CONSOL Energy Inc
Form 10-K
February 05, 2016

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, 2015

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. o

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, 2015, 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 $2,214,782,627.

The number of shares outstanding of the registrant's common stock as of January 20, 2016 is 229,054,236 shares.

DOCUMENTS INCORPORATED BY REFERENCE:

Portions of CONSOL Energy's Proxy Statement for the Annual Meeting of Shareholders to be held on May 11, 2016, are incorporated by reference in Items 10, 11, 12, 13 and 14 of Part III.

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## 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," "will," or their negatives, o similar 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 economic conditions in any of the industries in which our customers operate may decrease demand for our products, impair our ability to collect customer receivables and impair our ability to access capital;
- prices for natural gas, natural gas liquids and coal are volatile and can fluctuate widely based upon a number of factors beyond our control including oversupply relative to the demand available for our products, weather and the price and availability of alternative fuels;
- 

an extended decline in the prices we receive for our natural gas, natural gas liquids and coal affecting our operating results and cash flows;

- foreign currency fluctuations could adversely affect the competitiveness of our coal abroad;
- our customers extending existing contracts or entering into new long-term contracts for coal on favorable terms;
- our reliance on major customers;
- our inability to collect payments from customers if their creditworthiness declines or if they fail to honor their contracts;
- the disruption of rail, barge, gathering, processing and transportation facilities and other systems that deliver our natural gas, natural gas liquids 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 environmental regulations including any relating to greenhouse gas emissions on our operating costs as well as on the market for natural gas and coal and for our securities;
- the risks inherent in natural gas and coal operations, including our reliance upon third party contractors, 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 and transportation operations;
- 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 natural 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 our operations;
- 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 natural gas, oil and coal reserves;
- defects may exist in our chain of title and we may incur additional costs associated with perfecting title for natural gas rights on some of our properties or failing to acquire these additional rights may result in a reduction of our estimated reserves;
- the outcomes of various legal proceedings, including those which are more fully described in our reports filed under the Securities Exchange Act of 1934;
- 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;
- divestitures we anticipate may not occur or produce anticipated benefits;
- the terms of our existing joint ventures restrict our flexibility, actions taken by the other party in our natural 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 and oil reserves, which if not replaced, will cause our natural gas and oil reserves and production to decline;
- declines in our borrowing base could occur for a variety of reasons, including lower natural gas or oil prices, declines in natural gas and oil proved reserves, and lending regulations requirements or regulations;
- 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;
- information theft, data corruption, operational disruption and/or financial loss resulting from a terrorist attack or cyber incident;
- operating in a single geographic area;
- certain provisions in our multi-year sales contracts may provided limited protection during adverse economic conditions, and may result in economic penalties or permit the customer to terminate the contract;
- our common units in CNX Coal Resources LP and CONE Midstream Partners LP are subordinated, and we may not receive distributions from CNX Coal Resources LP or CONE Midstream Partners LP;

- other factors discussed in this 2015 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 Inc, (CONSOL Energy or the Company) 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 498% to produce 328.7 net Bcfe in 2015. 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. This growth was accelerated with the 2010 asset acquisition of the Appalachian Exploration & Production business of Dominion Resources, Inc. Subsequently, on December 5, 2013 we sold Consolidation Coal Company and certain subsidiaries, including five active coal mines in West Virginia.

Our E&P division operates, develops and explores for natural gas primarily in Appalachia (Pennsylvania, West Virginia, Ohio, Virginia and Tennessee). Currently, our primary focus is the continued development of our Marcellus Shale acreage and the delineation and development of our Utica Shale acreage. We believe that our concentrated operating area, our legacy surface acreage position, our regional operating expertise, our extensive data set from development, joint ventures, non-operated participation wells, 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 achieve production growth of approximately 15% in 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. The Noble Energy joint venture requires our partner to pay a portion of our qualifying drilling and completion costs in certain circumstances, which could improve drilling economics and enable the acceleration of development of these assets in the future.

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 436,000 net acres in the Marcellus Shale and approximately 622,000 net acres that have Utica Shale potential in Ohio, West Virginia, and Pennsylvania. In addition, we estimate that approximately 345,000 net acres of our Marcellus Shale acreage in Pennsylvania and West Virginia are prospective for the slightly shallower Upper Devonian Shale. We also have approximately 2.3 million net acres in our coalbed methane play.

Highlights of our 2015 production include the following:

- Total average production of 900,430 Mcfe per day, an increase of 39% over 2014;
- 87% Natural Gas, 13% Liquids; and
- 51% Marcellus, 23% coalbed methane, 17% Utica, and 9% other.

At December 31, 2015, our proved natural gas reserves had the following characteristics:

- 5.6 Tcfe of proved reserves;

- 89.7% natural gas;
- 65.5% proved developed;
- 66.3% operated; and
- A reserve life ratio of 17.17 years (based on 2015 production).

Highlights of coal activities in 2015 include the following:

- Underground mining complexes are among the safest in the United States of America;
- Production of 29.3 million tons of coal;
- Coal reserve holdings of 3.0 billion tons;
- 67% of coal sales to domestic utilities; and
- In July 2015, CNX Coal Resources LP (CNXC) closed its initial public offering.

Additionally, we provide energy services, including coal terminal services (the Baltimore Terminal), 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 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 approximately 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 for our natural gas.

CONSOL Energy's Strategy

CONSOL Energy's strategy is to increase shareholder value through the development and growth of its existing natural gas assets, selective acquisition of natural gas and natural gas liquid acreage leases within its footprint, and through the participation in global thermal and metallurgical coal markets. Ultimately, we intend to separate our E&P division and our Coal division and to focus on the growth of our E&P division. We also will continue to focus on monetization of assets to accelerate value creation and to minimize the shortfall between operating cash flows and our growth capital requirements.

