	Amonate, VA	Assigned	Multiple	4.2	13,150	12,850 – 13,350	64%	36%	20.1	14.8
		Accessible	Multiple	5.2	13,010	13,010 – 13,010	100%	—%	6.6	6.6
Total Assigned Operating and Accessible									872.0	869.4

(1) The heat value shown for Assigned Operating reserves is based on the quality of coal mined and processed during the year ended December 31, 2013. The heat value shown for accessible reserves are based on as received, dry values obtained from drill hole analysis prorated by the associated Assigned Operating reserve values to account for similar mining and processing methods.

(2) Recoverable reserves are calculated based on the area in which mineable coal exists, coal seam thickness and average density determined by laboratory testing of drill core samples. This calculation is adjusted to account for coal that will not be recovered during mining and for losses that occur if the coal is processed after mining. Reserve calculations do not include adjustments for moisture that may be added during mining or processing, nor do the calculations include adjustments for dilution from rock lying above or below the coal seam. Reserves are reported only for those coal seams that are controlled by ownership or leases.

(3) A portion of these reserves contain metallurgical qualities and are currently being sold on the metallurgical market.

(4) The table excludes 57 million tons of recoverable reserves which represents CONSOL Energy's portion of tonnage held by two equity affiliates. CONSOL Energy owns a 49% interest in both of these affiliates.

The following table sets forth our unassigned proven and probable reserves by region:
CONSOL Energy UNASSIGNED Recoverable Coal Reserves as of December 31, 2013 and 2012

Coal Producing Region	As Received Heat Value(1) (Btu/lb)	Recoverable Reserves(2) Owned (%)	Leased (%)	Tons in Millions 12/31/2013	Recoverable Reserves (tons in Millions) 12/31/2012
Northern Appalachia (Pennsylvania, Ohio, Northern West Virginia)	11,400 – 13,600	86%	14%	951.7	1,424.0
Central Appalachia (Virginia, Southern West Virginia)	11,400 – 14,100	54%	46%	349.6	354.7
Illinois Basin (Illinois, Western Kentucky, Indiana)	11,600 – 12,000	45%	55%	731.9	733.6
Total		65%	35%	2,033.2	2,512.3

(1) The heat value estimates for Northern Appalachian and Central Appalachian Unassigned coal reserves include adjustments for moisture that may be added during mining or processing as well as for dilution by rock lying above or below the coal seam. The mining and processing methods currently in use are used for these estimates. The heat value estimates for the Illinois Basin, unassigned reserves are based primarily on exploration drill core data that may not include adjustments for moisture added during mining or processing or for dilution by rock lying above or below the coal seam.

(2) Recoverable reserves are calculated based on the area in which mineable coal exists, coal seam thickness, and average density determined by laboratory testing of drill core samples. This calculation is adjusted to account for coal that will not be recovered during mining and for losses that occur if the coal is processed after mining. Reserve calculations do not include adjustment for moisture that may be added during mining or processing, nor do the calculations include adjustments for dilution from rock lying above or below the coal seam. Reserves are only reported for those coal seams that are controlled by ownership or leases.

18

The following table classifies CONSOL Energy coals by rank, projected sulfur dioxide emissions and heating value (British thermal units per pound). The table also classifies bituminous coals as high, medium and low volatile which is based on fixed carbon and volatile matter.

CONSOL Energy Proven and Probable Recoverable Coal Reserves
By Product (In Millions of Tons) As of December 31, 2013

	≤ 1.20 lbs. S02/MMBtu			> 1.20 ≤ 2.50 lbs. S02/MMBtu			> 2.50 lbs. S02/MMBtu				
By Region	Low Btu	Med Btu	High Btu	Low Btu	Med Btu	High Btu	Low Btu	Med Btu	High Btu	Total	Percent By Product
Metallurgical(1):											
High Vol A Bituminous	—	—	6.2	—	—	208.7	—	—	—	214.9	7.1 %
Med Vol Bituminous	—	5.1	56.1	—	—	2.9	—	—	—	64.1	2.1 %
Low Vol Bituminous	—	—	186.6	—	—	55.2	—	—	—	241.8	8.0 %
Total Metallurgical	—	5.1	248.9	—	—	266.8	—	—	—	520.8	17.2 %
Thermal(1):											
High Vol A Bituminous	34.5	80.4	2.8	41.5	105.2	61.5	66.8	62.2	1,289.7	1,744.6	57.5 %
High Vol B Bituminous	—	17.9	—	—	75.4	—	—	401.1	—	494.4	16.3 %
High Vol C Bituminous	—	—	—	—	159.4	—	108.3	—	—	267.7	8.8 %
Low Vol Bituminous	—	—	—	—	—	—	—	—	4.5	4.5	0.2 %
Total Thermal	34.5	98.3	2.8	41.5	340.0	61.5	175.1	463.3	1,294.2	2,511.2	82.8 %
Total	34.5	103.4	251.7	41.5	340.0	328.3	175.1	463.3	1,294.2	3,032.0	100.0 %
Percent of Total	1.1 %	3.4 %	8.3 %	1.4 %	11.2 %	10.8 %	5.8 %	15.3 %	42.7 %	100.0 %	

The table above excludes 57 million tons of reserves held by two equity affiliates. CONSOL Energy owns 49% of both of these affiliates.

Title to coal properties that we lease or purchase and the boundaries of these properties are verified by law firms retained by us at the time we lease or acquire the properties. Consistent with industry practice, abstracts and title reports are reviewed and updated approximately five years prior to planned development or mining of the property. If defects in title or boundaries of undeveloped reserves are discovered in the future, control of and the right to mine reserves could be adversely affected.

The following table sets forth, with respect to properties that we lease to other coal operators, the total royalty tonnage, acreage leased and the amount of income (net of related expenses) we received from royalty payments for the years ended December 31, 2013, 2012 and 2011.

Year	Total Royalty Tonnage (in thousands)	Total Coal Acreage Leased	Total Royalty Income (in thousands)
2013	8,335	271,755	$16,906
2012	8,326	271,760	$16,853
2011	8,488	289,833	$17,969

Royalty tonnage leased to third parties is not included in the amounts of produced tons that we report. Proven and probable reserves do not include reserves attributable to properties that we lease to third parties.

Production

In the year ended December 31, 2013, 94% of CONSOL Energy's production from continuing operations came from underground mines and 6% from surface mines. Where the geology is favorable and reserves are sufficient, CONSOL Energy employs longwall mining systems in our underground mines. For the year ended December 31, 2013, 90% of our production came from mines equipped with longwall mining systems. Underground longwall systems are highly mechanized, capital intensive operations. Mines using longwall systems have a low variable cost structure compared with other types of mines and can achieve high productivity levels compared with those of other underground mining methods. Because CONSOL Energy has substantial reserves readily suitable to these operations, CONSOL Energy believes that these longwall mines can increase capacity at a low incremental cost.
The following table shows the production from continuing operations, in millions of tons, for CONSOL Energy's mines for the years ended December 31, 2013, 2012 and 2011, the location of each mine, the type of mine, the type of equipment used at each mine, method of transportation and the year each mine was established or acquired by us.

					Tons Produced (in millions)			Year
		Mine	Mining					Established
Mine	Location	Type	Equipment	Transportation	2013	2012	2011	or Acquired
Thermal								
Bailey (3)	Enon, PA	U	LW/CM	R R/B	10.1	8.6	8.6	1984
Enlow Fork (3)	Enon, PA	U	LW/CM	R R/B	8.9	8.0	8.3	1990
Miller Creek Complex(2)	Delbarton, WV	U/S	CM/S/L	R T	2.2	2.9	2.8	2004
AMVEST-Fola Complex(1)(2)	Bickmore, WV	U/S	A/S/L/CM	R T	—	0.8	2.1	2007
High Volatile Metallurgical								
Bailey-Met (3)	Enon, PA	U	LW/CM	R R/B	1.3	1.5	2.1	1984
Enlow Fork-Met (3)	Enon, PA	U	LW/CM	R R/B	1.2	1.5	1.8	1990
AMVEST-Fola Complex(1)(2)-Met	Bickmore, WV	U/S	A/S/L/CM	R T	—	0.3	0.1	2007
AMVEST-Terry Eagle Complex(1)(2)-Met	Jodie, WV	U/S	CM/A/S/L	R T	—	—	0.1	2007
Low Volatile Metallurgical								
Buchanan(1)	Mavisdale, VA	U	LW/CM	R T	4.8	3.5	5.7	1983
Amonate (1)(2)	Amonate, VA	U/S	A/S/CM	R T	—	0.1	—	2012
Total					28.5	27.2	31.6	
CONSOL Energy Portion of Equity Affiliates								
Harrison Resources(2)(4)	Cadiz, OH	S	S/L	R T	0.4	0.4	0.4	2007
Western Allegheny-Knob Creek(2)(4)	Young Township, PA	U	CM	R T	0.3	0.1	0.1	2010
Total CONSOL Energy Portion of Equity Affiliates					0.7	0.5	0.5	

A – Auger
S – Surface
U – Underground
LW – Longwall
CM – Continuous Miner
S/L – Stripping Shovel and Front End Loaders
R – Rail
B – Barge

R/B	–	Rail to Barge
T	–	Truck
CB	–	Conveyor Belt
(1)	–	Mine was idled for part of the year(s) presented due to market conditions.
(2)	–	Harrison Resources, Miller Creek Complex, AMVEST–Fola Complex, AMVEST–Terry Eagle Complex, Amonate Complex and Western Allegheny–Knob Creek include facilities operated by independent contractors.
(3)	–	Mine was idle for three weeks during 2012 due to a structural failure at the above-ground conveyor system at the Bailey Preparation Plant. Production was then resumed at a reduced capacity.
(4)	–	Production amounts represent CONSOL Energy's 49% ownership interest.

Coal Capital

Coal operations anticipate investing $200 million in 2014 to complete the BMX Mine in mid-March. This underground mine is adjacent to CONSOL Energy's Bailey and Enlow Fork mines in Southwestern Pennsylvania. On a full-year basis, the single-longwall BMX Mine is expected to produce approximately 5 million annual tons of high-quality Pittsburgh seam coal to be sold in either the high volatile metallurgical or thermal markets.

Due to the well capitalized nature of the company's retained coal assets, we anticipate that maintenance-of-production capital for 2014 will be held to under $4.25 per ton on the 31 million tons expected to be produced for the year.

Coal Marketing and Sales

Our sales of bituminous coal from continuing operations were at average sales price per ton sold as follows:

	Years Ended December 31,		
	2013	2012	2011
Average Sales Price Per Ton Sold– Thermal Coal	$64.78	$69.08	$66.84
Average Sales Price Per Ton Sold– High Volatile Met Coal	$63.44	$63.93	$78.57
Average Sales Price Per Ton Sold– Low Volatile Met Coal	$92.64	$140.11	$191.81
Average Sales Price Per Ton Sold– Total Company	$69.34	$77.75	$90.10

We sell coal produced by our mining complexes and additional coal that is purchased by us for resale from other producers. We maintain United States sales offices in Charlotte, Philadelphia and Pittsburgh. In addition, we sell coal through agents and to brokers and unaffiliated trading companies.

A breakdown of total coal sales from continuing operations is as follows:

	Tons Sold	Percent of Total	
Thermal	21.4	74	%
High Volatile Metallurgical	2.5	9	%
Low Volatile Metallurgical	4.9	17	%
Total tons sold	28.8	100	%

Approximately 59% of our 2013 coal sales from continuing operations were made to U. S. electric generators, 30% of our 2013 coal sales were priced on export markets and 11% of our coal sales were made to other domestic customers. We had over 60 customers from our 2013 continuing operations. During 2013, Xcoal Energy Resources and Duke Energy Carolinas each comprised over 10% of our revenues from continuing operations, and the top four coal and gas customers accounted for more than 35% of our total revenues from continuing operations.

Coal Contracts

We sell coal to an established customer base through opportunities as a result of strong business relationships, or through a formalized bidding process. Contract volumes range from a single shipment to multi-year agreements for millions of tons of coal. The average contract term is between one to three years. However, several multi-year agreements have terms ranging from five to twenty years. As a normal course of business, efforts are made to renew or extend contracts scheduled to expire. Although there are no guarantees, we generally have been successful in renewing or extending contracts in the past. For the year ended December 31, 2013, over 70% of all the coal we produced from continuing operations was sold under contracts with terms of one year or more.

The following table sets forth as of January 22, 2014, CONSOL Energy's estimated production and sales for 2014 through 2015.

21

COAL DIVISION GUIDANCE
(Tons in millions)

	Q1 2014	2014	2015
Est. Total Coal Sales	7.2 - 7.6	30.1 - 32.1	34.0
Tonnage: Firm	6.9	23.8	12.2
Price: Sold (firm)	$64.75	$65.35	$69.23
Est. Low-Vol Met Sales	1.1 - 1.2	4.2 - 4.7	4.9
Tonnage: Firm	0.8	1.7	0.8
Est. High-Vol Met Sales	0.7+	2.3+	2.4
Tonnage: Firm	0.6	0.9	0.3
Est. Thermal Sales	5.6+	23.8+	26.7
Tonnage: Firm	5.5	21.2	11.1

Note: While most of the data in the table are single point estimates, the inherent uncertainty of markets and mining operations means that investors should consider a reasonable range around these estimates. CONSOL Energy has chosen not to forecast prices for open tonnage due to ongoing customer negotiations. Firm tonnage is tonnage that is both sold and priced, and excludes collared tons. There are no collared tons in 2014. Collared tons in 2015 are 1.4 million tons, with a ceiling of $72.59 per ton and a floor of $48.59 per ton. Not included in the category breakdowns are the tons from equity affiliates Harrison Resources and Western Allegheny Energy (WAE). Harrison Resources has 0.1 million tons for Q1 2014, and 0.4 million tons for all of 2014 and 2015. WAE has 0.1 million tons for Q1 2014, and 0.5 million tons and 0.9 million tons for all of 2014, and 2015, respectively.

Coal pricing for contracts with terms of one year or less is generally fixed. Coal pricing for multiple-year agreements generally provide the opportunity to periodically adjust the contract prices through pricing mechanisms consisting of one or more of the following:

- Fixed price contracts with pre-established prices;
- Periodically negotiated prices that reflect market conditions at the time;
- Price restricted to an agreed-upon percentage increase or decrease; or
- Base-price-plus-escalation methods which allow for periodic price adjustments based on inflation indices, or other negotiated indices.

The volume of coal to be delivered is specified in each of our coal contracts. Although the volume to be delivered under the coal contracts is stipulated, the parties may vary the timing of the deliveries within specified limits.

Coal contracts typically contain force majeure provisions allowing for the suspension of performance by either party for the duration of specified events. Force majeure events include, but are not limited to, unexpected significant geological conditions or natural disasters. Depending on the language of the contract, some contracts may terminate upon continuance of an event of force majeure that extends for a period greater than three to twelve months.

Distribution

Coal is transported from CONSOL Energy's mining complexes to customers by railroad cars, trucks or a combination of these means of transportation. We employ transportation specialists who negotiate freight and equipment agreements with various transportation suppliers, including railroads, barge lines, terminal operators, ocean vessel brokers and trucking companies for certain customers.

Coal Competition

The United States coal industry is highly competitive, with numerous producers selling into all markets that use coal. CONSOL Energy competes against several other large producers and numerous small producers in the United States and overseas. Demand for our coal by our principal customers is affected by many factors including:

- the price of competing coal and alternative fuel supplies, including nuclear, natural gas, oil and renewable energy sources, such as hydroelectric power, wind or solar;
- environmental and government regulation;
- coal quality;

- transportation costs from the mine to the customer;
- the reliability of fuel supply;
- worldwide demand for steel;
- natural/weather disasters; and
- political changes in international governments.

Continued demand for CONSOL Energy's coal and the prices that CONSOL Energy obtains are affected by demand for electricity, technological developments, environmental and governmental regulation, and the availability and price of competing coal and alternative fuel supplies. We sell coal to foreign electricity generators and to the more specialized metallurgical coal markets, both of which are significantly affected by international demand and competition.

Other Operations

CONSOL Energy provides other services both to our own operations and to others. These include land services, industrial supply services, terminal services and water services.

Non-Core Mineral Assets and Surface Properties

CONSOL Energy owns significant gas and coal assets that are not in our short or medium term development plans. We continually explore the monetization of these non-core assets by means of sale, lease, contribution to joint ventures, or a combination of the foregoing in order to bring the value of these assets forward for the benefit of our shareholders. We also control a significant amount of surface acreage. This surface acreage is valuable to us in the development of the gathering system for our Marcellus Shale and Utica Shale production. We also derive value from this surface control by granting rights of way or development rights to third parties when we are able to derive appropriate value for our shareholders.

Industrial Supply Services

Fairmont Supply Company, a CONSOL Energy subsidiary, is a general-line distributor of mining, drilling, and industrial supplies in the United States. Fairmont Supply has 27 customer service centers nationwide. Fairmont Supply also provides integrated supply procurement and management services. Integrated supply procurement is a materials management strategy that utilizes a single, full-line distribution to minimize total cost in the maintenance, repair and operating supply chain.

Fairmont Supply provides mine and drilling supplies to CONSOL Energy's mining and gas operations. CONSOL Energy's coal and gas divisions accounted for 37% of Fairmont Supply's sales in 2013.

Terminal Services

In 2013, approximately 10.2 million tons of coal were shipped through CONSOL Energy's subsidiary, CNX Marine Terminals Inc.'s, exporting terminal in the Port of Baltimore. Approximately 21% of the tonnage shipped was produced by CONSOL Energy coal mines. The terminal can either store coal or load coal directly into vessels from rail cars. It is also one of the few terminals in the United States served by two railroads, Norfolk Southern Corporation and CSX Transportation Inc.

Water Services

CNX Water Assets LLC, a CONSOL Energy subsidiary, is acquiring and developing existing sources of water in order to support our gas and coal operations, develop business in water sales, promote cutting edge water technologies, treat both acid mine drainage (AMD) water and fracturing water, and reduce our environmental liabilities. CNX Water Assets' operate an advanced waste water treatment plant in support of coal operations as well as fresh water reservoirs. CNX Water Assets' objective is to develop and maximize the value of existing water assets, which will be used to provide water for drilling and hydraulic fracturing in support of gas operations and meeting the needs of mining operations. CNX Water Assets' also has contracts to provide water to third parties for industrial use from various water sources owned by CONSOL Energy.

Employee and Labor Relations

At December 31, 2013, CONSOL Energy had 4,633 employees. Less than 1% of the total workforce is represented by the United Mine Workers of America (UMWA).

Industry Segments

Financial information concerning industry segments, as defined by accounting principles generally accepted in the United States, for the years ended December 31, 2013, 2012 and 2011 is included in Note 25 - Segment Information in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K and incorporated herein.

Laws and Regulations

Overview

Our gas and coal mining operations are subject to various types of federal, state and local regulations. Regulations relating to our operations include permitting and other licensing requirements; water withdrawal and procurement for well stimulation purposes; well drilling and casing; well production; well plugging; venting or flaring of natural gas; pipeline compression and transmission of natural gas and liquids; reclamation and restoration of properties after gas or mining operations are completed; storage, transportation and disposal of materials used or generated by gas and mining operations; the calculation, reporting and disbursement of taxes; gathering of gas production in certain circumstances; surface subsidence from underground mining; discharge of water from coal mining operations; air quality standards; protection of wetlands; endangered plant and wildlife protection; and employee health and safety. Numerous governmental permits and approvals under these laws and regulations are required for gas and mining operations. Lastly, the electric power generation industry is subject to extensive regulation regarding the environmental impact of its power generation activities, which could affect demand for our gas and coal products.