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, the United States is expected to become a net exporter of natural gas in the next few years. Our increasing gas production, which we expect to grow by approximately 15% in 2016, will allow CONSOL Energy to participate in these markets. Production growth will come from three areas in 2016: new wells turned-in-line, non-operated production outside of the joint ventures with Hess and Noble Energy, and additional midstream debottlenecking projects.

CONSOL Energy’s coal assets align with the Coal division long-term strategic objectives. The production from the company’s Pennsylvania (PA) Operations, which include the Bailey, Enlow Fork, and Harvey mines, can be sold domestically or abroad, as either thermal coal or high volatile metallurgical coal. These low-cost mines, with five longwalls, produce a high-Btu Pittsburgh-seam coal that is lower in sulfur than many Northern Appalachian coals. Also, the company’s Buchanan Mine which is in our Virginia Operations produces a premium low volatile metallurgical coal for the steel industry. Our Other Coal operations primarily includes our Miller Creek Complex. The 2016 coal sales volumes guidance range is 27.0-32.0 million tons.

Our PA Operations has a 2016 sold position of 24.1 million tons. Although the timing of shipments creates quarter to quarter volatility, CONSOL Energy expects that the committed tons will get shipped in 2016. In addition, we continue to seek opportunities for additional incremental sales to offset any potential delays from contracted customers.

These mines, along with the 100%-owned Baltimore Terminal, will continue to allow CONSOL Energy to participate in the world’s thermal and metallurgical coal markets. The ability to serve both domestic and international markets with premium thermal and metallurgical coal provides tremendous optionality.

On December 31, 2014, in connection with our strategy to separate our E&P division from our Coal division, CONSOL Energy announced that its Board of Directors authorized management to pursue the formation of a master limited partnership (MLP) for the company’s thermal coal business, which would own interests in CONSOL Energy’s thermal coal properties and related mining operations located in Pennsylvania, including its Bailey Mine, Enlow Fork Mine, Harvey Mine and the related preparation plant. On July 7, 2015, CNX Coal Resources LP (CNXC) closed its initial public offering. Additionally, Greenlight Capital entered into a common unit purchase agreement with CNXC pursuant to which Greenlight Capital agreed to purchase, and CNXC agreed to sell, 5,000,000 common units at a price per unit equal to $15.00, which equates to $75 million in net proceeds. CNXC's general partner is CNX Coal Resources GP, a wholly owned subsidiary of CONSOL Energy. The underwriters of the IPO filing exercised an over-allotment option of 561,067 common units to the public at $15.00 per unit. The total net proceeds distributed to CONSOL Energy related to this transaction, along with CNXC entering into a new senior secured revolving credit facility, were $343 million.

CONSOL Energy's E&P Capital Expenditure Budget

In 2016, the E&P division expects capital expenditures between $205 and $325 million. The E&P division capital expenditures are comprised of the following: $110-$210 million for drilling and completion activity, which includes $10-$15 million for coalbed methane (CBM) activity; $40-$50 million for midstream, including approximately $22 million associated with expected CONE Midstream Partners, LP capital contributions; and $55-$65 million for other activities related to land, permitting, and business development.

The 2016 E&P capital reflects continued benefits from drilling and completion efficiencies and the deferral of mainly wet gas completions until market conditions improve economic viability. CONSOL Energy believes that it can partially offset this deferral of activity through potential production benefits related to additional gathering system debottlenecking projects in the second half of 2016. These additional debottlenecking projects are expected to provide upside benefits to 2017 natural gas sales volumes.

The lower end of the E&P capital expenditure range mainly reflects capital associated with completing approximately 37% of the company's inventory of drilled but uncompleted wells. The higher end of the range encompasses adding back a modest level of drilling activity, which could commence around mid-year. The extent of drilling activity in 2016, if any, will primarily be a function of rates of return, commodity prices, and the assessment of the dry Utica wells drilled in 2015. The Company expects to make a decision regarding drilling capital allocation before mid-year

2016.

DETAIL NATURAL 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, and Ohio from approximately 436,000 net Marcellus Shale acres at December 31, 2015.

CONSOL Energy and Noble Energy, our joint venture partner, drilled 79 gross wells in the Marcellus Shale in 2015. CONSOL Energy drilled 44 of those wells in the dry gas area of the formation. The geographic breakdown was as follows:

- 24 wells in Southwestern Pennsylvania,
- 13 wells in Central Pennsylvania,
- 7 wells in Northern West Virginia, and
- 35 wells drilled by Noble Energy in the wet gas area of the play.

CONSOL Energy completed 44 Marcellus Shale wells in 2015. The average completed lateral length was 7,019 feet with an average of 39 "frac" stages.

In 2016, the Company expects Marcellus Shale and Utica Shale completion activity to be the primary driver of gas production growth. In both the Noble Energy and Hess joint ventures, CONSOL Energy and its partners continue to work together to optimize their activity levels for 2016 in light of the rapidly changing commodity price environment.

We also hold a 50% interest in an entity that constructs and operates the gathering system for most of our Marcellus shale production. As of September 30, 2011, we contributed our existing Marcellus Shale gathering assets to this company. In September of 2014, the majority of these assets were contributed to CONE Midstream Partners LP.