Compliance with these laws has substantially increased the cost of gas production and mining of coal for all domestic gas and coal producers. We also post performance bonds or letters of credit pursuant to state oil and gas laws and regulations to guarantee reclamation of gas well sites and plugging of gas wells. We post surety performance bonds or letters of credit pursuant to federal and state mining laws and regulations for the estimated costs of reclamation and mine closing, often including the cost of treating mine water discharge. We endeavor to conduct our gas and mining operations in compliance with all applicable federal, state and local laws and regulations. However, because of extensive and comprehensive regulatory requirements against a backdrop of variable geologic and seasonal conditions, permit exceedances and violations during gas and mining operations can and do occur. The possibility exists that new legislation or regulations may be adopted which would have a significant impact on our gas and coal mining operations or our customers' ability to use our gas and coal and may require us or our customers to change their operations significantly or incur substantial costs.

CONSOL Energy made capital expenditures for environmental control facilities of approximately $1.6 million, $1.3 million, and $4.2 million in the years ended December 31, 2013, 2012 and 2011, respectively. CONSOL Energy expects to have capital expenditures of $9.9 million in 2014 for environmental control facilities.

Environmental Laws

Clean Air Act and Related Regulations. The federal Clean Air Act and similar state laws and regulations which regulate emissions into the air, affect gas production and processing operations, as well as coal mining, coal handling and processing, primarily through permitting and/or emissions control requirements.

We are required to obtain pre-approval for construction or modification of certain facilities, to meet stringent air permit requirements, or to use specific equipment, technologies or best management practices to control emissions. On August 16, 2012, the U.S. Environmental Protection Agency (EPA) published final revisions to the New Source Performance Standards (NSPS) to regulate emissions of volatile organic compounds (VOCs) and sulfur dioxide (SO2) from various oil and gas exploration, production, processing and transportation facilities and revisions to the National

Emission Standards for Hazardous Air Pollutants (NESHAPS) to further regulate emissions from the oil and natural gas production sector and the transmission and storage of natural gas. In September 2009, the EPA finalized the Mandatory Reporting of Greenhouse Gas Rule. The current version of this rule requires annual reporting of emissions from gas wells, coal mines and associated facilities.

The Clean Air Act also indirectly and more significantly affects the U.S. coal industry by extensively regulating the air emissions of the coal fired electric power generating plants operated by our customers. Coal contains impurities, such as sulfur, mercury and other constituents, many of which are released into the air when coal is burned. Carbon dioxide, a greenhouse gas, is also emitted when coal is burned. Environmental regulations governing emissions from coal fired electric generating plants could affect demand for coal as a fuel source and affect the volume of our sales. In 2012, the EPA promulgated or finalized several rulemakings impacting coal generating facilities. Two of these were final rules for new source performance standards for coal and oil fueled power plants in the Utility Maximum Control Technology (UMACT) rule which includes more stringent new source performance standards (NSPS) for particulate matter (PM), SO 2 and NO X and the Mercury and Air Toxics Standards (MATS) rule which sets new mercury and air toxic standards. In November 2012, EPA published a notice of reconsideration of certain aspects of the UMACT and MATS rules. In April 2013, EPA issued a final version of its reconsideration of its UMACT and MATS rules. The reconsideration resulted in higher limits, but the standards are still stringent and compliance will be expensive. In addition, in August 2012, the U.S. Court of Appeals in Washington, DC invalidated EPA's 2011 Cross-State Air Pollution Rule which was intended to regulate sulfur dioxide (SO2), nitrogen dioxide (NOx) and fine particulate matter. The Court ruled that the agency had overstepped its bounds and vacated the rulemaking, ordering the agency to continue to enforce the Clean Air Interstate Rule promulgated in 2005 until a viable replacement to the cross-state regulation could be issued. An appeal from the Circuit Court’s decision was argued before the U.S. Supreme Court in December 2013.

In April 2012, the EPA published its proposed New Source Performance Standards (NSPS) for carbon dioxide emissions from coal powered electric generating units. The proposed rules would have applied to new power plants and to existing plants that make major modifications. If the rules had been adopted as proposed, the only new coal fired power plants that could have met the proposed emission limits would have been coal fired plants with carbon dioxide capture and storage (CCS). Commercial scale CCS is not likely to be available in the near future, and if available, it may make coal fired electric generation units uneconomical compared to new gas fired electric generation units. On January 8, 2014, EPA re-proposed NSPS for CO2 for new fossil fuel fired power plants and rescinded the rules that were proposed on April 12, 2012. These proposed rules will also require CCS for new coal fired power plants.

Clean Water Act. The federal Clean Water Act (CWA) and corresponding state laws affect our gas and coal operations by regulating discharges into surface waters. Permits requiring regular monitoring and compliance with effluent limitations and reporting requirements govern the discharge of pollutants into regulated waters. The Clean Water Act and corresponding state laws include requirements for: improvement of designated "impaired waters" (not meeting state water quality standards) through the use of effluent limitations; anti-degradation regulations which protect state designated "high quality/exceptional use" streams by restricting or prohibiting discharges; requirements to treat discharges from coal mining properties for non-traditional pollutants, such as chlorides, selenium and dissolved solids; for minimizing impacts and compensating for unavoidable impacts resulting from discharges of fill materials to regulated streams and wetlands; and the requirements to dispose of produced wastes and other oil and gas wastes at approved disposal facilities. In addition, the Spill Prevention, Control and Countermeasure (SPCC) requirements of the CWA apply to all CONSOL Energy operations that use or produce fluids, including brine and oil, and require that plans be in place to address any spills and that secondary containment be installed around all tanks. These requirements may cause CONSOL Energy to incur significant additional costs that could adversely affect our operating results, financial condition and cash flows.

Pursuant to a Congressional requirement in the EPA's 2010 budget appropriation, the EPA must conduct a comprehensive study of the potential adverse impact that hydraulic fracturing may have on water quality and public health. Hydraulic fracturing is a way of producing gas from tight rock formations such as the Marcellus and Utica shales. The EPA initiated the study in early January 2011 with a final report to be published in 2014. In 2012, EPA has also announced plans to conduct a review of water produced in conjunction with the production of Coal Bed Methane (CBM) to determine whether its disposal should be further regulated. In late 2013, EPA announced that it did not intend to continue with its effort to revise effluent limits for coalbed methane operations.

CONSOL Energy utilizes pipelines extensively for its gas, water and coal businesses, and as such must obtain permits with associated mitigation from the Army Corps of Engineers (ACOE) for impacts to streams and wetlands that we are unable to avoid. In 2013, the EPA issued a draft report entitled Connectivity of Streams and Wetlands to Downstream Waters which affects a proposed rulemaking that would expand the scope of the Clean Water Act

(CWA) to include previously non-jurisdictional streams, wetlands, and waters and make these areas jurisdictional inter-coastal Waters of the U.S. This rulemaking will likely cause states that have jurisdiction over their own waters to make regulatory changes to their already robust regulatory programs offering little to no added environmental protection or benefit from the changes. This would only add unwarranted delays to the permitting process and extend review times even further for regulatory agencies already under resourced.

In order to obtain a permit for surface coal mining activities, including valley fills associated with steep slope mining, an operator must obtain a permit for the discharge of fill material from the ACOE and a discharge permit from the state regulatory authority under the state counterpart to the Clean Water Act. Beginning in early 2009, the EPA took a number of initiatives that have resulted in delays and obstruction of the issuance of such permits for surface mining operation in the Appalachian states including Pennsylvania and Virginia where our principal mining complexes are located. Increased oversight of delegated state programmatic authority, coupled with individual permit review and additional requirements imposed by the EPA, has resulted in delays in the review and issuance of permits for surface coal mining operations, including applications for surface facilities for underground mines, such as applications for coal refuse disposal areas. The coal industry has had some success challenging EPA’s policies but EPA continues with its initiatives. Thus far, CONSOL Energy subsidiaries have been able to continue operating their existing mines. There is no assurance that permits can be obtained for future mining operations.

In late June 2012, we received informal notification from the Pennsylvania Department of Environmental Protection of the Department's intent pursuant to a Technical Guidance Document entitled “Surface Water Protection-Underground Bituminous Coal Mining” to require a change in the mine plan of a pending application for a permit for expansion of the Company's Bailey longwall mine. If ultimately required, this change in mine plan could have a material effect on our forecasted production for 2015. We do not agree that a modification of its mining plan is necessary to comply with applicable regulatory performance standards and we continue to submit information to the permitting authority to support our position. Additionally, we are currently evaluating potential modifications that would be required if we are compelled to modify our application.

Comprehensive Environmental Response, Compensation and Liability Act (Superfund). The Comprehensive Environmental Response, Compensation and Liability Act (Superfund) and similar state laws create liabilities for the investigation and remediation of releases of hazardous substances into the environment and for damages to natural resources. We could incur liability under CERCLA relative to our gas or coal operations. We also must comply with reporting requirements under the Emergency Planning and Community Right-to-Know Act and the Toxic Substances Control Act.

Resource Conservation and Recovery Act. The federal Resource Conservation and Recovery Act (RCRA) and corresponding state laws and regulations affect gas operations and coal mining by imposing requirements for the treatment, storage and disposal of hazardous wastes. Facilities at which hazardous wastes have been treated, stored or disposed are subject to corrective action orders issued by the EPA which could adversely affect our results, financial condition and cash flows. In 2010, the EPA proposed options for the regulation of Coal Combustion Residuals from the electric power sector as either hazardous waste or non-hazardous waste. A final decision is expected in 2014. Depending on the outcome of that decision, demand for coal fired electricity generation could be adversely impacted.

Endangered Species Act. The Federal Endangered Species Act (ESA) and similar state laws protect species threatened with extinction. Protection of endangered and threatened species may cause us to modify gas well pad siting or pipeline right of ways, mining plans, or develop and implement species-specific protection and enhancement plans to avoid or minimize impacts to endangered species or their habitats. A number of species indigenous to the areas where we operate are protected under the ESA. Based on the species that have been identified and the current application of endangered species laws and regulations, we do not believe that there are any species protected under the ESA or state laws that would materially and adversely affect our ability to produce gas or mine coal from our properties. The US Fish and Wildlife Service (USFWS) announced a 12-month finding that listing of the Northern Long-Eared Bat as endangered is warranted throughout the bat’s range. CONSOL Energy, along with others in industry have submitted comments against the listing. This listing will establish habitat protection for the species but will not prevent the cause of the decline in the population of the Long-Eared bat, which is due to a disease commonly referred to as White Nose Syndrome. This will lead to significant timing and critical path hurdles, ultimately limiting the ability to clear timber for construction activities.

Surface Mining Control and Reclamation Act. The federal Surface Mining Control and Reclamation Act (SMCRA) establishes minimum national operational, reclamation and reclamation standards for all surface mines as well as most aspects of underground mines. SMCRA requires that comprehensive environmental protection and reclamation standards be met during the course of and following completion of mining activities. Permits for all mining operations must be obtained from the U. S. Office of Surface Mining (OSM) or, where state regulatory agencies have adopted federally approved state programs under SMCRA, the appropriate state regulatory authority. States that operate federally approved state programs may impose standards which are more stringent than the requirements of SMCRA and OSM's regulations and in many instances have done so. Our active mining complexes are located in states which have achieved primary jurisdiction for enforcement of SMCRA through approved state programs. In addition, SMCRA imposes a reclamation fee on all current mining operations, the proceeds of which are deposited in the Abandoned Mine Reclamation Fund (AML Fund), which is used to restore unreclaimed and abandoned mine lands mined before 1977. The current per ton fee is $0.280 per ton for surface mined coal and $0.120 per ton for underground mined coal. These fees are currently scheduled to be in effect until September 30, 2021.

OSM is currently considering modifications to the existing stream buffer zone regulation, which amendments are referred to as the Stream Protection Rule. OSM’s latest position is that proposed Stream Protection regulations will be published in August 2014. Although it is too early to predict what the impacts of the proposed amendments will be, they could result in loss of access to significant amounts of coal and/or significant increases in reclamation costs. In Pennsylvania, where we operate two longwall mines, approximately $16.0 million, $21.1 million and $25.7 million of expenses were incurred from continuing operations during the years ended December 31, 2013, 2012 and 2011, respectively, to mitigate and repair impacts on streams from subsidence. We currently estimate expenses related to subsidence of streams in Pennsylvania will be approximately $15.8 million for the year ended December 31, 2014.

Federal Regulation of the Sale and Transportation of Gas

Regulations and orders set forth by the Federal Energy Regulatory Commission (FERC) impact our gas business to a certain degree. Although the FERC does not directly regulate our gas production activities, the FERC has stated that it intends for certain of its orders to foster increased competition within all phases of the natural gas industry. Additionally, the FERC continues to review its transportation regulations, including whether to allocate all short-term capacity on the basis of competitive auctions and whether changes to its long-term transportation policies may also be appropriate to avoid a market bias toward short-term contracts. The FERC has also issued numerous orders confirming the sale and abandonment of natural gas gathering facilities previously owned by interstate pipelines and acknowledging that if the FERC does not have jurisdiction over services provided by these facilities, then such facilities and services may be subject to regulation by state authorities in accordance with state law. We own certain natural gas pipeline facilities that we believe meet the traditional tests which the FERC has used to establish a pipeline's status as a gatherer not subject to the FERC jurisdiction.

Health and Safety Laws

Occupational Safety and Health Act. Our gas operations are subject to regulation under the federal Occupational Safety and Health Act (OSHA) and comparable state laws in some states, all of which regulate health and safety of employees at our gas operations. Also, OSHA's hazardous communication standard requires that information be maintained about hazardous materials used or produced by our gas operations and that this information be provided to employees, state and local governments and the public.

Mine Safety. Legislative and regulatory changes have required us to purchase additional safety equipment, construct stronger seals to isolate mined out areas, and engage in additional training. We have also experienced more aggressive inspection protocols and with new regulations the amount of civil penalties have increased. The actions taken thus far by federal and state governments include requiring:

- the caching of additional supplies of self-contained self-rescuer (SCSR) devices underground;
- the purchase and installation of electronic communication and personal tracking devices underground;
- the placement of refuge chambers, which are structures designed to provide refuge for groups of miners during a mine emergency when evacuation from the mine is not possible, which will provide breathable air for 96 hours;
- the replacement of existing seals in worked-out areas of mines with stronger seals;
- the purchase of new fire resistant conveyor belting underground;
- additional training and testing that creates the need to hire additional employees; and
- more stringent rock dusting requirements.

According to a November 2013 regulatory update, in the first quarter of 2014 the Department of Labor intends to publish final rules for underground coal mining operations concerning lowering coal miners exposure to respirable coal mine dust and concerning proximity detection systems for continuous mining machines. Proposed rules for concerning exposure of coal miners to crystalline silica and proximity detection systems for mobile machines in underground mines are intended to be published in the second quarter of 2014.

Black Lung Legislation. Under federal black lung benefits legislation, each coal mine operator is required to make payments of black lung benefits or contributions to:

- current and former coal miners totally disabled from black lung disease;

- certain survivors of a miner who dies from black lung disease or pneumoconiosis; and
- a trust fund for the payment of benefits and medical expenses to claimants whose last mine employment was before January 1, 1970, where no responsible coal mine operator has been identified for claims (where a miner's last coal employment was after December 31, 1969), or where the responsible coal mine operator has defaulted on the payment of such benefits. The trust fund is funded by an excise tax on U.S. production of up to $1.10 per ton for deep mined coal and up to $0.55 per ton for surface-mined coal, neither amount to exceed 4.4% of the gross sales price.

The Patient Protection and Affordable Care Act (PPACA) made two changes to the Federal Black Lung Benefits Act. First, it provided changes to the legal criteria used to assess and award claims by creating a legal presumption that miners are entitled to benefits if they have worked at least 15 years in underground coal mines, or in similar conditions, and suffer from a totally disabling lung disease. To rebut this presumption, a coal company would have to prove that a miner did not have black lung or that the disease was not caused by the miner's work. Second, it changed the law so black lung benefits will continue to be paid to dependent survivors when the miner passes away, regardless of the cause of the miner's death. In addition to the federal legislation, we are also liable under various state statutes for black lung claims.

Other State and Local Laws Related to Our Gas Business

Regulation Affecting Gas Operations. Our gas operations are also subject to regulation at the state and in some cases, county, municipal and local governmental levels. Such regulation includes requiring permits for the siting and construction of well pads and roads, drilling of wells, bonding requirements, protection of ground water and surface water resources and protection of drinking water supplies, the method of drilling and casing wells, the surface use and restoration of well sites, gas flaring, the plugging and abandoning of wells, the disposal of fluids used in connection with operations, and gas operations producing coalbed methane in relation to active mining. A number of states have either enacted new laws or may be considering the adequacy of existing laws affecting gathering rates and/or services. Other state regulation of gathering facilities generally includes various safety, environmental and in some circumstances, nondiscriminatory take requirements, but does not generally entail rate regulation. Thus, natural gas gathering may receive greater regulatory scrutiny of state agencies in the future. Our gathering operations could be adversely affected should they be subject in the future to increased state regulation of rates or services, although we do not believe that they would be affected by such regulation any differently than other natural gas producers or gatherers. However, these regulatory burdens may affect profitability, and we are unable to predict the future cost or impact of complying with such regulations.

Ownership of Mineral Rights. CONSOL Energy acquires ownership or leasehold rights to gas and coal properties prior to conducting operations on those properties. As is customary in the gas and coal industries, we have generally conducted only a summary review of the title to gas and coal rights that are not in our development plans, but which we believe we control. This summary review is conducted at the time of acquisition or as part of a review of our land records to determine control of mineral rights. Given CONSOL Energy's long history as a coal producer, we believe we have a well-developed ownership position relating to our coal control; however, our ownership of oil and gas rights, particularly those rights that we acquired in connection with our historic coal operations and some of the rights we acquired in 2010 from Dominion are less developed. As we continue to review our land records and confirm title in anticipation of development, we expect that adjustments to our ownership position (either increases or decreases) will be required.

Prior to the commencement of development operations on gas and coal properties, we conduct a thorough title examination and perform curative work with respect to significant defects. We generally will not commence operations on a property until we have cured any material title defects on such property. We are typically responsible for the cost of curing any title defects. In addition, the acquisition of the necessary rights may not be feasible in some cases. Our discovering gas title defects which we are unable to cure may adversely impact our ability to develop those properties and we may have to reduce our estimated gas reserves including our proved undeveloped reserves. We have completed title work on substantially all of our gas and coal producing properties and believe that we have satisfactory title to our producing properties in accordance with standards generally accepted in the industry.

Available Information

CONSOL Energy maintains a website on the World Wide Web at www.consolenergy.com. CONSOL Energy makes available, free of charge, on this website our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended (the 1934 Act), as soon as reasonably practicable after such reports are available, electronically filed with, or furnished to the SEC, and are also available at the SEC's website www.sec.gov.

Executive Officers of the Registrant

Incorporated by reference into this Part I is the information set forth in Part III, Item 10 under the caption "Directors and Executive Officers of CONSOL Energy" (included herein pursuant to Item 401 (b) of Regulation S-K).

ITEM 1A. Risk Factors

Investment in our securities is subject to various risks, including risks and uncertainties inherent in our business. The following sets forth factors related to our business, operations, financial position or future financial performance or cash flows which could cause an investment in our securities to decline and result in a loss.

Deterioration in the global economic conditions in any of the industries in which our customers operate, or a worldwide financial downturn, such as the 2008 - 2009 financial crisis, or negative credit market conditions may have lasting effects on our liquidity, business and financial condition that we cannot predict.

Economic conditions in a number of industries in which our customers operate, such as electric power generation and steel making, substantially deteriorated in recent years and reduced the demand for natural gas and coal. Although global industrial activity recovered from 2009 levels, the general economic challenges continued in 2013 and the outlook is uncertain. In addition, liquidity is essential to our business. Although we cannot predict the impacts, renewed weakness in the economic conditions of any of the industries we serve, or another financial crisis, could adversely affect our business and financial condition in a number of ways. For example:

- demand for natural gas and electricity in the United States is impacted by industrial production, which if weakened would negatively impact the revenues, margins and profitability of our natural gas and thermal coal business;
- demand for metallurgical coal depends on steel demand in the United States and globally, which if weakened would negatively impact the revenues, margins and profitability of our metallurgical coal business including our ability to sell our thermal coal as higher-priced high volatile metallurgical coal;
- the tightening of credit or lack of credit availability to our customers could adversely affect our ability to collect our trade receivables and the amount of receivables eligible for sale pursuant to our accounts receivable securitization facility may decline;
- our ability to access the capital markets may be restricted at a time when we would like, or need, to raise capital for our business including for exploration and/or development of our gas or coal reserves; and
- our commodity hedging arrangements could become ineffective if our counterparties are unable to perform their obligations or seek bankruptcy protection.

An extended decline in demand for our products, or the prices CONSOL Energy receives for natural gas, natural gas liquids, and coal will adversely affect our operating results and cash flows.

Our financial results are significantly affected by the demand for our products and the prices we receive for our natural gas, natural gas liquids, and coal.

Natural gas and natural gas liquids accounted for approximately 26% of our revenues from continuing operations in 2013. Natural gas prices are very volatile, and even relatively modest drops in prices can significantly affect our financial results and impede growth. Prices for natural gas may fluctuate widely in response to relatively minor changes in the supply of and demand for natural gas, market uncertainty and a variety of additional factors that are beyond our control, such as:

- the overall domestic supply of natural gas;
- the supply of natural gas in our market;
- changes in the consumption pattern of industrial consumers, electricity generators and residential users;
- weather conditions;
- proximity and capacity of gas pipelines and other transportation facilities;
- overall domestic and global economic conditions;

- the price and availability of alternative fuels, especially thermal coal; and
- the price and supply of imported liquefied natural gas.

In particular, while demand for natural gas has recovered to pre-recession levels, the U.S. natural gas industry continues to face concerns of oversupply due to the success of Marcellus and other new shale plays. The oversupply of natural gas in 2012 resulted in domestic prices hovering around ten year lows, and drilling continued in these plays, despite lower gas prices, to meet drilling commitments. Our gas operations are geographically concentrated in the mid-Atlantic states and oversupply from the continued drilling in these plays, despite lower prices, directly affects prices we receive. Low gas prices adversely impacts our gas operations revenues and earnings before income taxes.

The success of the Marcellus Shale play and development of other Shale plays has resulted in growth in gas production in this region with production per day in Pennsylvania, West Virginia and Ohio more than doubling since 2011. Traditionally, natural gas produced in the mid-Atlantic states sold at a premium to the benchmark Louisiana Henry Hub prices. However, as Appalachian production increased this premium narrowed. This decline, or negative basis, to the Henry Hub price is forecasted to continue in future years and may widen due to anticipated further increased Appalachian gas production. Thus, apart from the general impact of domestic production on overall gas prices, the price paid for our natural gas also may be adversely affected by increasing production in our market.

An extended period of lower natural gas prices could negatively affect us in several other ways. These include reduced cash flow, which would decrease funds available for capital expenditures employed to replace reserves or increase production. For example, in light of the low natural gas prices during 2012, the number of wells drilled in our Noble joint venture during 2012 was significantly reduced from the number we initially planned to drill. Also, our access to other sources of capital, such as equity or long-term debt markets, could be severely limited or unavailable. Additionally, lower natural gas prices may reduce the amount of natural gas that we can produce economically. This may result in our having to make substantial downward adjustments to our estimated proved reserves. If this occurs, or if our estimates of development costs increase, production data factors change or our exploration results deteriorate, accounting rules may require us to write down, as a non-cash charge to earnings, the carrying value of our natural gas properties. We are required to perform impairment tests on our assets whenever events or changes in circumstances lead to a reduction of the estimated useful life or estimated future cash flows that would indicate that the carrying amount may not be recoverable or whenever management's plans change with respect to those assets. We may incur impairment charges in the future, which could have an adverse effect on our results of operations in the period taken.

We and our joint venture partners have increased drilling activity in areas of shale formations which may also contain natural gas liquids and/or oil. The prices for natural gas liquids and oil are volatile for reasons similar to those described above regarding natural gas. Similar to the oversupply of natural gas, increased drilling activity in 2012 by third parties in formations containing natural gas liquids has led to a significant decline in the price of natural gas liquids. If we discover and produce significant amounts of natural gas liquids or oil, our results of operation may be adversely affected by downward fluctuations in natural gas liquids and oil prices.

The sale to Murray Energy in 2013 of almost one half or our thermal coal production increased our exposure to fluctuations in the price of coal, natural gas and natural gas liquids.

Coal accounted for approximately 66% of our revenues from continuing operations in 2013. Prices of and demand for our coal may fluctuate due to factors beyond our control such as:

- overall domestic and global economic conditions, technological advances affecting energy consumption, price and availability of foreign coal, and domestic and foreign government regulations;
- the consumption pattern of industrial consumers, electricity generators and residential users;
- weather can impact thermal coal demand (for example, the unusually warm 2011 - 2012 winter left utilities with large coal stockpiles and depressed the demand for thermal coal);
- the price and availability of alternative fuels for electricity generation, especially natural gas (for example, abundant natural gas supplies at prices averaging less than $3/MMbtu during 2012 depressed the demand for thermal coal as natural gas fired electricity generation market share increased from approximately 25% in 2011 to 30% in 2012 and coal-fired generation declined from approximately 42% in 2011 to 37% in 2012); and
- increased utilization by the steel industry of electric arc furnaces or pulverized coal processes to make steel which do not use furnace coke, an intermediate product produced from metallurgical coal, decreases the demand for metallurgical coal.

Decreased demand and extended or substantial price declines for coal adversely affect our operating results for future periods and our ability to generate cash flows necessary to improve productivity and expand operations. For example, in 2012 domestic and global economic deterioration, unusually warm winter weather and abundant cheap natural gas decreased demand for our coal as well as decreased the average sales price for our metallurgical coal and resulted in our coal revenues and earnings before income taxes significantly declining from 2011. In 2013, our average sales price per ton of low volatile metallurgical coal fell by approximately 34% due to oversupply which was particularly acute in the international market.

If coal customers do not extend existing contracts or do not enter into new long-term coal contracts, profitability of CONSOL Energy's operations could be affected.

During the year ended December 31, 2013, approximately 70% of the coal CONSOL Energy produced from continued operations was sold under long-term contracts (contracts with terms of one year or more). If a substantial portion of CONSOL Energy's long-term contracts are modified or terminated or if force majeure is exercised, CONSOL Energy would be adversely affected if we are unable to replace the contracts or if new contracts are not at the same level of profitability. If existing customers do not honor current contract commitments, our revenue would be adversely affected. The profitability of our long-term coal supply contracts depends on a variety of factors, which vary from contract to contract and fluctuate during the contract term, including our production costs and other factors. Price changes, if any, provided in long-term supply contracts may not reflect our cost increases, and therefore, increases in our costs may reduce our profit margins. In addition, in periods of declining market prices, provisions in our long-term coal contracts for adjustment or renegotiation of prices and other provisions may increase our exposure to short-term coal price volatility. As a result, CONSOL Energy may not be able to obtain long-term agreements at favorable prices compared to either market conditions, as they may change from time to time, or our cost structure, and long-term contracts may not contribute to our profitability.

The loss of, or significant reduction in, purchases by our largest coal customers could adversely affect our revenues.

For the year ended December 31, 2013, we derived over 10% of our total revenues from sales to two coal customers individually and more than 35% of our total revenue from sales to our four largest coal and gas customers. At December 31, 2013, we had approximately twenty-four coal supply agreements with these customers that expire at various times from 2014 to 2028. We are currently discussing the extension of existing agreements or entering into new long-term agreements with some of these customers, but these negotiations may not be successful and these customers may not continue to purchase coal from us under long-term coal supply agreements. If any one of these customers were to significantly reduce their purchases of coal from us, or if we were unable to sell coal to them on terms as favorable to us as the terms under our current agreements, our financial condition and results of operations could suffer.

Our ability to collect payments from our customers could be impaired if their creditworthiness declines or if they fail to honor their contracts with us.

Our ability to receive payment for natural gas and coal sold and delivered depends on the continued creditworthiness of our customers. Some power plant owners may have credit ratings that are below investment grade. If the creditworthiness of our customers declines significantly, our $200 million accounts receivable securitization program and our business could be adversely affected. In addition, if customers refuse to accept shipments of our coal for which they have an existing contractual obligation, our revenues will decrease and we may have to reduce production at our mines until our customer's contractual obligations are honored.

Our gas business depends on gathering, processing and transportation facilities owned by others and the disruption of, capacity constraints in, or proximity to pipeline systems could limit sales of our natural gas. Similarly, the availability and reliability of transportation facilities and fluctuations in transportation costs could affect the demand for our coal or impair our ability to supply coal to our customers.

We gather, process and transport our gas to market by utilizing pipelines and facilities owned by others. If pipeline or facility capacity is limited, or if pipeline or facility capacity is unexpectedly disrupted, our gas sales and/or sales of natural gas liquids could be limited, reducing our profitability. If we cannot access processing pipeline transportation facilities, we may have to reduce our production of gas or vent our produced gas to the atmosphere because we do not have facilities to store excess inventory. If our sales of gas or natural gas liquids are reduced because of transportation or processing constraints, our revenues will be reduced, and our unit costs will also increase. If pipeline quality tariffs change, we might be required to install additional processing equipment which could increase our costs. The pipeline could also curtail our flows until the gas delivered to their pipeline is in compliance.

Coal producers depend upon rail, barge, trucking, overland conveyor and other systems to provide access to markets. Disruption of transportation services because of weather-related problems, strikes, lock-outs, or other events could temporarily impair our ability to supply coal to customers and adversely affect our profitability. Transportation costs represent a significant portion of the delivered cost of coal and, as a result, the cost of delivery is a critical factor in a customer's purchasing decision. Increases in transportation costs could make our coal less competitive.

Competition within the natural gas and coal industries may adversely affect our ability to sell our products. Increased competition or a loss of our competitive position could adversely affect our sales of, or our prices for, our natural gas and coal products, which could impair our profitability.

The gas industry is intensely competitive with companies from various regions of the United States. We compete with these companies and we may compete with foreign companies for domestic sales. Many of the companies we compete with are larger and have greater financial, technological, human and other resources. If we are unable to compete, our company, our operating results and financial position may be adversely affected. In addition, larger companies may be able to pay more to acquire new gas properties for future exploration, limiting our ability to replace natural gas we produce or to grow our production. Our ability to acquire additional properties and to discover new natural gas resources also depends on our ability to evaluate and select suitable properties and to consummate these transactions in a highly competitive environment.

CONSOL Energy competes with coal producers in various regions of the United States and with some foreign coal producers for domestic sales primarily to electric power generators. CONSOL Energy also competes with both domestic and foreign coal producers for sales in international markets. Demand for our coal by our principal customers is affected by the delivered price of competing coals, other fuel supplies and alternative generating sources, including nuclear, natural gas, oil and renewable energy sources, such as hydroelectric and wind power. CONSOL Energy sells coal to foreign electricity generators and to the more specialized metallurgical coal market, both of which are significantly affected by international demand and competition. Increases in coal prices could encourage existing producers to expand capacity or could encourage new producers to enter the market. If overcapacity results, prices could fall or we may not be able to sell our coal, which would reduce revenue.

The characteristics of coal may make it costly for electric power generators and other coal users to comply with various environmental standards regarding the emissions of impurities released when coal is burned which could cause utilities to replace coal-fired power plants with alternative fuels. In addition, various incentives have been proposed to encourage the generation of electricity from renewable energy sources. A reduction in the use of coal for electric power generation could decrease the volume of our domestic coal sales and adversely affect our results of operations.

Coal contains impurities, including sulfur, mercury, chlorine and other elements or compounds, many of which are released into the air along with fine particulate matter and carbon dioxide when coal is burned. Complying with regulations on these emissions can be costly for electric power generators. For example, in order to meet the federal Clean Air Act limits for sulfur dioxide emissions from electric power plants, coal users will need to install scrubbers, use sulfur dioxide emission allowances (some of which they may purchase), or switch to other fuels. Each option has limitations. Lower sulfur coal may be more costly to purchase on an energy basis than higher sulfur coal depending on mining and transportation costs. The cost of installing scrubbers is significant and emission allowances may become more expensive as their availability declines. Switching to other fuels may require expensive modification of existing plants. Because higher sulfur coal currently accounts for a significant portion of our sales, the extent to which electric power generators switch to alternative fuel could materially affect us. Recent EPA rulemaking proceedings requiring additional reductions in permissible emission levels of impurities by coal-fired plants will likely make it more costly to operate coal-fired electric power plants and may make coal a less attractive fuel alternative for electric power generation in the future. Examples are (i) adoption of the Cross-State Air Pollution Rule (CASPR) in 2011 (to be effective January 1, 2012, but currently subject to a stay ordering the agency to continue to enforce the Clean Air Interstate Rule promulgated in 2005 until a viable replacement to the cross-state regulation could be issued, with an appeal of CASPR currently pending before the U.S. Supreme Court); and (ii) adoption in 2012 of the Utility Maximum Control Technology (UMACT) rule in 2012, which included more stringent new source performance standards (NSPS) for particulate matter (PM), SO_2 and $NO_{X,}$ and the Mercury and Air Toxics Standards (MATS) rule which set new mercury and air toxic standards (both of which were reconsidered and reissued with slightly less stringent limits in 2013).

Another source of uncertainty is the consideration of regulation of coal ash disposal by the EPA. In May 2010, the EPA proposed new approaches for the regulation of Coal Combustion Residuals from electric generating facilities.

The EPA is re-evaluating its August 1993 and May 2000 Bevill determinations that currently provide exemptions from the definition of hazardous wastes for certain materials. In October 2013, the U.S. District Court for the District of Columbia ordered the EPA to publish proposed coal ash facility regulations under the non-hazardous provisions of the Resource Conservation and Recovery Act. The EPA proposed regulations are not yet published.

Apart from actual and potential regulation of emissions and solid wastes from coal-fired plants, state and federal mandates for increased use of electricity from renewable energy sources could have an impact on the market for our coal. Several states have enacted legislative mandates requiring electricity suppliers to use renewable energy sources to generate a certain percentage of power. There have been numerous proposals to establish a similar uniform, national standard although none of these proposals have been enacted to date. Possible advances in technologies and incentives, such as tax credits, to enhance the economics of renewable energy sources could make these sources more competitive with coal. Any reductions in the amount of coal consumed by domestic electric power generators as a result of current or new standards for the emission of impurities or incentives to switch to alternative fuels or renewable energy sources could reduce the demand for our coal, thereby reducing our revenues and adversely affecting our business and results of operations.

Regulation of greenhouse gas emissions as well as uncertainty concerning such regulation could adversely impact the market for natural gas and coal and the regulation of greenhouse gas emissions may increase our operating costs and reduce the value of our natural gas and coal assets.

While climate change legislation in the U.S. is unlikely in the next several years, the issue of global climate change continues to attract considerable public and scientific attention with widespread concern about the impacts of human activity, especially the emissions of greenhouse gases (GHGs), such as carbon dioxide and methane. Combustion of fossil fuels, such as the natural gas and coal we produce, results in the creation of carbon dioxide emissions into the atmosphere by natural gas and coal end-users, such as coal-fired electric power generation plants. Numerous proposals have been made and are likely to continue to be made at the international, national, regional and state levels of government that are intended to limit emissions of GHGs. Several states have already adopted measures requiring reduction of GHGs within state boundaries. Internationally, the Kyoto Protocol, which set binding emission targets for developed countries (but has not been ratified by the United States, and Canada officially withdrew from its Kyoto commitment in 2012) was nominally extended past its expiration date of December 2012 with a requirement for a new legal construct to be put into place by 2015. The EPA has elected to regulate GHGs under the Clean Air Act. On January 8, 2014, EPA re-proposed NSPS for CO2 for new fossil fuel fired power plants and rescinded the rules that were proposed on April 12, 2012. These proposed rules will also require CCS for new coal fired power plants.

Apart from governmental regulation, on February 4, 2008, three of Wall Street's largest investment banks announced that they had adopted climate change guidelines for lenders. The guidelines require the evaluation of carbon risks in the financing of electric power generation plants which may make it more difficult for utilities to obtain financing for coal-fired plants.

Adoption of comprehensive legislation or regulation focusing on GHGs emission reductions for the United States or other countries where we sell coal, or the inability of utilities to obtain financing in connection with coal-fired plants, it may make it more costly to operate fossil fuel fired (especially coal-fired) electric power generation plants and make fossil fuels less attractive for electric utility power plants in the future. Depending on the nature of the regulation or legislation, natural gas-fueled power generation could become more economically attractive than coal-fueled power generation, substantially increasing the demand for natural gas. Apart from actual regulation, uncertainty over the extent of regulation of GHG emissions may inhibit utilities from investing in the building of new coal-fired plants to replace older plants or investing in the upgrading of existing coal-fired plants. Any reduction in the amount of coal or possibly natural gas consumed by domestic electric power generators as a result of actual or potential regulation of greenhouse gas emissions could decrease demand for our fossil fuels, thereby reducing our revenues and materially and adversely affecting our business and results of operations. We or our customers may also have to invest in carbon dioxide capture and storage technologies in order to burn coal or natural gas and comply with future GHG emission standards.

In addition, coalbed methane must be expelled from our underground coal mines for mining safety reasons. Coalbed methane has a greater GHG effect than carbon dioxide. Our gas operations capture coalbed methane from our underground coal mines, although some coalbed methane is vented into the atmosphere when the coal is mined. If regulation of GHG emissions does not exempt the release of coalbed methane, we may have to further reduce our methane emissions, pay higher taxes, incur costs to purchase credits that permit us to continue operations as they now exist at our underground coal mines or perhaps curtail coal production.

Foreign currency fluctuations could adversely affect the competitiveness of our coal abroad.

We compete in international markets against coal produced in other countries. Coal is sold internationally in U.S. dollars. As a result, mining costs in competing producing countries may be reduced in U.S. dollar terms based on currency exchange rates, providing an advantage to foreign coal producers. Currency fluctuations among countries purchasing and selling coal could adversely affect the competitiveness of our coal in international markets.

Our natural gas and coal mining operations are subject to operating risks, which could increase our operating expenses and decrease our production levels which could adversely affect our results of operations. Our natural gas and coal operations are also subject to hazards and any losses or liabilities we suffer from hazards which occur in our operations may not be fully covered by our insurance policies.

Our exploration for and production of natural gas involves numerous operating risks. The cost of drilling, completing and operating our shale gas wells, shallow oil and gas wells and coalbed methane (CBM) wells is often uncertain, and a number of factors can delay or prevent drilling operations, decrease production and/or increase the cost of our gas operations at particular sites for varying lengths of time thereby adversely affecting our operating results. The operating risks that may have a significant impact on our gas operations include:

- unexpected drilling conditions;
- title problems;
- pressure or irregularities in geologic formations;
- equipment failures or repairs;
- fires, explosions or other accidents;
- adverse weather conditions;
- reductions in natural gas prices;
- security breaches or terroristic acts;
- pipeline ruptures;
- lack of adequate capacity for treatment or disposal of waste water generated in drilling, completion and production operations;
- environmental contamination from surface spillage of fluids used in well drilling, completion or operation including fracturing fluids used in hydraulic fracturing of wells, or other contamination of groundwater or the environment resulting from our use of such fluids; and
- unavailability or high cost of drilling rigs, other field services and equipment.