CONSOL Energy and Noble Energy have dedicated approximately 516,000 net acres of their jointly owned Marcellus Shale acreage to this partnership for an initial term of 20 years and they have also granted a right of first offer on an additional approximately 186,000 net acres. This master limited partnership formed by us and Noble Energy will continue to build and operate most of our Marcellus Shale gathering systems. CONSOL Energy continues to serve as operator for CONE Midstream Partners LP. See "Midstream Gas Services" for a more detailed explanation.

Utica Shale

We control approximately 119,000 net acres of Utica Shale potential in eastern Ohio at December 31, 2015. Additionally, we control approximately 113,000 net acres in southwestern Pennsylvania and northern West Virginia that contain the rights to the natural gas in the Utica Shale. We estimate that approximately 391,000 net acres of our Marcellus Shale acreage in Pennsylvania and West Virginia are prospective for the Utica Shale. The thickness of the Utica Shale in these areas ranges from 200 to 450 feet.

In 2015, a total of 31 gross wells were drilled in the Utica Shale:

- CONSOL Energy and Hess, our joint venture partner, drilled 24 gross wells. CONSOL Energy drilled seven of those wells,
- CONSOL Energy and Noble Energy, drilled one gross well, and
- CONSOL Energy drilled an additional six gross wells in the deep dry Utica area that were not part of either Joint Venture.

Coalbed Methane (CBM)

We have the rights to extract CBM in Virginia from approximately 268,000 net CBM acres, which cover a portion of our coal reserves in Central Appalachia. We produce natural gas primarily from the Pocahontas #3 seam which is the main coal seam mined by our Buchanan Mine.

We also have the right to extract CBM in West Virginia, southwestern Pennsylvania, and Ohio from approximately 928,000 net CBM acres. In central Pennsylvania we have the right to extract CBM from approximately 260,000 net CBM acres. In addition, we control approximately 652,000 net CBM acres in Illinois, Kentucky, Indiana, and Tennessee. We also have the right to extract CBM on approximately139,000 net acres in the San Juan Basin and approximately 20,000 net acres in the Powder River Basin. We have no plans to drill CBM wells in these areas in 2016.

Other Gas

Shallow Oil and Gas

The shallow oil and gas acreage position of CONSOL Energy is approximately 825,000 net acres mainly in Illinois, Indiana, Kentucky, West Virginia, Pennsylvania, Virginia, and New York at December 31, 2015. 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.

Upper Devonian

The Upper Devonian Shale formation, which includes both the Burkett Shale and Rhinestreet Shale, 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.

In 2015, CONSOL Energy, with our joint venture partner Noble Energy, drilled eight wells in the Burkett Shale and one well in the Rhinestreet Shale. Our Marcellus Shale joint venture partner owns a 50% interest in the Burkett Shale formation within the joint venture area of mutual interest. We control a 100% interest in the Rhinestreet Shale formation that was acquired prior to the joint venture, with the exception of one well drilled in 2015 that Noble Energy opted into.

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 approximately 116,000 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 horizontal Chattanooga Shale wells.

Huron

We have approximately 380,000 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, 2015

| | Marcellus Segment | Utica Segment | CBM Segment | Other Gas Segment | Total |
|---|---|---|---|---|---|
| Estimated Net Proved Reserves (MMcfe) | 2,573,073 | 1,299,002 | 1,299,035 | 471,879 | 5,642,989 |
| Percent Developed | 72 % | 33 % | 74 % | 100 % | 65 % |
| Net Producing Wells (including oil and gob wells) | 236 | 46 | 4,385 | 8,196 | 12,863 |
| Net Acreage Position: | | | | | |
| Net Proved Developed Acres | 24,797 | 7,980 | 257,981 | 240,393 | 531,151 |
| Net Proved Undeveloped Acres | 6,666 | 11,281 | 6,000 | — | 23,947 |
| Net Unproved Acres(1) | 402,527 | 212,309 | 2,003,702 | 1,079,940 | 3,698,478 |
| Total Net Acres(2) | 433,990 | 231,570 | 2,267,683 | 1,320,333 | 4,253,576 |

(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, Utica, 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 are 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, 2015, the number of producing wells, developed acreage and undeveloped acreage:

| | Gross | Net(1) |
|---|---|---|
| Producing Gas Wells (including gob wells) | 17,349 | 12,834 |
| Producing Oil Wells | 188 | 29 |
| Net Acreage Position: | | |
| Proved Developed Acreage | 563,441 | 531,151 |
| Proved Undeveloped Acreage | 34,999 | 23,947 |
| Unproved Acreage | 4,672,920 | 3,698,478 |
| Total Acreage | 5,271,360 | 4,253,576 |

(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.

The following table represents the terms under which we hold these acres:

| | Net Unproved Acres | Net Proved Undeveloped Acres |
|---|---|---|
| Held by production/fee | 3,561,904 | 13,670 |
| Expiration within 2 years | 55,857 | 5,613 |
| Expiration beyond 2 years | 80,717 | 4,664 |
| Total Acreage | 3,698,478 | 23,947 |

The leases reflected above as Net Unproved Acres with expiration dates are included in our current drill plan or active land program. Leases with expiration dates within two years represent less than 2% of our total acres in the above categories and leases with expiration dates beyond two years represent less than 3% of our total acres in the above categories. In each case, we deemed this acreage to not be material to our overall acreage position. Additionally, based on our current drill plans and lease management we do not anticipate any material impact to our consolidated financial statements from the expiration of such leases.

Development Wells (Net)

During the years ended December 31, 2015, 2014 and 2013 we drilled 132.8, 180.3 and 139.8 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 2015, there were 189 gross development wells. There were no dry development wells in 2015, 2014, or 2013. As of December 31, 2015, there are 17.7 net development wells still in process. The following table illustrates the net wells drilled by well classification type:

| | For the Year Ended December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| Marcellus segment | 44.0 | 84.0 | 56.0 |
| Utica segment | 15.8 | 18.8 | 9.0 |
| CBM segment | 73.0 | 75.0 | 63.8 |
| Other Gas segment | — | 2.5 | 11.0 |
| Total Development Wells (Net) | 132.8 | 180.3 | 139.8 |

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Exploratory Wells (Net)

During the years ended December 31, 2015, 2014 and 2013, we drilled, in the aggregate, 2.5, 8.5, and 5.5 net exploratory wells, respectively. As of December 31, 2015, there are no net exploratory wells in process. The following table illustrates the exploratory wells drilled by well classification type:

| | For the Year Ended December 31, | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | 2015 | | | 2014 | | | 2013 | | |
| | Producing | Dry | Still Eval. | Producing | Dry | Still Eval. | Producing | Dry | Still Eval. |
| Marcellus segment | — | — | — | 0.5 | — | 1.0 | 2.5 | — | — |
| Utica segment | 1.5 | — | 1.0 | 1.0 | — | — | 3.0 | — | — |
| CBM segment | — | — | — | — | — | — | — | — | — |
| Other Gas segment | — | — | — | 6.0 | — | — | — | —— | — |
| Total Exploratory Wells (Net) | 1.5 | — | 1.0 | 7.5 | — | 1.0 | 5.5 | — | — |

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 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, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| Proved developed reserves | 3,697,152 | 3,198,706 | 2,514,294 |
| Proved undeveloped reserves | 1,945,837 | 3,628,910 | 3,216,920 |
| Total proved developed and undeveloped reserves(a) | 5,642,989 | 6,827,616 | 5,731,214 |

(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) | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| Future net cash flows | $2,503 | $9,321 | $6,568 |
| Total PV-10 measure of pre-tax discounted future net cash flows (1) | $1,659 | $4,884 | $2,780 |
| Total standardized measure of after tax discounted future net cash flows | $1,019 | $2,984 | $1,681 |

(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 Principles (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, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| | (Dollars in millions) | | |
| Future cash inflows | $11,838 | $28,503 | $21,603 |
| Future production costs | (6,585) | (10,101) | (7,106) |
| Future development costs (including abandonments) | (1,220) | (3,369) | (3,903) |
| Future net cash flows (pre-tax) | 4,033 | 15,033 | 10,594 |
| 10% discount factor | (2,374) | (10,149) | (7,814) |
| PV-10 (Non-GAAP measure) | 1,659 | 4,884 | 2,780 |
| Undiscounted income taxes | (1,534) | (5,712) | (4,026) |
| 10% discount factor | 894 | 3,812 | 2,927 |
| Discounted income taxes | (640) | (1,900) | (1,099) |
| Standardized GAAP measure | $1,019 | $2,984 | $1,681 |

Gas Production

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

| | For the Year Ended December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| GAS | | | |
| Marcellus Sales Volumes (MMcf) | 145,747 | 99,370 | 55,048 |
| Utica Sales Volumes (MMcf) | 38,344 | 10,303 | 531 |
| CBM Sales Volumes (MMcf) | 74,910 | 79,459 | 82,867 |
| Other Sales Volumes (MMcf) | 28,286 | 27,128 | 30,291 |
| LIQUIDS* | | | |
| NGLs Sales Volumes (MMcfe) | 33,180 | 15,475 | 2,628 |
| Oil Sales Volumes (MMcfe) | 593 | 681 | 634 |
| Condensate Sales Volumes (MMcfe) | 7,598 | 3,298 | 381 |
| TOTAL (MMcfe) | 328,658 | 235,714 | 172,380 |

*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 expects 2016 annual gas production to grow by approximately 15% when compared to 2015. Production growth will come from three areas in 2016: new wells turned-in-line, non-operated production outside of the joint ventures with Hess Corporation and Noble Energy, Inc., and additional midstream debottlenecking projects.

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 natural gas and liquids 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.

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| | For the Year Ended December 31, 2015 | 2014 | 2013 |
|---|---|---|---|
| Average Sales Price Before Effects of Financial Settlements (per Mcfe) | $2.13 | $4.26 | $3.85 |
| Gain on Commodity Derivative Instruments - Cash Settlement - Gas (per Mcf) | $0.68 | $0.11 | $0.45 |
| Average Sales Price (per Mcfe) | $2.81 | $4.37 | $4.30 |
| Average Lifting Costs excluding ad valorem and severance taxes (per Mcfe) | $0.30 | $0.46 | $0.56 |

Sales of NGLs, condensates, and oil enhance our reported natural gas equivalent sales price. Across all volumes, when excluding the impact of hedging, sales of liquids added $0.05 per Mcfe, $0.25 per Mcfe, and $0.14 per Mcfe for 2015, 2014, and 2013, respectively, to average gas sales prices. CONSOL Energy expects to continue to realize a liquids uplift benefit as additional wells are brought online in the liquid-rich areas of the Marcellus and Utica shales. We continue to sell the majority of our NGLs through the large midstream companies that process our natural gas. This approach allows us to take advantage of the processors' transportation efficiencies and diversified markets. CONSOL Energy's processing contracts provide for the ability to take our NGLs "in kind" and market them directly if desired. The processed purity products are ultimately sold to industrial, commercial, and petrochemical markets.