Our coal mining operations are predominantly underground mines. These mines are subject to a number of operating risks that could disrupt operations, decrease production and increase the cost of mining at particular mines for varying lengths of time thereby adversely affecting our operating results. In addition, if coal production declines, we may not be able to produce sufficient amounts of coal to deliver under our long-term coal contracts. CONSOL Energy's inability to satisfy contractual obligations could result in our customers initiating claims against us. The operating risks that may have a significant impact on our coal operations include:

- variations in thickness of the layer, or seam, of coal;
- amounts of rock and other natural materials intruding into the coal seam and other geological conditions that could affect the stability of the roof and the side walls of the mine;
- equipment failures or repairs;
- fires, explosions or other accidents;
- weather conditions; and
- security breaches or terroristic acts.

Although we maintain insurance for a number of hazards, we may not be insured or fully insured against the losses or liabilities that could arise from a significant accident in our gas or coal operations.
A decrease in the availability or increase in the costs of commodities or capital equipment used in mining operations could decrease our coal production, impact our cost of coal production and decrease our anticipated profitability.

Coal mining consumes large quantities of commodities including steel, copper, rubber products and liquid fuels and requires the use of capital equipment. Some commodities, such as steel, are needed to comply with roof control plans required by regulation. The prices we pay for commodities and capital equipment are strongly impacted by the global market. A rapid or significant increase in the costs of commodities or capital equipment we use in our operations could impact our mining operations costs because we may have a limited ability to negotiate lower prices, and, in some cases, may not have a ready substitute.

We rely upon third party contractors to provide various field services to our gas and coal operations. A decrease in the availability of or an increase in the prices charged by third party contractors or failure of third party contractors to provide quality services to us in a timely manner could decrease our production, increase our costs of production, and decrease our anticipated profitability.

We rely upon third party contractors to provide key services to our gas operations. We contract with third parties for well services, related equipment, and qualified experienced field personnel to drill wells and conduct field operations. The demand for these field services in the natural gas and oil industry can fluctuate significantly. Higher oil and natural gas prices generally stimulate increased demand causing periodic shortages. These shortages may lead to escalating prices for drilling equipment, crews and associated supplies, equipment and services. Shortages may lead to poor service and inefficient drilling operations and increase the possibility of accidents due to the hiring of inexperienced personnel and overuse of equipment by contractors. In addition, the costs and delivery times of equipment and supplies are substantially greater in periods of peak demand. Accordingly, we cannot assure that we will be able to obtain necessary drilling equipment and supplies in a timely manner or on satisfactory terms, and we may experience shortages of, or increases in the costs of, drilling equipment, crews and associated supplies, equipment and field services in the future. We utilize third-party contractors to provide land acquisition and related services to support our land operational needs for both gas and coal segments. We also use third party contractors to provide construction and specialized services to our mining operations. A decrease in the availability of field services or equipment and supplies, an increase in the prices charged for field services, equipment and supplies, or the failure of third party contractors to provide quality field services to us, could decrease our gas and coal production, increase our costs of gas and coal production, and decrease our anticipated profitability.

We attempt to mitigate the risks involved with increased industrial activity by entering into “take or pay” contracts with well service providers which commit them to provide field services to us at specified levels and commit us to pay for field services at specified levels even if we do not use those services. However, these contracts expose us to economic risk. For example, if the price of natural gas declines and it is not economical to drill and produce additional natural gas, we may have to pay for field services that we did not use. This would decrease our cash flow and raise our costs of production.

For drilling and mining operations, CONSOL Energy must obtain, maintain, and renew governmental permits and approvals which if we cannot obtain in a timely manner would reduce our production, cash flow and results of operations.

State and local authorities regulate various aspects of gas drilling and production activities, including the drilling of wells (through permit and bonding requirements), the spacing of wells, the unitization or pooling of gas properties, environmental matters, safety standards, market sharing and well site restoration. Delays or denials of gas permits could reduce our production, cash flows and results of operations.

Most coal producers in the eastern U.S. are being impacted by government regulations and enforcement to a much greater extent than a few years ago, particularly in light of the renewed focus by environmental agencies and the government generally on the mining industry, including more stringent enforcement and interpretation of the laws that regulate mining. The pace with which the government issues permits needed for new operations and for on-going operations to continue mining has negatively impacted expected production, especially in Central Appalachia. Environmental groups in Southern West Virginia and Kentucky have challenged state and U.S. Army Corps of Engineers permits for mountaintop and other types of surface mining operations on various grounds. The most recent challenges have focused on the adequacy of the U.S Army Corps of Engineers analysis of impacts to streams and the adequacy of mitigation plans to compensate for stream impacts resulting from valley fill permits required for mountaintop mining. These challenges have also enhanced the EPA's oversight and involvement in the review of permits by state regulatory authorities. In 2007, the U.S. District Court for the Southern District of West Virginia found other operators' permits for mining in these areas to be deficient. In February 2009, the U.S. Court of Appeals for the Fourth Circuit reversed that decision, finding that the permits were adequate. Nevertheless, the EPA's objections and an enhanced review process that was being implemented under a federal multi-agency memorandum of understanding effectively held up the issuance of permits for all types of mining operations that require Clean Water Act Section 402 discharge permits and Section 404 dredge and fill permits, including surface facilities for underground mines. The EPA's enhanced review process was invalidated in October 2011, in part because the EPA failed to follow public notice and rulemaking requirements, and on July 31, 2012, the federal District Court for the District of Columbia struck down the EPA's “guidance memorandum” for coal-related water permitting actions in which the EPA recommended permits include limits on specific conductivity which currently neither the EPA nor the states have a standard. However, normal permitting has not yet resumed. Also, the EPA may elect to seek to adopt regulations to codify its enhanced review process. CONSOL Energy's surface and underground operations have been impacted to a limited extent to date, but a permit for a new mine was impacted which resulted in the issuance of a Worker Adjustment and Retraining Notification (WARN) which affected some 145 employees on October 30, 2012. CONSOL Energy was able, in this instance, to redeploy these employees to work at another adjacent coal mine property for which a permit was already issued. However, the permit for the new mine still has not been issued and there is no assurance that CONSOL Energy would be able to re-deploy its employees under future similar circumstances. In addition, the length of time needed to bring a new mine into production has increased by several years because of the increased time required to obtain necessary permits. These delays or denials of mining permits could reduce our production, cash flow and results of operations.

Existing and future government laws, regulations and other legal requirements relating to protection of the environment, and others that govern our business may increase our costs of doing business for coal and may restrict our coal operations.

We are subject to laws, regulations and other legal requirements enacted or adopted by federal, state and local authorities, as well as foreign authorities relating to protection of the environment. These include those legal requirements that govern discharges of substances into the air and water, the management and disposal of hazardous substances and wastes, the cleanup of contaminated sites, groundwater quality and availability, threatened and endangered plant and wildlife protection, reclamation and restoration of mining or drilling properties after mining or drilling is completed, the installation of various safety equipment in our mines, remediation of impacts of surface subsidence from underground mining, and work practices related to employee health and safety. Complying with these requirements, including the terms of our permits, has had, and will continue to have, a significant effect on our costs of operations and competitive position.

In addition, there is the possibility that we could incur substantial costs as a result of violations under environmental laws. Any additional laws, regulations and other legal requirements enacted or adopted by federal, state and local authorities, as well as foreign authorities or new interpretations of existing legal requirements by regulatory bodies relating to the protection of the environment could further affect our costs of operations and competitive position. The Clean Water Act is being used by opponents of mountain top removal mining as a means to challenge permits and bring citizen suits to make coal mining more expensive. In addition, CONSOL Energy may incur costs associated with the investigation and remediation of environmental contamination under the federal Comprehensive Environmental Response, Compensation, and Liability Act (Superfund) and similar state statutes and has been named as a potentially responsible party at Superfund sites in the past.

Existing and future government laws, regulations and other legal requirements relating to protection of the environment, and others that govern our business may increase our costs of doing business for natural gas, and may restrict our gas operations.

Regulations applicable to the gas industry are under constant review for amendment or expansion at the federal and state level. Any future changes may affect, among other things, the pricing or marketing of gas production. For example, hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations such as Marcellus Shale. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and gas commissions. Hydraulic fracturing is currently exempt from regulation under the federal Safe Drinking Water Act, except for hydraulic fracturing using diesel fuel. The disposal of produced water, drilling fluids and other wastes in underground injection disposal wells is regulated by the EPA under the federal Safe Drinking Water Act or by the states under counterpart state laws and regulations. The imposition of new environmental initiatives and regulations could include restrictions on our ability to conduct hydraulic fracturing operations or to dispose of waste resulting from such operations. The EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities with a final report to be issued in 2014. Other federal agencies are also examining hydraulic fracturing, including the U.S. Department of Energy (DOE), the U.S. Government Accountability Office and the Department of the Interior. Also, some states have adopted, and other states are considering adopting, regulations that could restrict or impose additional requirements relating to hydraulic fracturing in certain circumstances. If hydraulic fracturing is regulated at the federal, state or local level, our fracturing activities could become subject to additional permit requirements or operational restrictions and also to associated permitting delays and potential increases in costs.

Additionally, some states have begun to adopt more stringent regulation and oversight of natural gas gathering lines than is currently required by federal standards. Pennsylvania, under Act 127, authorized the Public Utility Commission (PUC) oversight of Class I gathering lines, as well as requiring standards and fees associated with Class II and Class III pipelines. The state of Ohio also moved to regulate natural gas gathering lines in a similar manner pursuant to Ohio Senate Bill 315 (SB315). SB315 expanded the PUC's authority over rural natural gas gathering lines. These changes in interpretation and regulation affect CONSOL Energy's midstream activities, requiring changes in reporting as well as increased costs.

Further, some state and local governments in the Marcellus Shale region in Pennsylvania and New York have considered or imposed a temporary moratorium on drilling operations using hydraulic fracturing until further study of the potential for environmental and human health impacts by the EPA or the relevant agencies are completed. Also, a few municipalities in Colorado have adopted ordinances to ban hydraulic fracturing. No assurance can be given as to whether or not similar measures might be considered or implemented in jurisdictions in which our gas properties are located. If new laws or regulations that significantly restrict or otherwise impact hydraulic fracturing are passed by Congress or adopted in states in which we operate, such legal requirements could make it more difficult or costly for us to perform hydraulic fracturing activities and thereby could affect the determination of whether a well is commercially viable. New laws or regulations could also cause delays or interruptions or terminations of operations, the extent of which cannot be predicted, and could reduce the amount of oil and natural gas that we ultimately are able to produce in commercially paying quantities from our gas properties, all of which could have a material adverse effect on our results of operations and financial condition.

Our shale gas drilling and production operations require both adequate sources of water to use in the fracturing process as well as the ability to dispose of water and other wastes after hydraulic fracturing. Our CBM gas drilling and production operations also require the removal and disposal of water from the coal seams from which we produce gas. If we cannot find adequate sources of water for our use or are unable to dispose of the water we use or remove it from the strata at a reasonable cost and within applicable environmental rules, our ability to produce gas economically and in commercial quantities could be impaired.

As part of our drilling and production in shale formations, we use hydraulic fracturing processes. Thus, we need access to adequate sources of water to use in our shale operations. Further, we must remove and dispose of the portion of the water that we use to fracture our shale gas wells that flows back to the well-bore as well as drilling fluids and other wastes associated with the exploration, development or production of natural gas. In addition, in our CBM drilling and production, coal seams frequently contain water that must be removed and disposed of in order for the gas to detach from the coal and flow to the well bore. Our inability to locate sufficient amounts of water with respect to our shale operations, or the inability to dispose of or recycle water and other wastes used in our shale and our CBM operations, could adversely impact our operations. For example, in Ohio, underground injection of gas well production fluids was temporarily suspended for underground injection disposal wells near Youngstown while regulatory authorities investigated whether injection of wastewater into the wells was causing low category earthquakes in the area.

Our mines are subject to stringent federal and state safety regulations that increase our cost of doing business at active operations and may place restrictions on our methods of operation. In addition, government inspectors under certain circumstances, have the ability to order our operations to be shutdown based on safety considerations. A mine could be shutdown for an extended period of time if a disaster were to occur at it.

Stringent health and safety standards were imposed by federal legislation when the Federal Coal Mine Health and Safety Act of 1969 was adopted. The Federal Coal Mine Safety and Health Act of 1977 expanded the enforcement of safety and health standards of the Coal Mine Health and Safety Act of 1969 and imposed safety and health standards on all (non-coal as well as coal) mining operations. Regulations are comprehensive and affect numerous aspects of mining operations, including training of mine personnel, mining procedures, the equipment used in mine emergency procedures, mine plans and other matters. The additional requirements of the Mine Improvement and New Emergency Response Act of 2006 (the Miner Act) and implementing federal regulations include, among other things, expanded emergency response plans, providing additional quantities of breathable air for emergencies, installation of refuge chambers in underground coal mines, installation of two-way communications and tracking systems for underground coal mines, new standards for sealing mined out areas of underground coal mines, more available mine rescue teams and enhanced training for emergencies. Most states in which CONSOL Energy operates have programs for mine safety and health regulation and enforcement. We believe that the combination of federal and state safety and health regulations in the coal mining industry is, perhaps, the most comprehensive system for protection of employee safety and health affecting any industry. Most aspects of mine operations, particularly underground mine operations, are subject to extensive regulation. The various requirements mandated by law or regulation can place restrictions on our methods of operations, creating a significant effect on operating costs and productivity. In addition, government inspectors under certain circumstances, have the ability to order our operation to be shutdown based on safety considerations. If a disaster were to occur at one of our mines, it could be shutdown for an extended period of time and our reputation with our customers could be materially damaged.

Our operations may impact the environment or cause exposure to hazardous substances, and our properties may have environmental contamination, which could result in liabilities to us.

Our operations currently use hazardous materials and generate limited quantities of hazardous wastes from time to time. Drainage flowing from or caused by mining activities can be acidic with elevated levels of dissolved metals, a condition referred to as “acid mine drainage.” We could become subject to claims for toxic torts, natural resource damages and other damages as well as for the investigation and clean up of soil, surface water, groundwater, and other media. Such claims may arise, for example, out of conditions at sites that we currently own or operate, as well as at sites that we previously owned or operated, or may acquire. Our liability for such claims may be joint and several, so that we may be held responsible for more than our share of the contamination or other damages, or for the entire share.

We maintain extensive coal refuse areas and slurry impoundments at a number of our mining complexes. Such areas and impoundments are subject to extensive regulation. Structural failure of a slurry impoundment or coal refuse area could result in extensive damage to the environment and natural resources, such as bodies of water that the coal slurry reaches, as well as liability for related personal injuries and property damages, and injuries to wildlife. Some of our impoundments overlie mined out areas, which can pose a heightened risk of failure and of damages arising out of failure. If one of our impoundments were to fail, we could be subject to claims for the resulting environmental contamination and associated liability, as well as for fines and penalties. Our coal refuse areas and slurry impoundments are designed, constructed, and inspected by our company and by regulatory authorities according to stringent environmental and safety standards.

In West Virginia there are areas where drainage from coal mining operations contains concentrations of selenium that without treatment would result in violations of state water quality standards that are set to protect fish and other aquatic life. CONSOL Energy has several operations with selenium discharges. CONSOL Energy and other coal companies are working to expeditiously develop cost effective means to remove selenium from mine water. If such technology or processes are not developed promptly, the only available effective treatment technologies are expensive to construct and operate which will increase coal production costs.

These and other similar unforeseen impacts that our operations may have on the environment, as well as exposures to hazardous substances or wastes associated with our operations, could result in costs and liabilities that could adversely affect us. An example of this is Naturally Occurring Radioactive Material (NORM) or Technologically-Enhanced, Naturally Occurring Radioactive Material (TENORM). NORM or TENORM is produced when activities such as deep drilling concentrate or expose radioactive materials that occur naturally in ores, soils, water, or other natural materials. State and federal agencies are examining the possibility for worker exposure or associated environmental hazards due to processing and disposal of wastes containing NORM or TENORM. CONSOL Energy's operations could be affected if there is a hazard associated with NORM/TENORM or if it were to be regulated in such a way as to require expensive treatment and disposal options.

CONSOL Energy has reclamation, mine closing and gas well plugging obligations. If the assumptions underlying our accruals are inaccurate, we could be required to expend greater amounts than anticipated.

The Surface Mining Control and Reclamation Act establishes operational, reclamation and closure standards for all aspects of surface mining as well as most aspects of deep mining. Also, state laws require us to plug gas wells and reclaim well sites after the useful life of our gas wells has ended. CONSOL Energy accrues for the costs of current mine disturbance, gas well plugging and of final mine closure, including the cost of treating mine water discharge where necessary. Estimates of our total reclamation, mine-closing liabilities and gas well plugging, which are based upon permit requirements and our experience, were approximately $601 million at December 31, 2013. The amounts recorded are dependent upon a number of variables, including the estimated future closure costs, estimated proven reserves, assumptions involving profit margins, inflation rates, and the assumed credit-adjusted risk-free interest rates. Furthermore, these obligations are unfunded. If these accruals are insufficient or our liability in a particular year is greater than currently anticipated, our future operating results could be adversely affected.

Most states where we operate require us to post bonds for the full cost of coal mine reclamation (full cost bonding). West Virginia is not a full cost bonding state. West Virginia has an alternative bond system (ABS) for coal mine reclamation which consists of (i) individual site bonds posted by the permittee that are less than the full estimated reclamation cost plus (ii) a bond pool (Special Reclamation Fund) funded by a per ton fee on coal mined in the State which is used to supplement the site specific bonds if needed in the event of bond forfeiture. The Special Reclamation Fund was underfunded, resulting in a citizen suit before the U.S. District Court in West Virginia. In an effort to settle the issue in 2012, the WV legislature authorized an increase in the per ton fee levied on coal production to make up the shortfall. There remains the possibility that WV may move to full cost bonding in the future which could cause individual mining companies and/or surety companies to exceed bonding capacity and would result in the need to post cash bonds or letters of credit which would reduce operating capital. Pennsylvania is expanding its full cost bonding program to cover all coal mine bonding, further increasing the amount of surety bonds CONSOL Energy must seek in order to permit its mining activities.

CONSOL Energy faces uncertainties in estimating our economically recoverable gas and coal reserves, and inaccuracies in our estimates could result in lower than expected revenues, higher than expected costs and decreased profitability.

Natural gas reserves require subjective estimates of underground accumulations of natural gas and assumptions concerning natural gas prices, production levels, and operating and development costs. As a result, estimated quantities of proved gas reserves and projections of future production rates and the timing of development expenditures may be incorrect. Over time, material changes to reserve estimates may be made, taking into account the results of actual drilling, testing and production. Also, we make certain assumptions regarding natural gas prices, production levels, and operating and development costs that may prove incorrect. Any significant variance from these assumptions to actual figures could greatly affect our estimates of our gas reserves, the economically recoverable quantities of natural gas attributable to any particular group of properties, the classifications of gas reserves based on risk of recovery, and estimates of the future net cash flows. Numerous changes over time to the assumptions on which our reserve estimates are based, as described above, often result in the actual quantities of gas we ultimately recover being different from reserve estimates. The present value of future net cash flows from our proved reserves is not necessarily the same as the current market value of our estimated natural gas reserves. We base the estimated discounted future net cash flows from our proved gas reserves on historical average prices and costs. However, actual future net cash flows from our gas and oil properties also will be affected by factors such as:

- geological conditions;
- changes in governmental regulations and taxation;
- the amount and timing of actual production;
- assumptions governing future prices;
- future operating costs; and
- capital costs of drilling, completion and gathering assets.