We enter into physical natural 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 natural gas swap transactions. These gas swap transactions exist parallel to the underlying physical transactions and represented approximately 173.1 Bcf of our produced gas sales volumes for the year ended December 31, 2015 at an average price of $3.68 per Mcf. These gas swaps represented approximately 159.9 Bcf of our produced gas sales volumes for the year ended December 31, 2014 at an average price of $4.58 per Mcf. As of January 13, 2016, we expect these transactions will represent approximately 223.6 Bcf of our estimated 2016 production at an average price of $3.26 per Mcf, 156.7 Bcf of our estimated 2017 production at an average price of $3.08 per Mcf, and approximately 75.8 Bcf of our estimated 2018 production at an average price of $3.07 per Mcf.

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 5,000 miles of natural 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 natural gas processing facilities. This infrastructure is capable of delivering approximately 750 billion cubic feet per year of pipeline quality gas.

CONSOL Energy 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 substantially all of Noble Energy's and CONSOL Energy's Marcellus Shale gathering systems. 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. On September 30, 2014, CONE Midstream Partners LP (the Partnership) closed its initial public offering of 20,125,000 common units representing limited partnership interests at a price to the public of $22.00 per unit, which included a 2,625,000 common unit over-allotment option that was exercised in full by the underwriters. The Partnership's general partner is CONE Midstream GP LLC, a wholly owned subsidiary of CONE Gathering LLC.

As a result of the IPO transaction, the Partnership received net proceeds of $412.7 million from the offering, after deducting underwriting discounts and commissions, and structuring fees of $28.8 million along with additional estimated offering expenses of approximately $1.2 million. Of the proceeds received, $204.0 million was distributed to each of CNX Gas Company LLC ("CNX Gas Company"), and Noble Energy on September 30, 2014.
In the Utica Shale, we and our joint venture partner, Hess, are primarily contracting with third-parties for gathering services.

CONSOL Energy has developed a diversified portfolio of firm transportation capacity options to support its production growth plan. CONSOL Energy plans to selectively acquire as needed firm capacity while minimizing transportation costs and long-term financial obligations and, in the near term if appropriate, plans to optimize and/or release firm transportation to others to enhance revenues. CONSOL Energy also benefits 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. In addition to firm transportation capacity, CONSOL Energy has developed a processing portfolio to support the projected volumes from its wet production areas and has operational and contractual flexibility to potentially convert a portion of currently processed wet gas volumes to be marketed as dry gas volumes.

CONSOL Energy has the advantage of having gas production from CBM, which can be lower Btu than pipeline specification, as well as higher Btu Marcellus Shale production. These two types of gas 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 offer an opportunity to blend ethane back into the gas stream when pricing or capacity for ethane markets dictate. In developing a diversified approach to managing ethane, CONSOL Energy has entered into ethane supply agreements and is discussing future outlet opportunities with ethane customers and midstream companies. These measures will allow us 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 a myriad of smaller producers, marketers, 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 U.S. producers of natural gas produced about 16% of dry natural gas production in the first six months of 2015. The EIA reported 513,386 producing natural gas wells in the United States at December 31, 2014, the latest year for which government statistics are available.

Natural gas increased market share in the U.S. electric generation market by about 5% compared to 2014 (based on preliminary 2015 results). We expect natural gas to be a 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 due to the expansion of exports to Mexico, waning imports from Canada, and completion of new liquefaction facilities with long-term export contracts including Cheniere’s Sabine Pass and Corpus Christi projects. 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, the availability and price of competing alternative fuel supplies, and national and regional supply/demand dynamics.

DETAIL COAL OPERATIONS

Coal Reserves

At December 31, 2015, CONSOL Energy had an estimated 3.0 billion tons of proven and probable coal reserves. 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 proved reserves have the highest degree of geologic assurance. Estimates for proved 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 proved reserves and between 3,000 and 8,000 feet for probable reserves.

CONSOL Energy's estimates of proven and probable coal 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 proved or probable reserves.

Our estimate of proven and probable coal reserves has been determined by CONSOL Energy’s geologists and mining engineers. CONSOL Energy's geologists and mining engineers completed an extensive re-evaluation of the longwall mineable Pittsburgh and Illinois No. 5 seams during 2014. The re-evaluations included the use of mine specific assumptions and mine plans versus general mine recovery factors and general parameters. To date, approximately 50% of CONSOL Energy’s reserves have been re-evaluated using mine specific parameters as opposed to an assumed average mining recovery factors. The 2014 re-evaluations resulted in 460 million of the total 471 million additional tons of proven and probable coal reserves added as result of revisions and other changes in 2014 (See Supplemental Coal Data in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K).

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 coal 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 coal 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 coal 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.

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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, 2015 and 2014

| Mine/Reserve | Preparation Facility 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 12/31/2015 | 12/31/201 |
|---|---|---|---|---|---|---|---|---|---|---|
| ASSIGNED–OPERATING | | | | | | | | | | |
| PA Operations | | | | | | | | | | |
| Bailey | Enon, PA | Assigned Operating | Pittsburgh | 7.6 | 12,950 | 12,800 – 13,040 | 44% | 56% | 101.1 | 84.0 |
| | | Accessible | Pittsburgh | 7.5 | 12,910 | 12,700 – 13,170 | 78% | 22% | 170.7 | 170.5 |
| Harvey | Enon, PA | Assigned Operating | Pittsburgh | 6.4 | 13,040 | 12,940 – 13,210 | 88% | 12% | 23.4 | 27.1 |
| | | Accessible | Pittsburgh | 7.6 | 12,910 | 12,850 – 13,140 | 99% | 1% | 180.1 | 181.2 |
| Enlow Fork | Enon, PA | Assigned Operating | Pittsburgh | 7.8 | 12,950 | 12,830 – 13,200 | 99% | 1% | 10.9 | 21.6 |
| | | Accessible | Pittsburgh | 7.6 | 13,010 | 12,750 – 13,150 | 76% | 24% | 305.3 | 301.2 |
| VA Operations | | | | | | | | | | |
| Buchanan | Mavisdale, VA | Assigned Operating | Pocahontas 3 | 6.0 | 13,810 | 13,710 – 14,040 | 20% | 80% | 40.4 | 44.8 |
| | | Accessible | Pocahontas 3 | 5.9 | 13,780 | 13,710 – 13,920 | 15% | 85% | 47.3 | 47.3 |
| Amonate Complex | Amonate, VA | Assigned Operating | Multiple | 4.3 | 13,150 | 12,850 – 13,350 | 69% | 31% | 15.8 | 15.8 |
| | | Accessible | Multiple | 6.4 | 12,880 | 12,880 – 12,880 | 100% | —% | 3.9 | 3.9 |
| Other Operations | | | | | | | | | | |
| Amvest Fola Complex | Bickmore, WV | Assigned Operating | Multiple | 4.6 | 12,380 | 12,250 – 12,550 | 86% | 14% | 73.4 | 73.4 |
| Miller Creek Complex | Delbarton, WV | Assigned Operating | Multiple | 2.6 | 12,050 | 11,600 – 12,650 | 38% | 62% | 49.9 | 52.0 |
| | | Accessible | Multiple | 5.1 | 12,590 | 12,590 – 12,590 | —% | 100% | 0.7 | 0.8 |
| Total Assigned Operating and Accessible | | | | | | | | | 1,022.9 | 1,023.6 |

(1) The heat values shown for Assigned Operating reserves are based on the 2015 actual quality and five-year forecasted quality for each mine/reserve, assuming that the coal is washed to an extent consistent with normal full-capacity operation of each mine's/complex's preparation plant. Actual quality is based on laboratory analysis of samples collected from coal shipments delivered in 2015. Forecasted quality is derived from exploration sample analysis results, which have been adjusted to account for anticipated moisture and for the effects of mining and coal preparation. The heat values shown for Accessible Reserves are based on as received, dry values obtained from drill hole analyses, adjusted for moisture, and prorated by the associated Assigned Operating product 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 an 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 reported only for those coal seams that are controlled by ownership or leases.

The following table sets forth our unassigned proven and probable coal reserves by region:
CONSOL Energy UNASSIGNED Recoverable Coal Reserves as of December 31, 2015 and 2014

| | | Recoverable Reserves(2) | | | Recoverable Reserves (Tons in Millions) |
|---|---|---|---|---|---|
| Coal Producing Region | As Received Heat Value(1) (Btu/lb) | Owned (%) | Leased (%) | Tons in Millions 12/31/2015 | 12/31/2014 |
| Northern Appalachia (Pennsylvania, Ohio, Northern West Virginia) (3) | 11,400 – 13,500 | 87% | 13% | 1,216.7 | 1,219.1 |
| Central Appalachia (Virginia, Southern West Virginia) | 11,400 – 14,200 | 51% | 49% | 322.2 | 321.2 |
| Illinois Basin (Illinois, Western Kentucky, Indiana) | 11,600 – 12,000 | 75% | 25% | 396.1 | 555.6 |
| Total | | 78% | 22% | 1,935.0 | 2,095.9 |

(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 are 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 reported only for those coal seams that are controlled by ownership or leases.

(3) 140.8 Million tons of the Northern Appalachia leased tons are controlled by Consolidation Coal Company, a former subsidiary of CONSOL Energy that was sold in December 2013. As of filing these tons are still controlled by Consolidation Coal Company but are shown in CONSOL Energy's reserves due to a binding agreement that these tons will be released to CONSOL Energy following the change in name of the Lease Holder.

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, 2015

| | ≤ 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 | — | — | 248.7 | — | — | — | 254.9 | 8.4 % |
| Med Vol Bituminous | — | 5.1 | 57.1 | — | — | 2.9 | — | — | — | 65.1 | 2.1 % |
| Low Vol Bituminous | — | — | 122.4 | — | — | 73.7 | — | — | — | 196.1 | 6.4 % |
| Total Metallurgical | — | 5.1 | 185.7 | — | — | 325.3 | — | — | — | 516.1 | 16.9 % |
| Thermal(1): | | | | | | | | | | | |
| High Vol A Bituminous | 29.2 | 80.4 | 4.5 | 38.2 | 105.2 | 32.8 | 53.8 | 1,171.1 | 614.7 | 2,129.9 | 69.9 % |
| High Vol B Bituminous | — | — | — | — | 101.2 | — | — | 186.7 | — | 287.9 | 9.5 % |
| High Vol C Bituminous | — | — | — | — | — | — | 108.4 | — | — | 108.4 | 3.6 % |
| Low Vol Bituminous | — | — | — | — | — | — | — | — | 4.5 | 4.5 | 0.1 % |
| Total Thermal | 29.2 | 80.4 | 4.5 | 38.2 | 206.4 | 32.8 | 162.2 | 1,357.8 | 619.2 | 2,530.7 | 83.1 % |
| Total | 29.2 | 85.5 | 190.2 | 38.2 | 206.4 | 358.1 | 162.2 | 1,357.8 | 619.2 | 3,046.8 | 100.0 % |
| Percent of Total | 1.0 % | 2.8 % | 6.2 % | 1.3 % | 6.8 % | 11.7 % | 5.3 % | 44.6 % | 20.3 % | 100.0 % | |

(1) 143.3 Million tons for the Mason Dixon Project are controlled by Consolidation Coal Company, a former subsidiary of CONSOL Energy that was sold in December 2013. As of this filing, these tons are still controlled by Consolidation Coal Company but are shown in CONSOL Energy's reserves due to a binding agreement that these tons will be released to CONSOL Energy upon consent of the lessor.