The timing of both our production and our incurrence of expenses in connection with the development and production of natural gas properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net cash flows may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the natural gas and oil industry in general. If natural gas prices decline by $0.10 per Mcf, then the pre-tax present value using a 10% discount rate of our proved gas reserves as of December 31, 2013 would decrease from $2.8 billion to $2.6 billion.

Similarly, there are uncertainties inherent in estimating quantities and values of economically recoverable coal reserves, including many factors beyond our control. As a result, estimates of economically recoverable coal reserves are by their nature uncertain. Information about our reserves consists of estimates based on engineering, economic and geological data assembled and analyzed by our staff. Some of the factors and assumptions which impact economically recoverable coal reserve estimates include:

- geological conditions;
- historical production from the area compared with production from other producing areas;
- the assumed effects of regulations and taxes by governmental agencies;
- assumptions governing future prices; and
- future operating costs, including the cost of materials.

In addition, we hold substantial coal reserves in areas containing Marcellus Shale and other shales. These areas are currently the subject of substantial exploration for oil and gas, particularly by horizontal drilling. If a well is in the path of our mining for coal, we may not be able to mine through the well unless we purchase it. Although in the past we have purchased vertical wells, the cost of purchasing a producing horizontal well could be substantially greater. Horizontal wells with multiple laterals extending from the well pad may access larger oil and gas reserves than a vertical well which could result in higher costs. In future years, the cost associated with purchasing oil and gas wells which are in the path of our coal mining may make mining through those wells uneconomical thereby effectively causing a loss of significant portions of our coal reserves.

Each of the factors which impacts reserve estimation may in fact vary considerably from the assumptions used in estimating the reserves. For these reasons, estimates of gas and coal reserves may vary substantially. Actual production, revenues and expenditures with respect to our coal and gas reserves will likely vary from estimates, and these variances may be material. As a result, our estimates may not accurately reflect our actual coal and gas reserves.

Defects may exist in our chain of title for our gas estate and we have not done a thorough chain of title examination of our gas estate. We may incur additional costs and delays to produce gas and coal because we have to acquire additional property rights to perfect our title to gas or coal rights. If we fail to acquire additional property rights to perfect our title to gas or coal rights, we may have to reduce our estimated reserves.

Substantial amounts of acreage in which we believe we control gas rights are in areas where we have not yet done a thorough chain of title examination of the gas estate. A number of our gas properties were acquired primarily for the coal rights with the focus on the coal estate title, and, in many cases were acquired years ago. In addition, we have acquired gas rights in substantial acreage from third parties who had not performed thorough chain of title work on their gas properties. Our practice, and we believe industry practice, is not to perform a thorough title examination on gas properties until shortly before the commencement of drilling activities at which time we seek to acquire any additional rights needed to perfect our ownership of the gas estate for development and production purposes. When we perform a thorough chain of title examination, we may discover material defects in our title which would require us to acquire additional property rights. We may incur substantial costs to acquire these additional property rights. In addition, the acquisition of the necessary rights may not be feasible in some cases. Our discovering title defects which we are unable to cure may adversely impact our ability to develop those properties and we may have to reduce our estimated gas reserves including our proved undeveloped reserves.

Some states (West Virginia and Virginia) permit us to produce coalbed methane gas without perfected ownership under an administrative process known as “pooling,” which require us to give notice to all potential claimants and pay royalties into escrow until the undetermined rights are resolved. As a result, we may have to pay royalties to produce coalbed methane gas on acreage that we control and these costs may be material. Further, the pooling process is time-consuming and may delay our drilling program in the affected areas.

While chain of title for our coal estate generally has been established, there may be defects in it that we do not realize until we have committed to developing those properties or coal reserves. As such, the title to the coal estate that we intend to mine may contain defects. In order to conduct our mining operations on properties where these defects exist, we may incur unanticipated costs perfecting title. If we cannot cure these defects, we may have to reduce our coal reserves.

Our subsidiaries, primarily Fairmont Supply Company, are co-defendants in various asbestos litigation cases which could result in making payments in the future that are material.

One of our subsidiaries, Fairmont Supply Company (Fairmont), which distributes industrial supplies, currently is named as a defendant in approximately 6,900 asbestos-related claims in state courts in Pennsylvania, Ohio, West Virginia, Maryland, Texas and Illinois. Because a very small percentage of products manufactured by third parties and supplied by Fairmont in the past may have contained asbestos and many of the pending claims are part of mass complaints filed by hundreds of plaintiffs against a hundred or more defendants, it has been difficult for Fairmont to determine how many of the cases actually involve valid claims or plaintiffs who were actually exposed to asbestos-containing products supplied by Fairmont. In addition, while Fairmont may be entitled to indemnity or contribution in certain jurisdictions from manufacturers of identified products, the availability of such indemnity or contribution is unclear at this time, and in recent years, some of the manufacturers named as defendants in these actions have sought protection from these claims under bankruptcy laws. Fairmont has no insurance coverage with respect to these asbestos cases. Past payments by Fairmont with respect to asbestos cases have not been material, however, it is reasonably possible that payments in the future with respect to pending or future asbestos cases may be material to the financial position, results of operations or cash flows of CONSOL Energy.
CONSOL Energy and its subsidiaries are subject to various legal proceedings, which may have an adverse effect on our business.

We are party to a number of legal proceedings in the normal course of business activities. Defending these actions, especially purported class actions, can be costly, and can distract management. For example, we are a defendant in three pending purported class action lawsuits dealing with claimants’ entitlement to, and accounting for, gas royalties. There is the potential that the costs of defending litigation in an individual matter or the aggregation of many matters could have an adverse effect on our cash flows, results of operations or financial position. See Note 24-Commitments and Contingent Liabilities in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for further discussion of pending legal proceedings.

CONSOL Energy has obligations for long-term employee benefits for which we accrue based upon assumptions which, if inaccurate, could result in CONSOL Energy being required to expense greater amounts than anticipated.

CONSOL Energy provides various long-term employee benefits to inactive and retired employees. We accrue amounts for these obligations. At December 31, 2013, the current and non-current portions of these obligations included:

- postretirement medical and life insurance ($1.0 billion);
- coal workers' black lung benefits ($121.2 million);
- salaried retirement benefits ($43.8 million); and
- workers' compensation ($85.1 million).

However, if our assumptions are inaccurate, we could be required to expend greater amounts than anticipated. Salary retirement benefits are funded in accordance with Employer Retirement Income Security Act of 1974 (ERISA) regulations. The other obligations are unfunded. In addition, the federal government and several states in which we operate consider changes in workers' compensation and black lung laws from time to time. Such changes, if enacted, could increase our benefit expense.

If lump sum payments made to retiring salaried employees pursuant to CONSOL Energy's defined benefit pension plan exceed the total of the service cost and the interest cost in a plan year, CONSOL Energy would need to make an adjustment to operating results equaling the unrecognized actuarial gain or loss resulting from each individual who received a lump sum payment in that year, which may result in an adjustment that could reduce operating results.

CONSOL Energy's defined benefit pension plan for salaried employees allows such employees to receive a lump-sum distribution for benefits earned up through December 31, 2005 in lieu of annual payments when they retire from CONSOL

Energy. Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans for Terminations Benefits requires that if the lump-sum distributions made for a plan year exceed the total of the service cost and interest cost for the plan year, CONSOL Energy would need to recognize for that year's results of operations an adjustment equaling the unrecognized actuarial gain or loss resulting from each individual who received a lump sum in that year. If the settlement is triggered in future periods, it may be material to operating results.

Acquisitions that we have completed, acquisitions that we may undertake in the future, as well as expanding existing company mines, involve a number of risks, any of which could cause us not to realize the anticipated benefits and to the extent we plan to engage in joint ventures and divestitures, we do not control the timing of these and they may not provide anticipated benefits.

We have completed several acquisitions and investments in the past. We also continually seek to grow our business by adding and developing gas and coal reserves through acquisitions and by expanding the production at existing mines and existing gas operations. If we are unable to successfully integrate the companies, businesses or properties we acquire, we may fail to realize the expected benefits of the acquisition and our profitability may decline and we could experience a material adverse effect on our business, financial condition, or results of operations. Acquisitions, mine expansion and gas operation expansion involve various inherent risks, including:

- uncertainties in assessing the value, strengths, and potential profitability of, and identifying the extent of all weaknesses, risks, contingent and other liabilities (including environmental liabilities) of expansion and acquisition opportunities;
- the potential loss of key customers, management and employees of an acquired business;
- the ability to achieve identified operating and financial synergies anticipated to result from an expansion or an acquisition opportunity;
- the potential revision of assumptions regarding gas reserves as we acquire more knowledge by operating an acquired gas business;
- problems that could arise from the integration of the acquired business;
- unanticipated changes in business, industry or general economic conditions that affect the assumptions underlying our rationale for pursuing the expansion or the acquisition opportunity; and
- we may have to assume cleanup or reclamation obligations or other unanticipated liabilities in connection with these acquisitions.

From time to time part of our business and financing plans include entering into joint venture arrangements and the divestiture of certain assets. However, we do not control the timing of divestitures or joint venture arrangements and delays in entering into divestitures or joint venture arrangements may reduce the benefits from them. In addition, the terms of divestitures and joint venture arrangements may make a substantial portion of the benefits we anticipate receiving from them to be subject to future matters that we do not control.

We have entered into two significant gas joint ventures. These joint ventures restrict our operational and corporate flexibility; actions taken by our joint venture partners may materially impact our financial position and results of operation; and we may not realize the benefits we expect to realize from these joint ventures.

In the second half of 2011 CONSOL Energy, through its principal gas operations subsidiary, CNX Gas Company LLC (CNX Gas Company), entered into joint venture arrangements with Noble Energy, Inc. (Noble Energy) and Hess Ohio Developments, LLC (Hess) regarding our shale gas assets. We sold a 50% undivided interest in our Marcellus shale oil and gas assets to Noble Energy and a 50% undivided interest in our Utica shale acres in Ohio to Hess. The following aspects of these joint ventures could materially impact CONSOL Energy:

-

The development of these properties is subject to the terms of our joint development agreements with these parties and we no longer have the flexibility to control the development of these properties. For example, the joint development agreements for each of these joint ventures sets forth required capital expenditure programs that each party must participate in unless the parties mutually agree to change such programs or, in certain limited circumstances in the case of the Noble Energy joint development agreement, a party elects to exercise a non-consent right with respect to an entire year. If we do not timely meet our financial commitments under the respective joint venture agreements, our rights to participate in such joint ventures will be adversely affected and the other parties to the joint ventures may have a right to acquire a share of our interest in such joint ventures proportionate to, and in satisfaction of, our unmet financial obligations. In addition, each joint venture party has the right to elect to participate in all acreage and other acquisitions in certain defined areas of mutual interest.

- Each joint development agreement assigns to each party designated areas over which that party will manage and control operations. We could incur liability as a result of action taken by one of our joint venture partners.
- Approximately $1.9 billion of consideration that we expect to receive from Noble Energy depends upon Noble Energy paying a portion of our share of drilling and development costs for new wells, which we call “carried costs.” We entered into a similar transaction with Hess Ohio Developments, LLC (Hess) in which approximately $335 million of consideration that we expect to receive from Hess is dependent upon Hess paying carried costs. Thus, the benefits we anticipate receiving in the joint ventures depend in part upon the rate at which new wells are drilled and developed in each joint venture, which could fluctuate significantly from period to period. Moreover, the performance of these third party obligations is outside our control. The inability or failure of a joint venturer to pay its portion of development costs, including our carried costs during the carry period, could increase our costs of operations or result in reduced drilling and production of oil and gas or loss of rights to develop the oil and gas properties held by that joint venture.
- Noble Energy's obligation to pay carried costs is suspended if average Henry Hub natural gas prices fall and remain below $4.00 per million British thermal units or “MMbtu” in any three consecutive month period and will remain suspended until average natural gas prices are above $4.00/MMbtu for three consecutive months. As a result of this provision, Noble Energy's obligation to pay carried costs was suspended beginning on December 1, 2011. We cannot predict when this suspension will be lifted and Noble Energy's obligation to pay the carried costs will resume. This suspension has the effect of requiring us to incur our entire 50 percent share of the drilling and completion costs for new wells during the suspension period and delaying receipt of a portion of the value we expect to receive in the transaction.
- The Noble Energy joint development agreement prohibits prior to March 31, 2014, unless Noble Energy consents in its sole discretion, any transfer of our interests in the Noble Energy joint venture assets or our selling or otherwise transferring control of CNX Gas Company. The Hess joint development agreement prohibits prior to October 21, 2014, unless Hess consents in its sole discretion, any transfer of our interests in the Hess joint venture assets. These restrictions may preclude transactions which could be beneficial to our shareholders.
- Disputes between us and our joint venture partners may result in litigation or arbitration that would increase our expenses, delay or terminate projects and distract our officers and directors from focusing their time and effort on our business.

We may also enter into other joint venture arrangements in the future which could pose risks similar to risks described above.

The provisions of our debt agreements and the risks associated with our debt could adversely affect our business, financial condition and results of operations.

As of December 31, 2013, our total indebtedness was approximately $3.175 billion of which approximately $1.5 billion was under our 8.00% senior unsecured notes due April 2017, $1.25 billion was under our 8.25% senior unsecured notes due April 2020, $250 million was under our 6.375% senior notes due 2021, $103 million was under our Maryland Economic Development Corporation Port Facilities Refunding Revenue Bonds (MEDCO) 5.75% revenue bonds due September 2025, $56 million of capitalized leases due through 2021, and $16 million of miscellaneous debt. The degree to which we are leveraged could have important consequences, including, but not limited to:

- increasing our vulnerability to general adverse economic and industry conditions;
- limiting our ability to obtain additional financing to fund future working capital, capital expenditures, acquisitions, development of our gas and coal reserves or other general corporate requirements;
- limiting our flexibility in planning for, or reacting to, changes in our business and in the coal and gas industries; and
- placing us at a competitive disadvantage compared to less leveraged competitors.

Our senior secured credit facilities and the indentures governing our 8.00%, 8.25% and 6.375% senior unsecured notes limit the incurrence of additional indebtedness unless specified tests or exceptions are met. In addition, our senior secured credit agreements and the indentures governing our 8.00%, 8.25% and 6.375% senior unsecured notes subject us to financial and/or other restrictive covenants. Under our senior secured credit agreements, we must comply with certain financial covenants on a quarterly basis including a minimum interest coverage ratio, and a maximum senior secured leverage ratio, as defined. Our senior secured credit agreements and the indentures governing our 8.00%, 8.25% and 6.375% senior unsecured notes impose a number of restrictions upon us, such as restrictions on granting liens on our assets, making investments, paying dividends, selling assets and engaging in acquisitions. Failure by us to comply with these covenants could result in an event of default that, if not cured or waived, could have an adverse effect on us.

If our cash flows and capital resources are insufficient to fund our debt service obligations, we may be forced to sell assets, seek additional capital or seek to restructure or refinance our indebtedness. These alternative measures may not be successful and may not permit us to meet our scheduled debt service obligations. In the absence of such operating results and resources, we could face substantial liquidity problems and might be required to sell material assets or operations to attempt to meet our debt service and other obligations. Our senior secured credit agreement and the indentures governing our 8.00%, 8.25% and 6.375% senior unsecured notes restrict our ability to sell assets and use the proceeds from the sales. We may not be able to consummate those sales or to obtain the proceeds which we could realize from them and these proceeds may not be adequate to meet any debt service obligations then due.

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

Producing natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Because total estimated proved reserves include our proved undeveloped reserves at December 31, 2013, production is expected to decline even if those proved undeveloped reserves are developed and the wells produce as expected. The rate of decline will change if production from our existing wells declines in a different manner than we have estimated and can change under other circumstances. Thus, our future natural gas reserves and production and, therefore, our cash flow and income are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire additional reserves to replace our current and future production at acceptable costs

Our hedging activities may prevent us from benefiting from price increases and may expose us to other risks.

To manage our exposure to fluctuations in the price of natural gas, we enter into hedging arrangements with respect to a portion of our expected production. As of January 21, 2014, we had hedges on approximately 129.3 Bcf of our 2014 natural gas production, 78.6 Bcf of our 2015 natural gas production, and 71.3 Bcf of our 2016 natural gas production. To the extent that we engage in hedging activities, we may be prevented from realizing the benefits of price increases above the levels of the hedges. If we choose not to engage in, or reduce our use of hedging arrangements in the future, we may be more adversely affected by changes in natural gas prices than our competitors who engage in hedging arrangements to a greater extent than we do.

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;
- the counterparties to our contracts fail to perform the contracts; or
- the creditworthiness of our counterparties or their guarantors is substantially impaired.

If our gas hedges would no longer qualify for hedge accounting, we will be required to mark them to market and recognize the adjustments through current year earnings. This may result in more volatility in our income in future periods.

Changes in federal or state income tax laws, particularly in the area of percentage depletion and intangible drilling costs, could cause our financial position and profitability to deteriorate.

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

In February 2012, the state legislature of Pennsylvania passed a new natural gas impact fee in Pennsylvania, where a substantial portion of our acreage in the Marcellus Shale is located. The legislation imposes an annual fee on natural gas and oil operators for each well drilled for a period of fifteen years. The fee is on a sliding scale set by the Public Utility Commission and is based on two factors: changes in the Consumer Price Index and the average New York Mercantile Exchange's natural gas prices from the last day of each month. The estimated total fees per well based on today's current natural gas price is $310 thousand over the 15 year period. The passage of this legislation increases the financial burden on our operations in the Marcellus Shale.

Several portions of Act 13 were overturned by the Pennsylvania Supreme Court in December 2013, including the portion that addressed municipal uniformity, and the Company is assessing the exact reach and scope of that decision. In the meantime, disparities in municipal rules for industry operations are likely. Moreover, the Pennsylvania Supreme Court’s ruling may affect the annual impact fee on unconventional gas wells, as the fee was tied to municipal-ordinance uniformity.

Strategic determinations, including the allocation of capital and other resources to strategic opportunities, are challenging, and our failure to appropriately allocate capital and resources among our strategic opportunities may adversely affect our financial condition.

Our future growth prospects are dependent upon our ability to identify optimal strategies for our business. In developing our business plan, we considered allocating capital and other resources to various aspects of our businesses including well-development (primarily drilling), reserve acquisitions, exploratory activity, coal development, corporate items and other alternatives. We also considered our likely sources of capital. Notwithstanding the determinations made in the development of our business plan, business opportunities not previously identified periodically come to our attention, including possible acquisitions and dispositions. If we fail to identify optimal business strategies, or fail to optimize our capital investment and capital raising opportunities and the use of our other resources in furtherance of our business strategies, our financial condition and future growth may be adversely affected. Moreover, economic or other circumstances may change from those contemplated by our business plan, and our failure to recognize or respond to those changes may limit our ability to achieve our objectives.

Any failure by Murray Energy to satisfy the liabilities it assumed from us, as well as to perform its obligations under various agreements whose performance by Murray Energy we guaranteed to satisfy obligations, or under various agreements with us could materially increase our liabilities and materially adversely affect our results of operations, financial position and cash flows.