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, 2015, 2014 and 2013.

| Year | Total Royalty Tonnage (in thousands) | Total Coal Acreage Leased | Total Royalty Income (in thousands) |
|---|---|---|---|
| 2015 | 7,459 | 235,066 | $14,914 |
| 2014 | 10,230 | 281,894 | $18,460 |
| 2013 | 8,335 | 271,755 | $16,906 |

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, 2015, 93% of CONSOL Energy's production came from underground mines and 7% from surface mines. CONSOL Energy employs longwall mining systems in our underground mines where the geology is favorable and reserves are sufficient. For the year ended December 31, 2015, 93% 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, in millions of tons, for CONSOL Energy's mines for the years ended December 31, 2015, 2014 and 2013, 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.

| Mine | Preparation Facility Location | Mine Type | Mining Equipment | Transportation | Tons Produced (in millions) 2015 | 2014 | 2013 | Year Established or Acquired |
|---|---|---|---|---|---|---|---|---|
| PA Operations | | | | | | | | |
| Bailey | Enon, PA | U | LW/CM | R R/B | 10.2 | 12.3 | 10.8 | 1984 |
| Enlow Fork | Enon, PA | U | LW/CM | R R/B | 9.0 | 10.6 | 10.1 | 1990 |
| Harvey (4) | Enon, PA | U | LW/CM | R R/B | 3.6 | 3.2 | 0.6 | 2014 |
| VA Operations | | | | | | | | |
| Buchanan (1) | Mavisdale, VA | U | LW/CM | R T | 4.4 | 4.0 | 4.8 | 1983 |
| Other | | | | | | | | |
| Miller Creek Complex (2) | Delbarton, WV | U/S | CM/S/L | R T | 2.1 | 2.1 | 2.2 | 2004 |
| Total | | | | | 29.3 | 32.2 | 28.5 | |
| | | | | | | | | |
| CONSOL Energy Portion of Equity Affiliates | | | | | | | | |
| Harrison Resources (2)(3) | Cadiz, OH | S | S/L | R T | — | 0.3 | 0.4 | 2007 |
| Western Allegheny (2)(3) | Young Township, PA | U | CM | R T | 0.4 | 0.5 | 0.3 | 2010 |
| Total CONSOL Energy Portion of Equity Affiliates | | | | | 0.4 | 0.8 | 0.7 | |

S – Surface
U – Underground
LW – Longwall
CM – Continuous Miner
S/L – Stripping Shovel and Front End Loaders
R – Rail
R/B – Rail to Barge
T – Truck
(1) – Mine was idled for part of the year(s) presented due to market conditions.
(2) – Harrison Resources, Miller Creek Complex, Amonate Complex and Western Allegheny (includes facilities operated by independent contractors).
(3) – Production amounts represent CONSOL Energy's 49% ownership interest. Interest in Harrison Resources was sold in October 2014. Interest in Western Allegheny was sold in September 2015.
(4) – Completed development work and was placed in service in March 2014.

Coal Capital

In 2016, CONSOL Energy expects to invest $170-$190 million in the Coal and Other division: $140-$155 million allocated to production and $30-$35 million for other activities related to land, water, safety, and the Baltimore Terminal.

Coal Marketing and Sales

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

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| Average Sales Price Per Ton Sold– PA Operations | $56.36 | $61.88 | $63.93 |
| Average Sales Price Per Ton Sold– VA Operations | $56.70 | $71.80 | $92.43 |
| Average Sales Price Per Ton Sold– Other Operations | $60.01 | $60.12 | $70.22 |
| Average Sales Price Per Ton Sold– Total Company | $56.66 | $63.03 | $69.34 |

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 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 follow:

| | Tons Sold (in millions) | Percent of Total | |
|---|---|---|---|
| PA Operations | 22.9 | 78 | % |
| VA Operations | 4.4 | 15 | % |
| Other Operations | 1.9 | 7 | % |
| Total tons sold | 29.2 | 100 | % |

Approximately 67% of our 2015 coal sales were made to U. S. electric generators, 26% of our 2015 coal sales were priced on export markets and 7% of our coal sales were made to other domestic customers. We had sales to over 40 customers from our 2015 coal operations. During 2015, Xcoal Energy Resources and Duke Energy each comprised over 10% of our revenues, and the top four coal customers accounted for more than 36% of our total revenues.

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. 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, 2015, over 66% of all the coal we produced was sold under contracts with terms of one year or more.

The following table sets forth CONSOL Energy's estimated production and sales:
COAL DIVISION GUIDANCE
(Tons in millions)

| | 2016 | 2017 |
|---|---|---|
| Est. Total Coal Sales | 27.0 - 32.0 | 30.5 - 33.4 |
| Committed | 27.8 | 12.7 |
| Estimated Price (committed tons) | $50-$55 | $50-$55 |
| Est. PA Operations Sales | 22.0 - 26.0 | 25.0 - 27.0 |
| Committed | 24.1 | 11.1 |
| Est. VA Operations Sales | 3.5 - 4.2 | 3.7 - 4.2 |
| Committed | 1.9 | 1.6 |
| Est. Other Sales | 1.5 - 1.8 | 1.8 - 2.2 |
| Committed | 1.8 | — |