Murray Energy and its subsidiaries (Murray Energy) acquired approximately $2.4 billion of liabilities which had been reflected on our books. In addition to these assumed liabilities, (i) Murray Energy acquired our obligations under the multi-employer defined benefit pension plan for United Mine Workers of America (1974 Pension Plan), (ii) we guaranteed performance by Murray Energy under various West Virginia and Pennsylvania operational surety bonds and workers compensation obligations, under various equipment leases and to reclaim an impoundment site, and (iii) we leased or subleased various mining equipment to Murray Energy and we guaranteed performance by Murray Energy of certain coal supply agreements that Murray Energy acquired in the transaction. Our maximum estimated exposure under our Murray Energy guarantees as of December 31, 2013 was approximately $404 million. The leases and subleases we entered into with Murray Energy relate to approximately $200 million of equipment. Murray Energy also acquired retiree medical liabilities under the Coal Industry Retiree Health Benefits Act of 1992, for which Murray Energy is primarily liable, but CONSOL Energy remains secondarily liable. On November 12, 2013 in connection with the transaction, Moody’s assigned Murray Energy a family credit rating of B3 (speculative and subject to high credit risk) and its secured second lien notes due 2021 of Caa1(poor standing and subject to very high credit risk). Any failure by Murray Energy to satisfy these assumed liabilities or perform under these agreements could result in substantial claims against us by third parties and materially adversely affect our results of operations, financial position and cash flows. In addition, we will regularly evaluate the likelihood of default by Murray Energy under the guarantees we have provided. The results of the evaluation may materially impact our results of operations. If Murray Energy defaults under the obligations we guarantee our cash flows may also be materially impacted.

ITEM 1B. Unresolved Staff Comments

None.

ITEM 2. Properties

See “Coal Operations” and “Gas Operations” in Item 1 of this 10-K for a description of CONSOL Energy's properties.

ITEM 3. Legal Proceedings

The first through the sixth paragraphs of Note 24–Commitments and Contingent Liabilities in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K are incorporated herein by reference.

ITEM 4. Mine Safety and Health Administration Safety Data

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 is included in Exhibit 95 to this annual report.

PART II

ITEM 5. Market for Registrant's Common Equity and Related Stockholder Matters and Issuer Purchases of Equity Securities

Our common stock is listed on the New York Stock Exchange under the symbol CNX. The following table sets forth for the periods indicated the range of high and low sales prices per share of our common stock as reported on the New York Stock Exchange and the cash dividends declared on the common stock for the periods indicated:

	High	Low	Dividends
Year Period Ended December 31, 2013			
Quarter Ended March 31, 2013	$34.79	$29.91	$—
Quarter Ended June 30, 2013	$35.79	$27.10	$0.125
Quarter Ended September 30, 2013	$35.56	$26.51	$0.125
Quarter Ended December 31, 2013	$38.42	$33.99	$0.125
Year Period Ended December 31, 2012			
Quarter Ended March 31, 2012	$39.37	$31.72	$0.125
Quarter Ended June 30, 2012	$35.15	$26.80	$0.125
Quarter Ended September 30, 2012	$33.79	$27.83	$0.125
Quarter Ended December 31, 2012	$36.60	$29.71	$0.250

As of December 31, 2013, there were 162 holders of record of our common stock.

The following performance graph compares the yearly percentage change in the cumulative total shareholder return on the common stock of CONSOL Energy to the cumulative shareholder return for the same period of a peer group and the Standard & Poor's 500 Stock Index. The peer group is comprised of CONSOL Energy, Alpha Natural Resources Inc., Anadarko Petroleum Corp., Apache Corp., Arch Coal Inc., Chesapeake Energy Corp., Devon Energy Corp., EOG Resources Inc., Newfield Exploration Co., Noble Energy Inc., Peabody Energy Corp., Southwestern Energy Co., QEP Resources Inc., and WPX Energy, Inc. The graph assumes that the value of the investment in CONSOL Energy common stock and each index was $100 at December 31, 2008. The graph also assumes that all dividends were reinvested and that the investments were held through December 31, 2013.

	2008	2009	2010	2011	2012	2013
CONSOL Energy Inc.	100.0	175.6	173.3	132.1	117.8	141.0
Peer Group	100.0	149.0	167.3	140.2	131.4	151.2
S&P 500 Stock Index	100.0	63.4	79.8	91.7	104.0	134.8

Cumulative Total Shareholder Return Among CONSOL Energy Inc., Peer Group and S&P 500 Stock Index

The above information is being furnished pursuant to Regulation S-K, Item 201 (e) (Performance Graph).

The declaration and payment of dividends by CONSOL Energy is subject to the discretion of CONSOL Energy’s Board of Directors, and no assurance can be given that CONSOL Energy will pay dividends in the future. CONSOL Energy’s Board of Directors determines whether dividends will be paid quarterly. The determination to pay dividends will depend upon, among other things, general business conditions, CONSOL Energy’s financial results, contractual and legal restrictions regarding the payment of dividends by CONSOL Energy, planned investments by CONSOL Energy and such other factors as the Board of Directors deems relevant. Our credit facility limits our ability to pay dividends in excess of an annual rate of $0.40 per share when our leverage ratio exceeds 4.50 to 1.00 or our availability is less than or equal to $100 million. The leverage ratio was 5.14 to 1.00 and our availability was approximately $793 million at December 31, 2013. The credit facility does not permit dividend payments in the event of default. The indentures to the 2017, 2020 and 2021 notes limit dividends to $0.40 per share annually unless several conditions are met. Conditions include no defaults, ability to incur additional debt and other payment limitations under the indentures. There were no defaults in the year ended December 31, 2013.
See Part III, Item 12. “Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters” for information relating to CONSOL Energy's equity compensation plans.

ITEM 6. Selected Financial Data

The following table presents our selected consolidated financial and operating data for, and as of the end of, each of the periods indicated. The selected consolidated financial data for, and as of the end of, each of the years ended December 31, 2013, 2012, 2011, 2010 and 2009 are derived from our audited Consolidated Financial Statements. Certain reclassifications of prior year data have been made to conform to the year ended December 31, 2013 presentation. The selected consolidated financial and operating data are not necessarily indicative of the results that may be expected for any future period. The selected consolidated financial and operating data should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the financial statements and related notes included in this Annual Report.

	For the Years Ended December 31,				
	2013	2012	2011	2010	2009
Operating revenues from Continuing Operations	$3,120,722	$3,282,350	$4,237,913	$3,559,511	$3,202,549
Income from Continuing Operations	$79,264	$317,959	$681,675	$315,240	$515,700
Net Income Attributable to CONSOL Energy Inc. Shareholders	$660,442	$388,470	$632,497	$346,779	$539,717
Earnings per share:					
Basic:					
Income from Continuing Operations	$0.35	$1.40	$3.01	$1.41	$2.70
Income from Discontinued Operations	2.54	0.31	(0.22)	0.20	0.29
Net Income	$2.89	$1.71	$2.79	$1.61	$2.99
Dilutive:					
Income from Continuing Operations	$.35	$1.39	$2.98	$1.40	$2.67
Income from Discontinued Operations	2.52	0.31	(0.22)	0.20	0.28
Net Income	$2.87	$1.70	$2.76	$1.60	$2.95
Assets from Continuing Operations	$11,393,667	$10,383,343	$9,952,077	$9,543,457	$5,281,010
Assets from Discontinued Operations	—	2,614,251	2,573,623	2,527,153	2,494,391
Total assets	$11,393,667	$12,997,594	$12,525,700	$12,070,610	$7,775,401
Long-term debt from Continuing Operations (including current portion)	$3,175,014	$3,185,497	$3,196,455	$3,209,101	$465,975
Long-term debt from Discontinued Operations (including current portion)	—	2,574	1,659	1,820	2,327
Total Long-term debt (including current portion)	$3,175,014	$3,188,071	$3,198,114	$3,210,921	$468,302
Cash dividends declared per share of common stock	$0.375	$0.625	$0.425	$0.400	$0.400

See Item 1A, "Risk Factors" and Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" for a discussion of an adjustment to operating revenues for all periods and other matters that affect the comparability of the selected financial data as well as uncertainties that might affect the Company's future financial condition.

OTHER OPERATING DATA
(unaudited)

	Years Ended December 31,				
	2013	2012	2011	2010	2009
Gas:					
Net sales volumes produced (in billion cubic feet)	172.4	156.3	153.5	127.9	94.4
Average sales price ($ per Mcfe)(A)	$4.30	$4.22	$4.90	$5.83	$6.68
Average cost ($ per Mcfe)	$3.51	$3.37	$3.53	$3.54	$3.15
Proved reserves (in Bcfe) (B)	5,731	3,993	3,480	3,732	1,911
Coal:					
Tons sold from continuing operations (in thousands)(C)	28,776	27,612	32,090	32,280	32,185
Tons produced from continuing operations (in thousands)	28,476	27,178	31,721	31,895	32,987
Average sales price of tons produced ($ per ton produced)	$69.34	$77.75	$90.10	$73.31	$66.71
Average Cost of Goods Sold ($ per ton produced)	$50.78	$53.98	$51.88	$44.37	$41.76
Recoverable coal reserves (tons in millions)(D)	3,032	4,229	4,314	4,229	4,350
Number of active mining complexes (at end of period)	4	5	7	7	6

(A) Represents average net sales price including the effect of derivative transactions.
(B) Represents proved developed and undeveloped gas reserves at period end.
(C) Includes sales of coal produced by CONSOL Energy and purchased from third parties. Of the tons sold, CONSOL Energy purchased the following amount from third parties: 0.6 million tons, 0.5 million tons, 0.6 million tons, 0.2 million tons, and 0.3 million tons for the years ended December 31, 2013, 2012, 2011, 2010 and 2009, respectively.
(D) Represents proven and probable coal reserves at period end, excluding equity affiliates.

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

General

2013 Highlights

- Record total gas production of 172.4 Bcfe in 2013, 10% higher than 2012.
- Record Marcellus Shale production of 57.8 Bcfe in 2013, 58% higher than 2012.
- Completed a lease with the Allegheny County Airport Authority, which operates the Pittsburgh International Airport and the Allegheny County Airport, for the oil and gas rights on approximately 9.3 thousand acres. A majority of these contiguous acres are in the liquids area of the Marcellus Shale play. An up-front bonus payment of $46.3 million was paid at closing. Noble Energy, our joint venture partner, acquired 50% of the acres and accordingly, reimbursed CONSOL Energy for 50% of the associated costs. Approximately 7.6% of the bonus payment was placed into escrow while negotiations continue for a portion of the acres associated with the Allegheny County Airport and other acres that have potentially defective title. To date, less than 1% of this amount has been released from escrow. We must spud a well by February 21, 2015 and proceed with due diligence to complete the well or the lease terminates and the bonus is foregone.
- Entered into a farm-in agreement for approximately 90 thousand additional Marcellus Shale acres in West Virginia. Consideration of up to $190 million will be paid by CONSOL Energy in two installments: (i) 50% was paid at closing and (ii) the balance due over time as the acres are drilled. Closing occurred on December 5, 2013. Noble Energy, our Marcellus Shale joint venture partner, acquired a 50% interest in the acres and accordingly, will reimburse CONSOL Energy for 50% of the associated costs.
- Completed the sale of Consolidation Coal Company (CCC) and certain of its subsidiaries, which contains all five of CONSOL Energy's longwall coal mines in West Virginia, to a subsidiary of Murray Energy Corporation (Murray Energy). The CCC mines sold were McElroy Mine, Shoemaker Mine, Robinson Run Mine, Loveridge Mine, and Blacksville No. 2 Mine. Collectively, these mines produced 26.7 million tons of thermal coal in 2013 and 28.8 million tons of thermal coal in 2012. Murray Energy acquired approximately 1.1 billion tons of Pittsburgh No. 8 seam reserves. CONSOL Energy's River and Dock Operations were included in the transaction. CONSOL Energy received $850 million in cash as a result of the transaction. CONSOL Energy retained an overriding royalty interest in certain reserves sold in the transaction that included minimum royalty payments of $42 million. Additionally, Murray Energy acquired approximately $1.9 billion of other postretirement benefit plan liabilities, $100 million of workers compensation liabilities, $50 million of coal workers' pneumoconiosis liabilities, $10 million of long term disability liabilities, $155 million of environmental liabilities and CONSOL Energy's UMWA 1974 Pension Trust Obligations. The pre-tax financial gain resulting from the transaction was $1,035 million.
- In conjunction with the sale of CCC and certain of its subsidiaries, CONSOL Energy realigned its dividend policy to reflect the company's increased emphasis on growth. CONSOL Energy intends to pay a regular quarterly rate of $0.0625 per common share, or a 2014 annual rate of $0.25 per share, beginning with the first quarter of 2014.

2014 Expectations:

- Our 2014 annual gas production is expected to be between 215 - 235 Bcfe with annual production growth of 30% for 2015 and 2016.
- Our 2014 gas capital investment is expected to be $1,110 million.
- Our 2014 coal production is expected to be between 30.1 - 32.1 million tons.
- Our 2014 coal capital investment is expected to be $390 million.
- Pension settlement accounting may occur in 2014 related to staff reduction that occured in relation to the sale of CCC and certain subsidiaries.
- BMX Mine is expected to begin longwall mining during the first quarter of 2014.

Several significant transactions occurred in the year ended December 31, 2013. These events include the following:

Continuing Operations:

- In August 2013, CONSOL Energy completed the sale of its 50% interest in the CONSOL Energy/Devon Energy joint venture in Alberta, Canada. The properties and coal leases included were those related to Grassy Mountain, Bellevue, Adanac, and Lynx Creek (Crowsnest Pass). Cash proceeds for the sale were $24.7 million. The transaction resulted in a $15.3 million pre-tax gain on the sale of assets.

- On June 24, 2013, CONSOL Energy closed the sale of the Potomac coal reserves located in Grant and Tucker Counties in West Virginia. Cash proceeds from the sale were $25.0 million. The transaction resulted in a $24.7 million pre-tax gain on the sale of assets.
- Pension settlement accounting required the acceleration of previously unrecognized actuarial losses due to lump sum payments from the Company's qualified and non-qualified salary retirement pension plans exceeding the annual projected service and interest costs of the plans. The pension settlement resulted in a $39.5 million pre-tax expense adjustment. Many of the lump sum payments in the year ended December 31, 2013 were paid to employees who elected to retire under the 2012 Voluntary Severance Incentive Plan.
- A review of certain titles in the Company's Marcellus Shale acreage, continued throughout the year ended December 31, 2013. As a result of the Company's review of the title defects, asserted by its joint venture partner Noble Energy, and working in collaboration with Noble, CONSOL Energy has conceded defects on acreage with a value of $23.1 million. See Note 11- Property, Plant and Equipment, in the Notes to the Audited Consolidated Financial Statements included in this Form 10-K for additional details.
- In the year ended December 31, 2013, an agreement was reached for resolution of the class actions brought by shareholders of CNX Gas alleging that the price paid by CONSOL Energy to acquire all the shares of CNX Gas common stock that CONSOL Energy did not already own for $38.25 per share in May 2010 was not fair. The total settlement provided for a payment to the plaintiffs of $42.7 million, of which the CONSOL Energy’s portion was $19.2 million. See Note 24 - Commitments and Contingencies, in the Notes to the Audited Consolidated Financial Statements included in this Form 10-K for additional details.

Discontinued Operations:

- On March 12, 2013, smoke was detected exiting the Orndoff shaft at CONSOL Energy's Blacksville No. 2 Mine near Wayne in Greene County, Pennsylvania. All day shift underground employees were safely evacuated and no one sustained injuries. The location of the fire was identified and containment and extinguishment procedures were followed. The fire was successfully extinguished and the longwall restarted May 20, 2013. This event resulted in a pre-tax expense of $34.3 million in the year ended December 31, 2013.
- Severance and related costs of $9.5 million pre-tax expense related to the change in control of the 5 coal mines and the reduction of supporting administrative staff was reflected in the 2013 financial results.
- Settlement and curtailment gains totaling $1.6 billion were recognized related to the company’s obligations under the Other Postretirement Benefits, Workers’ Compensation, Pension, Coal Workers’ Pneumoconiosis, and Long-Term Disability plans as a result of the sale to Murray Energy.

Results of Operations
Year Ended December 31, 2013 Compared with Year Ended December 31, 2012

Net Income Attributable to CONSOL Energy Shareholders
CONSOL Energy reported net income attributable to CONSOL Energy shareholders of $660 million, or $2.87 per diluted share, for the year ended December 31, 2013. Net income attributable to CONSOL Energy shareholders was $388 million, or $1.70 per diluted share, for the year ended December 31, 2012. Included in net income is income from continuing operations of $79 million, or $0.35 per diluted share, for the year ended December 31, 2013. Income from continuing operations was $318 million, or $1.39 per diluted share, for the year ended December 31, 2012. Also included in net income is income from discontinued operations of $580 million, or $2.52 per diluted share, for the year ended December 31, 2013. Income from discontinued operations was $70 million, or $0.31 per diluted share, for the year ended December 31, 2012.

The total gas division includes Marcellus, coalbed methane (CBM), shallow oil and gas, and other gas. The total gas division contributed a loss of $2 million before income tax for the year ended December 31, 2013 compared to $39 million of earnings before income tax for the year ended December 31, 2012. Total gas production was 172.4 Bcfe for the year ended December 31, 2013 compared to 156.3 Bcfe for the year ended December 31, 2012.

The following table presents a breakout of net liquid and natural gas sales information to assist in the understanding of the Company's production and sales portfolio:

	For the Years Ended December 31,			
in thousands (unless noted)	2013	2012	Variance	Percent Change
LIQUIDS				
NGLs:				
Sales Volume (MMcfe)	2,628	610	2,018	330.8 %
Sales Volume (Mbbls)	438	102	336	329.4 %
Gross Price ($/Bbl)	$ 53.76	$ 52.32	$ 1.44	2.8 %
Gross Revenue	$ 23,541	$ 5,314	$ 18,227	343.0 %
Oil:				
Sales Volume (MMcfe)	634	600	34	5.7 %
Sales Volume (Mbbls)	106	100	6	6.0 %
Gross Price ($/Bbl)	$ 89.58	$ 92.58	$ (3.00)	(3.2)%
Gross Revenue	$ 9,469	$ 9,252	$ 217	2.3 %
Condensate:				
Sales Volume (MMcfe)	381	63	318	504.8 %
Sales Volume (Mbbls)	64	11	53	481.8 %
Gross Price ($/Bbl)	$ 81.06	$ 78.84	$ 2.22	2.8 %
Gross Revenue	$ 5,158	$ 823	$ 4,335	526.7 %
GAS				
Sales Volume (MMcf)	168,737	155,052	13,685	8.8 %
Sales Price ($/Mcf)	$ 3.71	$ 2.94	$ 0.77	26.2 %
Hedging Impact ($/Mcf)	$ 0.45	$ 1.22	$ (0.77)	(63.1)%
Gross Revenue	$ 702,700	$ 645,053	$ 57,647	8.9 %

The average sales price and average costs for all active gas operations were as follows:

	For the Years Ended December 31,			
	2013	2012	Variance	Percent Change
Average Sales Price (per Mcfe)	$4.30	$4.22	$0.08	1.9 %
Average Costs (per Mcfe)	3.51	3.37	0.14	4.2 %
Margin	$0.79	$0.85	$(0.06)	(7.1)%

Total gas division outside sales revenues were $741 million for the year ended December 31, 2013 compared to $659 million for the year ended December 31, 2012. The increase was primarily due to the 10.3% increase in total volumes sold, along with a 1.9% increase in average price per Mcfe. The increase in average sales price is the result of an increase in general market prices and the increase in sales of natural gas liquids and condensate. The increase was offset, in part, by various gas swap transactions that occurred throughout both periods. The gas swap transactions qualify as financial cash flow hedges that exist parallel to the underlying physical transactions. These financial hedges represented approximately 84.3 Bcf of our produced gas sales volumes for the year ended December 31, 2013 at an average price of $4.68 per Mcf. These financial hedges represented 76.9 Bcf of our produced gas sales volumes for the year ended December 31, 2012 at an average price of $5.25 per Mcf.

Changes in the average cost per Mcfe of gas sold were primarily related to the following items:

- Gathering costs increased in the period-to-period comparison due to a $0.04 per Mcfe increase in processing fees associated with natural gas liquids and a $0.10 per Mcfe increase in firm transportation costs.
- Depreciation, depletion and amortization rates increased due to higher units-of-production for producing properties in the period to period comparison offset, in part, by additional volumes.
- These increases were offset, in part, by higher volumes in the period-to-period comparison due to the on-going Marcellus drilling program. Fixed costs are allocated over increased volumes, resulting in lower unit costs.

The coal division includes thermal coal, high volatile metallurgical coal, low volatile metallurgical coal and other coal. The total coal division contributed $337 million of earnings before income tax for the year ended December 31, 2013 compared to $592 million for the year ended December 31, 2012. The total coal division sold 28.8 million tons of coal produced from CONSOL Energy mines, for the year ended December 31, 2013 compared to 27.6 million tons for the year ended December 31, 2012.

The average sales price and average cost of goods sold per ton for continuing coal operations were as follows:

	For the Years Ended December 31,			
	2013	2012	Variance	Percent Change
Average Sales Price per ton sold	$69.34	$77.75	$(8.41)	(10.8)%
Average Costs of Goods Sold per ton	50.78	53.98	(3.20)	(5.9)%
Margin	$18.56	$23.77	$(5.21)	(21.9)%

The lower average sales price per ton sold reflects a decrease in the global metallurgical coal markets. The coal division priced 7.9 million tons on the export market at an average sales price of $72.27 per ton for the year ended December 31, 2013 compared to 7.5 million tons at an average price of $83.67 per ton for the year ended December 31, 2012. All other tons were sold on the domestic market.

Changes in the average cost of goods sold per ton were primarily related to the following items:

- Average cost of goods sold decreased due to an increase in tons sold. Fixed costs are allocated over more sales tons, resulting in lower unit costs.
-

On July 27, 2012, a structural failure occurred at the Bailey Preparation Plant in Southwestern Pennsylvania. The belt system conveys coal from both the Bailey and Enlow Fork Mines to the Bailey Preparation Plant. The incident caused a total of four longwalls to be idled for approximately three weeks, and production to be at approximately 60% for the third quarter of 2012. The mines operated at full capacity for the entire 2013 period, which resulted in lower direct operating costs per ton produced.

- The Fola Mining Complex was idled in August 2012 which resulted in lower direct operating costs per ton produced in the period-to-period comparison. The mine, which was idled for market reasons, was a higher cost mining operation which when removed reduced the overall average direct operating costs per ton produced.
- Direct services to operations are improved primarily due to a reduction in subsidence expenses related to the timing and nature of properties and streams undermined as well as a reduction in direct administration employees as a result of the 2012 Voluntary Severance Incentive Plan discussed below under general and administrative costs.
- Depreciation, depletion and amortization was improved primarily due to the idling of operations at the Fola Mining Complex in August 2012. The improvements were offset, in part, by higher costs in the 2013 period related to Bailey, Enlow Fork, and Buchanan Mines running for the full year in 2013 compared to being idled at various times throughout 2012.
- Average direct operating costs were impaired due to CONSOL Energy entering into a new longwall lease in 2013 at our Bailey Mine.
- Costs were impaired in the current period due to the idling of the Buchanan Mine for various months throughout 2012. Although idled at times during 2012, the Buchanan Mine ran the continuous miners and worked on various projects which increased overall 2012 unit costs.

The other segment includes industrial supplies activity, coal terminal activity, income taxes and other business activities not assigned to the gas or coal segment.

General and Administrative costs for continuing operations are allocated between divisions (Coal, Gas, Other) based primarily on percentage of total revenue and percentage of total projected capital expenditures. General and Administrative costs are excluded from the coal and gas unit costs above. Total General and Administrative costs from continuing operations were made up of the following items:

	For the Years Ended December 31,			
	2013	2012	Variance	Percent Change
Contributions	$7	$9	$(2)	(22.2)%
Employee Wages and Related Expenses	33	35	(2)	(5.7)%
Advertising and Promotion	4	4	—	— %
Consulting and Professional Services	21	14	7	50.0 %
Miscellaneous	17	17	—	— %
Total Company General and Administrative Expenses	$82	$79	$3	3.8 %

Total Company General and Administrative Expenses changed due to the following:

- Contributions decreased $2 million related to various transactions that occurred throughout both periods, none of which were individually material.
- Employee wages and related expenses decreased $2 million primarily attributable to fewer employees as a result of the 2012 Voluntary Severance Incentive Plan, as previously discussed. There was also lower salary other post-employment benefit (OPEB) expenses in the period-to-period comparison related to changes in the discount rates and other assumptions.
- Advertising and promotion remained consistent in the period-to-period comparison.
- Consulting and professional services increased $7 million in the period-to-period comparison. Various legal proceedings accounted for $3 million of the increase and an additional $2 million was related to tax advisory services. The remaining increase was due to various other corporate initiatives, none of which were individually significant.
- Miscellaneous general and administrative expenses remained consistent in the period-to-period comparison.

Total Company long-term liabilities for continuing operations, such as OPEB, the salary retirement plan, workers' compensation and long-term disability are actuarially calculated for the Company as a whole. The expenses are then allocated to operational units based on active employee counts or active salary dollars. Total CONSOL Energy continuing operations expense related to our actuarial liabilities was $166 million for the year ended December 31, 2013 compared to $148 million for the year ended December 31, 2012. The increase of $18 million for total CONSOL Energy continuing operations expense was primarily due to required pension settlement accounting which resulted in $39 million of expense. Pension settlement expenses were required when lump sum distributions made for the 2013 plan year exceeded the total of the service cost and interest cost for the 2013 plan year. The pension settlement was not allocated to individual operating segments and is therefore not included in unit costs presented for gas or coal. This was offset, in part, due to a modification of the salaried post-employment benefit plan and an increase in the discount rate assumptions used to calculate expense for benefit plans at the measurement date, which is December 31. See Note 16 - Pension and Other Post-Employment Benefit Plans and Note 17 - Coal Workers' Pneumoconiosis (CWP) and Workers' Compensation Net Periodic Benefit Costs in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional detail of the total Company expense increase.

TOTAL GAS SEGMENT ANALYSIS for the year ended December 31, 2013 compared to the year ended December 31, 2012:
The gas segment had a loss before income tax of $2 million for the year ended December 31, 2013 compared to a earnings before income tax of $39 million for the year ended December 31, 2012.

	For the Year Ended December 31, 2013					Difference to Year Ended December 31, 2012				
	Marcellus	CBM	Shallow Oil and Gas	Other Gas	Total Gas	Marcellus	CBM	Shallow Oil and Gas	Other Gas	Total Gas
Sales:										
Produced	$252	$336	$131	$19	$738	$118	$(42)	$(4)	$9	$81
Related Party	—	3	—	—	3	—	1	—	—	1
Total Outside Sales	252	339	131	19	741	118	(41)	(4)	9	82
Gas Royalty Interest	—	—	—	63	63	—	—	—	13	13
Purchased Gas	—	—	—	7	7	—	—	—	4	4
Other Income	—	—	—	58	58	—	—	—	1	1
Total Revenue and Other Income	252	339	131	147	869	118	(41)	(4)	27	100
Lifting	20	37	35	5	97	8	—	(5)	3	6
Ad Valorem, Severance, and Other Taxes	9	9	10	1	29	5	(1)	—	(1)	3
Gathering	50	114	34	3	201	26	8	8	(2)	40
Gas Direct Administrative, Selling & Other	26	8	10	5	49	9	(6)	(3)	2	2
Depreciation, Depletion and Amortization	67	90	60	13	230	20	3	1	4	28
General & Administration	—	—	—	45	45	—	—	—	5	5
Gas Royalty Interest	—	—	—	53	53	—	—	—	14	14
Purchased Gas	—	—	—	5	5	—	—	—	2	2
Exploration and Other Costs	—	—	—	61	61	—	—	—	22	22
Other Corporate Expenses	—	—	—	92	92	—	—	—	15	15
Interest Expense	—	—	—	9	9	—	—	—	4	4
Total Cost	172	258	149	292	871	68	4	1	68	141
Earnings (Loss) Before Income Tax	80	81	(18)	(145)	(2)	50	(45)	(5)	(41)	(41)

54

MARCELLUS GAS SEGMENT

The Marcellus segment contributed $80 million to the total Company earnings before income tax for the year ended December 31, 2013 compared to $30 million for the year ended December 31, 2012.

	For the Years Ended December 31,			
	2013	2012	Variance	Percent Change
Marcellus Gas Sales Volumes (Bcf)	55.0	35.9	19.1	53.2 %
NGLs Sales Volumes (Bcfe)*	2.5	0.6	1.9	316.7 %
Condensate Sales Volumes (Bcfe)*	0.3	—	0.3	100.0 %
Total Marcellus Gas Sales Volumes (Bcfe)*	57.8	36.5	21.3	58.4 %
Average Sales Price - Gas (Mcf)	$3.77	$2.89	$0.88	30.4 %
Hedging Impact - Gas (Mcf)	$0.32	$0.69	$(0.37)	(53.6)%
Average Sales Price - NGLs (Mcfe)*	$9.09	$8.68	$0.41	4.7 %
Average Sales Price - Condensate (Mcfe)*	$13.73	$13.54	$0.19	1.4 %
Total Average Marcellus sales (per Mcfe)	$4.35	$3.68	$0.67	18.2 %
Average Marcellus lifting costs (per Mcfe)	$0.35	$0.34	$0.01	2.9 %
Average Marcellus ad valorem, severance, and other taxes (per Mcfe)	$0.16	$0.12	$0.04	33.3 %
Average Marcellus gathering costs (per Mcfe)	$0.86	$0.67	$0.19	28.4 %
Average Marcellus direct administrative, selling & costs (per Mcfe)	$0.45	$0.46	$(0.01)	(2.2)%
Average Marcellus depreciation, depletion and amortization costs (per Mcfe)	$1.16	$1.30	$(0.14)	(10.8)%
Total Average Marcellus costs (per Mcfe)	$2.98	$2.89	$0.09	3.1 %
Average Margin for Marcellus (per Mcfe)	$1.37	$0.79	$0.58	73.4 %

* NGLs, and Condensate are converted to Mcfe at the rate of one barrel equals six Mcf based upon the approximate relative energy content of oil and natural gas,which is not indicative of the relationship of oil, NGLs, condensate, and natural gas prices.

The Marcellus segment sales revenues were $252 million for the year ended December 31, 2013 compared to $134 million for the year ended December 31, 2012. The $118 million increase is primarily due to a 58.4% increase in total volumes sold, and an 18.2% increase in total average sales prices in the period-to-period comparison. The increase in sales volumes is primarily due to additional wells coming on-line from our on-going drilling program. The increase in Marcellus total average sales price was the result of the $0.88 per Mcf increase in gas market prices, along with a $0.16 per Mcf increase due to the 2.2 Bcfe additional natural gas liquids and condensate sales volumes. The increase was offset, in part, by a $0.37 per Mcf decrease resulting from various gas swap transactions that settled in the year ended December 31, 2013 compared to the 2012 period. These gas swap transactions qualify as financial cash flow hedges that exist parallel to the underlying physical transactions. These financial hedges represented approximately 21.6 Bcf of our produced Marcellus gas sales volumes for the year ended December 31, 2013 at an average price of $4.67 per Mcf. For the year ended December 31, 2012, these financial hedges represented 12.4 Bcf at an average price of $4.99 per Mcf.

Total costs for the Marcellus segment were $172 million for the year ended December 31, 2013 compared to $104 million for the year ended December 31, 2012. The increase in total dollars and unit costs for the Marcellus segment are due to the following items:

•Marcellus lifting costs were $20 million for the year ended December 31, 2013 compared to $12 million for the year ended December 31, 2012. The increase primarily relates to an increase in sales volumes, along with an increase in salt water disposal costs, road maintenance costs, and well tending costs. The impact on average unit costs from these increases was offset by higher sales volumes.

•Marcellus ad valorem, severance and other taxes were $9 million for the year ended December 31, 2013 compared to $4 million for the year ended December 31, 2012. The increase in total dollars and unit costs is primarily due to an increase in severance tax expense caused by higher average gas sales prices and the 58.4% increase in sales volumes during the current period.

•Marcellus gathering costs were $50 million for the year ended December 31, 2013 compared to $24 million for the year ended December 31, 2012. Total dollars increased due to an increase in processing fees associated with natural gas liquids, which resulted in a $0.12 per Mcfe increase in average unit costs. Higher firm transportation costs also resulted in an increase on unit costs. The impact on average unit costs from these increases was offset, in party, by higher sales volumes.

•Marcellus direct administrative, selling and other costs were $26 million for the year ended December 31, 2013 compared to $17 million for the year ended December 31, 2012. Direct administrative, selling and other costs attributable to the total gas segment are allocated to the individual gas segments based on a combination of production and employee counts. The increase in direct administrative, selling & other costs was primarily due to Marcellus volumes representing a larger proportion of CONSOL Energy's total gas sales volumes. The impact on average unit costs from the increase in direct administrative costs was offset by higher sales volumes.

•Depreciation, depletion and amortization costs were $67 million for the year ended December 31, 2013 compared to $47 million for the year ended December 31, 2012. There was approximately $66 million, or $1.14 per unit-of-production, of depreciation, depletion and amortization related to Marcellus gas and related well equipment that was reflected on a units-of-production method of depreciation in the year ended December 31, 2013. There was approximately $44 million, or $1.24 per unit-of-production, of depreciation, depletion and amortization related to Marcellus gas and related well equipment that was reflected on a units-of-production method of depreciation for the year ended December 31, 2012. There was approximately $1 million, or $0.02 per Mcf, of depreciation, depletion and amortization related to gathering and other equipment that was reflected on a straight line basis for the year ended December 31, 2013. There was $3 million, or $0.06 per Mcf, of depreciation, depletion and amortization related to gathering and other equipment reflected on a straight line basis for the year ended December 31, 2012.

COALBED METHANE (CBM) GAS SEGMENT

The CBM segment contributed $81 million to the total Company earnings before income tax for the year ended December 31, 2013 compared to $126 million for the year ended December 31, 2012.

	For the Years Ended December 31,			
	2013	2012	Variance	Percent Change
CBM Gas Sales Volumes (Bcf)	82.9	88.2	(5.3)	(6.0)%
Average Sales Price - Gas (Mcf)	$3.69	$2.88	$0.81	28.1 %
Hedging Impact - Gas (Mcf)	$0.40	$1.44	$(1.04)	(72.2)%
Total Average CBM sales price (per Mcf)	$4.09	$4.32	$(0.23)	(5.3)%
Average CBM lifting costs (per Mcf)	$0.44	$0.42	$0.02	4.8 %
Average CBM ad valorem, severance, and other taxes (per Mcf)	$0.10	$0.12	$(0.02)	(16.7)%
Average CBM gathering costs (per Mcf)	$1.37	$1.21	$0.16	13.2 %
Average CBM direct administrative, selling & other costs (per Mcf)	$0.10	$0.16	$(0.06)	(37.5)%
Average CBM depreciation, depletion and amortization costs (per Mcf)	$1.10	$0.98	$0.12	12.2 %
Total Average CBM costs (per Mcf)	$3.11	$2.89	$0.22	7.6 %
Average Margin for CBM (per Mcf)	$0.98	$1.43	$(0.45)	(31.5)%

CBM sales revenues were $339 million in the year ended December 31, 2013 compared to $380 million for the year ended December 31, 2012. The $41 million decrease was primarily due to a 6.0% decrease in total volumes sold and a 5.3% decrease in total average sales price per Mcf. CBM sales volumes decreased 5.3 Bcf for the year ended December 31, 2013 compared to the 2012 period primarily due to normal well declines and fewer CBM wells being drilled in the 2013 period. Currently, the focus of the gas division is to develop its Marcellus and Utica acreage. The

CBM total average sales price decreased $1.04 due to various gas swap transactions that matured in each period. These gas swap transactions qualify as financial cash flow hedges that exist parallel to the underlying physical transactions. Financial hedges represented approximately 48.3 Bcf of our produced CBM gas sales volumes for the year ended December 31, 2013 at an average price of $4.54 per Mcf. For the year ended December 31, 2012, these financial hedges represented 45.8 Bcf at an average price of $5.34 per Mcf. The decrease was offset, in part, by a $0.81 per Mcf increase in average gas market prices.

Total costs for the CBM segment were $258 million for the year ended December 31, 2013 compared to $254 million for the year ended December 31, 2012. The increase in total dollars and unit costs for the CBM segment are due to the following items:

•CBM lifting costs were $37 million for the year ended December 31, 2013 compared to $37 million for the year ended December 31, 2012. The decrease in total dollars was primarily due to lower road maintenance and lower contractor services in the period-to-period comparison. The increase in unit costs was due to the decrease in gas sales volumes and was offset, in part, by the decrease in total costs.

•CBM ad valorem, severance and other taxes were $9 million for the year ended December 31, 2013 compared to $10 million for the year ended December 31, 2012. The decrease of $1 million was primarily due to a reassement of our ad valorem taxes paid to Tazewell County, Virginia resulting in a current year refund. The decrease was offset, in part, by an increase in severance tax expense resulting from the increase in average sales price, without the impact of hedging, as described above.

•CBM gathering costs were $114 million for the year ended December 31, 2013 compared to $106 million for the year ended December 31, 2012. The increase in total dollars and average per unit costs was due to increased compression costs, increased power fees, and increased pipeline and road maintenance. Unit costs were also negatively impacted by the decrease in gas sales volumes.

•CBM direct administrative, selling and other costs were $8 million for the year ended December 31, 2013 compared to $14 million for the year ended December 31, 2012. Direct administrative, selling & other costs attributable to the total gas segment are allocated to the individual gas segments based on a combination of production and employee counts. The decrease in direct administrative, selling & other costs was primarily due to reduced direct administrative labor and CBM volumes representing a smaller proportion of CONSOL Energy's total gas sales volumes. Improvements in unit costs were offset, in part, by the decrease in gas sales volumes.

•Depreciation, depletion and amortization attributable to the CBM segment was $90 million for the year ended December 31, 2013 compared to $87 million for the year ended December 31, 2012. There was approximately $62 million, or $0.77 per unit-of-production, of depreciation, depletion and amortization related to CBM gas and related well equipment that was reflected on a units-of-production method of depreciation in the year ended December 31, 2013. The production portion of depreciation, depletion and amortization was $60 million, or $0.67 per unit-of-production in the year ended December 31, 2012. There was approximately $28 million, or $0.33 per Mcf of depreciation, depletion and amortization related to gathering and other equipment reflected on a straight line basis for the year ended December 31, 2013. The non-production related depreciation, depletion and amortization was $28 million, or $0.31 per Mcf for the year ended December 31, 2012.

SHALLOW OIL AND GAS SEGMENT

The shallow oil and gas segment had a loss before income tax of $18 million for the year ended December 31, 2013 compared to a loss before income tax of $13 million for the year ended December 31, 2012.

	For the Years Ended December 31,			
	2013	2012	Variance	Percent Change
Shallow Oil and Gas Sales Volumes (Bcf)	27.5	28.7	(1.2)	(4.2)%
Oil Sales Volumes (Bcfe)*	0.4	0.5	(0.1)	(20.0)%
Total Shallow Oil and Gas Sales Volumes (Bcfe)*	27.9	29.2	(1.3)	(4.5)%
Average Sales Price - Gas (Mcf)	$3.66	$3.12	$0.54	17.3 %
Hedging Impact - Gas (Mcf)	$0.89	$1.33	$(0.44)	(33.1)%
Average Sales Price - Oil (Mcfe)*	$14.42	$15.65	$(1.23)	(7.9)%
Total Average Shallow Oil and Gas sales price (per Mcfe)	$4.70	$4.64	$0.06	1.3 %
Average Shallow Oil and Gas lifting costs (per Mcfe)	$1.28	$1.37	$(0.09)	(6.6)%
Average Shallow Oil and Gas ad valorem, Severance, and other taxes (per Mcfe)	$0.36	$0.35	$0.01	2.9 %
Average Shallow Oil and Gas gathering costs (per Mcfe)	$1.21	$0.92	$0.29	31.5 %
Average Shallow Oil and Gas direct administrative, selling & other costs (per Mcfe)	$0.35	$0.45	$(0.10)	(22.2)%
Average Shallow Oil and Gas depreciation, depletion and amortization costs (per Mcfe)	$2.14	$2.02	$0.12	5.9 %
Total Average Shallow Oil and Gas costs (per Mcfe)	$5.34	$5.11	$0.23	4.5 %
Average Margin for Shallow Oil and Gas (per Mcfe)	$(0.64)	$(0.47)	$(0.17)	36.2 %

*Oil, NGLs, and Condensate are converted to Mcfe at the rate of one barrel equals six mcf based upon the approximate relative energy content of oil and natural gas,which is not indicative of the relationship of oil, NGLs, condensate, and natural gas prices.

Shallow Oil and Gas sales revenues were $131 million for the year ended December 31, 2013 compared to $135 million for the year ended December 31, 2012. The $4 million decrease was primarily due to the 4.5% decrease in total volumes sold, offset, in part, by a 1.3% increase in the total average sales price. The increase in shallow oil and gas total average sales price is primarily the result of a $0.54 per Mcf increase in average market prices offset, in part, by a $0.44 per Mcf decrease due to various gas swap transactions that matured in each period. These gas swap transactions qualify as financial cash flow hedges that exist parallel to the underlying physical transactions. These financial hedges represented approximately 14.3 Bcf of our produced shallow oil and gas sales volumes for the year ended December 31, 2013 at an average price of $5.20 per Mcf. For the year ended December 31, 2012, these financial hedges represented 18.5 Bcf at an average price of $5.23 per Mcf. The hedging impact on the average sales price was a decrease of $0.44 per Mcf.

Total costs for the shallow oil and gas segment were $149 million for the year ended December 31, 2013 compared to $148 million for the year ended December 31, 2012. The increase in total dollars and unit costs for the shallow oil and gas segment are due to the following items:

•Shallow Oil and Gas lifting costs were $35 million for the year ended December 31, 2013 compared to $40 million for the year ended December 31, 2012. The $5 million decrease in total costs and $0.09 per Mcfe decrease in average unit costs is due to lower well tending costs, and lower salt water disposal costs offset, in part, by an increase in accretion expense on the well plugging liability. The related decrease in unit costs is offset, in part, by the decrease in sales volumes.

•Shallow Oil and Gas ad valorem, severance and other taxes remained consistent at $10 million for the year ended December 31, 2013 and 2012. The increase of $0.01 per Mcfe in unit costs was due to the decrease in sales volumes.

•Shallow Oil and Gas gathering costs were $34 million for the year ended December 31, 2013 compared to $26 million for the year ended December 31, 2012. Gathering costs increased $8 million primarily due to increased firm transportation costs in the period-to-period comparison. Unit costs were further impacted by lower sales volumes.

•Shallow Oil and Gas direct administrative, selling and other costs were $10 million for the year ended December 31, 2013 compared to $13 million for the year ended December 31, 2012. Direct administrative, selling and other costs attributable to the total gas segment are allocated to the individual gas segments based on a combination of production and employee counts. The $3 million decrease in the period-to-period comparison is due to reduced direct administrative labor and Shallow Oil and Gas volumes representing a smaller proportion of CONSOL Energy's total gas sales volumes. These decreases in costs were offset, in part, by lower sales volumes.

•Depreciation, depletion and amortization attributable to the Shallow Oil & Gas segment was $60 million for the year ended December 31, 2013 compared to $59 million for the year ended December 31, 2012 There was approximately $52 million, or $1.87 per unit-of production, of depreciation, depletion and amortization related to Shallow Oil and Gas gas and related well equipment that was reflected on a units-of-production method of depreciation for the year ended December 31, 2013. There was approximately $51 million, or $1.75 per unit-of-production, of depreciation, depletion and amortization related to Shallow Oil and Gas gas and related well equipment that was reflected on a units-of-production method of depreciation for the year ended December 31, 2012. There was approximately $8 million, or $0.27 per Mcf, of depreciation, depletion and amortization related to gathering and other equipment that is reflected on a straight-line basis for the year ended December 31, 2013. There was $8 million, or $0.27 per Mcf, of depreciation, depletion and amortization related to gathering and other equipment that is reflected on a straight-line basis for the year ended December 31, 2012.

OTHER GAS SEGMENT

The other gas segment includes activity not assigned to the Marcellus, CBM, or shallow oil & gas segments. This segment includes purchased gas activity, gas royalty interest activity, exploration and other costs, other corporate expenses, and miscellaneous operational activity not assigned to a specific gas segment.
Other gas sales volumes are primarily related to production from the Chattanooga Shale in Tennessee and the Utica Shale in Ohio. Revenue from these operations were approximately $19 million for the year ended December 31, 2013 and $10 million for the year ended December 31, 2012. Total costs related to these other sales were $27 million for the year ended December 31, 2013 and $21 million for the year ended December 31, 2012. A per unit analysis of the other operating costs in Chattanooga Shale and Utica Shale is not meaningful due to the relatively low volumes sold in the period-to-period analysis.
Royalty interest gas sales represent the revenues related to the portion of production belonging to royalty interest owners sold by the CONSOL Energy gas segment. Royalty interest gas sales revenue was $63 million for the year ended December 31, 2013 compared to $50 million for the year ended December 31, 2012. The changes in market prices, contractual differences among leases, and the mix of average and index prices used in calculating royalties contributed to the period-to-period increase.

	For the Years Ended December 31,			
	2013	2012	Variance	Percent Change
Gas Royalty Interest Sales Volumes (Bcf)	15.3	18.0	(2.7)	(15.0)%
Average Sales Price (per Mcf)	$4.13	$2.74	$1.39	50.7%

Purchased gas sales volumes represent volumes of gas sold at market prices that were purchased from third-party producers. Purchased gas sales revenues were $7 million for the year ended December 31, 2013 compared to $3 million for the year ended December 31, 2012.

	For the Years Ended December 31,			
	2013	2012	Variance	Percent Change
Purchased Gas Sales Volumes (Bcf)	1.6	1.1	0.5	45.5%

Average Sales Price (per Mcf)	$4.12	$3.03	$1.09	36.0	%

Other income was $58 million for the year ended December 31, 2013 compared to $57 million for the year ended December 31, 2012. The $1 million change was due to various transactions that occurred throughout both periods, none of which were individually material.

General and Administrative costs are allocated to the total gas segment based on percentage of total revenue and percentage of total projected capital expenditures. Costs were $45 million for the year ended December 31, 2013 and $40 million for the year ended December 31, 2012. Refer to the discussion of total company general and administrative costs contained in the section "Net Income Attributable to CONSOL Energy Shareholders" of this quarterly report for a detailed cost explanation.

Royalty interest gas costs represent the costs related to the portion of production belonging to royalty interest owners sold by the CONSOL Energy gas segment. Royalty interest gas costs were $53 million for the year ended December 31, 2013 compared to $39 million for the year ended December 31, 2012. The changes in market prices, contractual differences among leases, and the mix of average and index prices used in calculating royalties contributed to the period-to-period change.

	For the Years Ended December 31,			
	2013	2012	Variance	Percent Change
Gas Royalty Interest Sales Volumes (Bcf)	15.3	18.0	(2.7)	(15.0)%
Average Cost (per Mcf)	$3.47	$2.16	$1.31	60.6%

Purchased gas volumes represent volumes of gas purchased from third-party producers that are subsequently sold to customers. Changes in the average cost per Mcf were due to overall price changes and contractual differences among customers in the period-to-period comparison. Purchased gas costs were $5 million for the year ended December 31, 2013 compared to $3 million for the year ended December 31, 2012.

	For the Years Ended December 31,			
	2013	2012	Variance	Percent Change
Purchased Gas Sales Volumes (Bcf)	1.6	1.1	0.5	45.5%
Average Cost (per Mcf)	$3.05	$2.44	$0.61	25.0%

Exploration and other costs were $61 million for the year ended December 31, 2013 compared to $39 million for the year ended December 31, 2012. The $22 million increase in costs is primarily related to the following items:

	For the Years Ended December 31,			
	2013	2012	Variance	Percent Change
Marcellus Title Defects	$23	$4	$19	475.0%
Dry Hole Costs	8	3	5	166.7%
Exploration Costs	20	18	2	11.1%
Lease Expiration Costs	10	14	(4)	(28.6)%
Total Exploration and Other Costs	$61	$39	$22	56.4%

- CONSOL Energy has completed its review of the title defect notice, asserted by Noble, and working in collaboration with Noble, conceded title defects on acreage which had a carrying value to CONSOL Energy of $23 million for the year ended December 31, 2013 compared to $4 million for the year ended December 31, 2012.
- Dry hole costs increased $5 million due to various transactions that occurred throughout both periods, none of which were individually material.
- Exploration expense increased $2 million due to increased exploratory expenses associated primarily with the Utica operating areas and various transactions that occurred throughout both periods, none of which were individually material.
- Lease expiration costs relate to locations where CONSOL Energy allowed the primary term lease to expire because of unfavorable drilling economics. The $4 million decrease is due to fewer lease expirations in the current period when compared with the prior period.

Other corporate expenses were $92 million for the year ended December 31, 2013 compared to $77 million for the year ended December 31, 2012. The $15 million increase in the period-to-period comparison was made up of the following items:

	For the Years Ended December 31,			
	2013	2012	Variance	Percent Change
Unutilized firm transportation	$35	$16	$19	118.8 %
Stock-based compensation	24	18	6	33.3 %
Bank fees	7	7	—	— %
Short-term incentive compensation	20	26	(6)	(23.1)%
PA Impact fees	—	4	(4)	(100.0)%
Other	6	6	—	— %
Total Other Corporate Expenses	$92	$77	$15	19.5 %

- Unutilized firm transportation costs represent pipeline transportation capacity the gas segment has obtained to enable gas production to flow uninterrupted as sales volumes increase, as well as additional processing capacity for natural gas liquids. The $19 million increase is due to increased firm transportation capacity which has not been utilized by active operations.
- Stock-based compensation was $6 million higher in the period-to-period comparison primarily due to additional non-cash expense and accelerated non-cash expense for retiree-eligible employees who received awards under the new CONSOL Share Unit (CSU) program, when compared to the prior year. The new program replaces several previously provided long-term executive compensation award programs. The compensation expense of the CSU program will not be materially different from the total expense of the previous programs over the three-year performance period.
- Bank Fees remained consistent in the period-to-period comparison.
- The short-term incentive compensation program is designed to increase compensation to eligible employees when CNX Gas reaches predetermined targets for safety, production and unit costs. Short-term incentive compensation expense decreased $6 million due to lower projected payouts in the 2013 period.
- PA impact fees are related to legislation in the state of Pennsylvania (Act 13 of 2012, House Bill 1950) which was signed into law during the first quarter of 2012. This legislation permits Pennsylvania counties to impose annual fees on unconventional gas wells located within their borders. As part of the legislation, all unconventional wells which were drilled prior to January 1, 2012 were assessed an initial fee related to periods prior to 2012. The $4 million represents this one-time initial assessment on wells drilled prior to January 1, 2012. Ongoing PA impact fees, which relate to wells drilled in the applicable period, are included as part of ad valorem, severance and other taxes in the Marcellus gas segment.
- Other corporate related expense remained consistent in the period-to-period comparison.

Interest expense related to the gas segment was $9 million for the year ended December 31, 2013 compared to $5 million for the year ended December 31, 2012. Interest was incurred by the gas segment on the CNX Gas revolving credit facility and a capital lease. The $4 million increase was primarily due to higher levels of borrowings on the revolving credit facility throughout the period-to-period comparison.

TOTAL COAL SEGMENT ANALYSIS - CONTINUING OPERATIONS for the year ended December 31, 2013 compared to the year ended December 31, 2012:

The coal segment contributed $337 million of earnings before income tax from continuing operations in the year ended December 31, 2013 compared to $592 million in the year ended December 31, 2012.

	For the Year Ended December 31, 2013					Increase (Decrease) from Year Ended December 31, 2012				
	Thermal Coal	High Vol Met Coal	Low Vol Met Coal	Other Coal	Total Coal	Thermal Coal	High Vol Met Coal	Low Vol Met Coal	Other Coal	Total Coal
Sales:										
Produced Coal	$1,388	$160	$447	$—	$1,995	$(43)	$(50)	$(59)	$(5)	$(157)
Purchased Coal	—	—	—	23	23	—	—	—	6	6
Total Outside Sales	1,388	160	447	23	2,018	(43)	(50)	(59)	1	(151)
Freight Revenue	—	—	—	35	35	—	—	—	(72)	(72)
Other Income	2	2	—	98	102	—	(4)	—	(226)	(230)
Total Revenue and Other Income	1,390	162	447	156	2,155	(43)	(54)	(59)	(297)	(453)
Costs and Expenses:										
Beginning inventory costs	33	—	21	—	54	(34)	(2)	5	—	(31)
Total direct costs	626	79	196	101	1,002	33	(16)	12	(44)	(15)
Total royalty/production taxes	68	5	26	2	101	(6)	(4)	(4)	(1)	(15)
Total direct services to operations	134	15	27	163	339	(20)	(6)	5	(54)	(75)
Total retirement and disability	58	7	25	10	100	(3)	(3)	(3)	(10)	(19)
Depreciation, depletion and amortization	116	15	41	46	218	(4)	(7)	4	13	6
Ending inventory costs	(21)	—	(10)	—	(31)	12	—	11	—	23
Total Costs and Expenses	1,014	121	326	322	1,783	(22)	(38)	30	(96)	(126)
Freight Expense	—	—	—	35	35	—	—	—	(72)	(72)
Total Costs of Goods Sold	1,014	121	326	357	1,818	(22)	(38)	30	(168)	(198)
Earnings (Loss) Before Income Taxes	$376	$41	$121	$(201)	$337	$(21)	$(16)	$(89)	$(129)	$(255)

THERMAL COAL SEGMENT

The thermal coal segment contributed $376 million to total Company earnings before income tax for the year ended December 31, 2013 compared to $397 million for the year ended December 31, 2012. The thermal coal revenue and cost components on a per unit basis for these periods are as follows:

	For the Years Ended December 31,			
	2013	2012	Variance	Percent Change
Company Produced Thermal Tons Sold (in millions)	21.5	20.7	0.8	3.9 %
Average Sales Price Per Thermal Ton Sold	$64.78	$69.08	$(4.30)	(6.2 %)
Beginning Inventory Costs Per Thermal Ton	$50.86	$61.92	$(11.06)	(17.9 %)
Total Direct Operating Costs Per Thermal Ton Produced	$29.55	$29.29	$0.26	0.9 %
Total Royalty/Production Taxes Per Thermal Ton Produced	3.22	3.65	(0.43)	(11.8 %)
Total Direct Services to Operations Per Thermal Ton Produced	6.31	7.61	(1.30)	(17.1 %)
Total Retirement and Disability Per Thermal Ton Produced	2.76	3.01	(0.25)	(8.3 %)
Total Depreciation, Depletion and Amortization Costs Per Thermal Ton Produced	5.45	5.93	(0.48)	(8.1 %)
Total Production Costs Per Thermal Ton Produced	$47.29	$49.49	$(2.20)	(4.4 %)
Ending Inventory Costs Per Thermal Ton	$(50.82)	$(50.89)	$0.07	0.1 %
Total Costs of Goods Sold Per Thermal Ton Sold	$47.33	$50.00	$(2.67)	(5.3 %)
Average Margin Per Thermal Ton Sold	$17.45	$19.08	$(1.63)	(8.5 %)

Thermal coal revenue was $1,388 million for the year ended December 31, 2013 compared to $1,431 million for the year ended December 31, 2012. The $43 million decrease was attributable to a $4.30 per ton lower average sales price offset, in part, by a 0.8 million increase in tons sold. The lower average thermal coal sales price in the 2013 period was the result of the renewal of several domestic thermal contracts whose pricing was reduced effective January 1, 2013. The decrease in price was partially offset by 2.0 million tons of thermal coal being priced on the export market at an average sales price of $63.04 per ton for the year ended December 31, 2013 compared to 2.1 million tons at an average price of $61.28 per ton for the year ended December 31, 2012.

Other income attributable to the thermal coal segment represents earnings from our equity affiliates that operate thermal coal mines. The equity in earnings of affiliates is insignificant to the total segment activity.

Total cost of goods sold is comprised of changes in thermal coal inventory, both volumes and carrying values, and costs of tons produced in the period. Total cost of goods sold for thermal coal was $1,014 million for the year ended December 31, 2013, or $22 million lower than the $1,036 million for the year ended December 31, 2012. Total cost of goods sold for thermal coal was $47.33 per ton in the year ended December 31, 2013 compared to $50.00 per ton in the year ended December 31, 2012. The decrease in total dollars and unit costs per thermal ton was due to the items described below.

Direct operating costs are comprised of labor, supplies, maintenance, power and preparation plant charges related to the extraction and sale of coal. These costs are reviewed regularly by management and are considered to be the direct responsibility of mine management. Direct operating costs related to the thermal coal segment were $626 million in the year ended December 31, 2013 compared to $593 million in the year ended December 31, 2012. Direct operating costs were $29.55 per ton produced in the current period compared to $29.29 per ton produced in the prior period. Changes in the average direct operating costs per thermal ton produced were primarily related to the following items:

- In 2013, CONSOL Energy entered into a new longwall lease at Bailey Mine which resulted in higher cost per ton produced in the period-to-period comparison.
-

Project expense increased in the 2013 period due to a longwall overhaul and a waterline extension project at Bailey Mine.

- Power expense increased in the 2013 period due to an increase in rates in the current year.

- Average cost of goods sold decreased due to an increase in tons sold. Fixed costs are allocated over more sales tons, resulting in lower unit costs.
- On July 27, 2012, a structural failure occurred at the Bailey Preparation Plant in Southwestern Pennsylvania. The belt system conveys coal from both the Bailey and Enlow Fork Mines to the Bailey Preparation Plant. The incident caused a total of four longwalls to be idled for approximately three weeks, and production to be at approximately 60% for the third quarter of 2012. The mines operated at full capacity for the entire 2013 period, which resulted in lower direct operating costs per ton produced.
- The Fola Mining Complex was idled in August 2012 which resulted in lower direct operating costs per ton produced in the period-to-period comparison. The mine, which was idled for market reasons, was a higher cost mining operation which when removed reduced the overall average direct operating costs per ton produced.

Royalties and production taxes were $68 million for the year ended December 31, 2013 compared to $74 million for the year ended December 31, 2012. The $6 million decrease in total dollars was primarily due to the the lower average sales prices which is the basis for most production taxes. The unit costs per thermal ton produced decreased $0.43 per ton to $3.22 per ton produced, due to the increase in production volumes.

Direct services to the operations are comprised of items which support groups manage on behalf of the coal operations. Costs included in direct services are comprised of subsidence costs, direct administrative and selling costs, permitting and compliance costs, mine closing and reclamation costs, and water treatment costs. The cost of these support services was $134 million in the current period compared to $154 million in the prior period. Direct services to the operations were $6.31 per ton produced in the current period compared to $7.61 per ton produced in the prior period. Changes in the average direct service to operations cost per thermal ton produced were primarily related to the following items:

- Average direct service costs to operations were improved due to a reduction in subsidence expense. The reduction was the result of the timing and nature of properties undermined in the period-to-period comparison.