Note: Committed tons are tons that are both committed to be purchased and priced. Committed tons exclude collared tons and tons that are sold but not yet priced. There are no collared tons in 2015 or 2016. Collared tons in 2017 are 4.9 million tons, with a ceiling of $50.98 per ton and a floor of $43.77 per ton. Contracts with certain customers permit the customer to carry a portion of their contracted tons into the following year and/or to take gas instead of coal. For purposes of this table, the estimated price of each committed contract includes the base price stated in the contract and an estimate of the future adjustments to the contracted base price as set forth in such contract. The adjustment mechanisms reflect (i) variances in the quality characteristics of coal delivered to the customer beyond threshold quality characteristics specified in the applicable sales contract, (ii) the actual calorific value of coal delivered to the customer, and/or (iii) changes in electric power prices in the markets in which our customers operate, as adjusted for any factors set forth in the applicable contract. Each customer contract is different and not all contracts contain adjustments described in the preceding sentence. The estimated prices set forth in the table above were based in part on certain assumptions made by management. With respect to clause (i) quality characteristics, we based our assumption on our average monthly estimated quality numbers generated with our production forecast, created using pre-mining geology and analytical work, to determine the likely penalties and premiums associated with each contract using the average mine quality for tons estimated to be shipped during the time period. With respect to clause (ii) actual calorific value, we based our assumption on our average monthly estimated quality numbers generated with our production forecast, created using premining geology and analytical work, to determine the likely penalties and premiums associated with each contract using the average mine quality for tons estimated to be shipped during the time period. With respect to clause (iii), the electric power price-related adjustments, if any, result only in positive monthly adjustments to the contracted base price that we receive for our coal. These adjustments to contracted base prices were estimated using publicly available regional power generation information applicable to the markets in which our customers operate and other internally estimated information regarding contract specific factors that impact pricing. The key assumptions used for the estimated electric power price-related adjustments were derived using PJM Western Hub Day-Ahead Calendar Month (Peak and Off-Peak) prices adjusted using management's judgment and historical results. These derived assumptions were held constant in 2016 and 2017. While management considers the expectations and assumptions regarding estimated prices, including with respect to estimated electric power price-related adjustments, to be reasonable, they are inherently subject to business, economic, competitive, regulatory, and other risks and uncertainties, most of which are beyond our control.

Coal pricing for contracts with terms of one year or less are 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

Both the domestic and international coal industries are 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 disasters/weather; 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, coal 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.

Terminal Services

In 2015, approximately 8.1 million tons of coal were shipped through CONSOL Energy's subsidiary, CNX Marine Terminals Inc.'s, exporting terminal in the Port of Baltimore. Approximately 67% 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 Division

CNX Water Assets LLC, is doing business as CONVEY Water Systems LLC, is a wholly-owned subsidiary of CONSOL Energy and supplies turnkey solutions for water sourcing, delivery and disposal for our E&P operations, supplies solutions for water sourcing, delivery and disposal for third parties and also provides supplemental water sourcing and marketing efforts on behalf of CNXC. In coordination with our midstream operations, CONVEY Water Systems works to develop solutions that coincide with our midstream operations to offer gas gathering and water delivery solutions in one package to third parties.

Employee and Labor Relations

At December 31, 2015, CONSOL Energy had 3,114 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, 2015, 2014 and 2013 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 natural gas and coal mining operations are subject to various types of federal, state and local laws and 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 natural gas or coal 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 is committed to complying with all laws and regulations. This commitment is evident in CONSOL Energy's demonstrated cost and effort to abate and control pollution and/or contamination at its facilities. CONSOL Energy made capital expenditures for environmental control facilities of approximately $18.4 million, $19.0 million, and $1.6 million in the years ended December 31, 2015, 2014 and 2013, respectively. CONSOL Energy does not expect to have any capital expenditures in 2016 for environmental control facilities.

Environmental Laws

Clean Air Act and Related Regulations. The federal Clean Air Act (CAA) and corresponding state laws and regulations regulate air emissions primarily through permitting and/or emissions control requirements. This affects natural gas production and processing operations as well as coal mining, coal handling, and processing.

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 ($SO_2$) from various oil and gas exploration, production, processing and transportation facilities. Additionally, revisions were made 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. Section 111 of the CAA authorized the EPA to develop technology based standards which apply to specific categories of stationary sources. On September 18, 2015, the EPA proposed updates to the New Source Performance Standards (NSPS) that would create new standards for the regulation of methane and VOC emission sources. The proposed rule includes requirements for new fugitive emission and leak detection testing and reporting requirements. Also on September 18, 2015, the EPA proposed the Source Determination Rule which would clarify the use of the term “adjacent” in determining Title V air permitting requirements as they apply to the oil and natural gas industry for major sources of air emissions.

The EPA has proposed to amend the Petroleum and Natural Gas Systems source category (Subpart W) of the Greenhouse Gas Reporting Program (GHGRP). Currently, we are required to annually report greenhouse gas emission from natural gas wells, coal mines and associated facilities. This proposed rule would add reporting of greenhouse gas emissions from certain gathering and boosting systems, completions and workovers of oil wells using hydraulic fracturing, and blowdowns of natural gas transmission pipelines. The rule would also require operators to utilize new monitoring equipment in order to comply with Subpart W.

The CAA also indirectly and more significantly affects the U.S. coal industry by extensively regulating the air emissions of 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 increase the costs to operate and could affect demand for coal as a fuel source and affect the volume of our sales. Moreover, additional environmental regulations increase the likelihood that existing coal-fired electric generating plants will be decommissioned, including plants to which CONSOL Energy sells coal to, and reduce the likelihood that new coal-fired plants will be built in the future.

In early 2012, the EPA promulgated or finalized several rules for NSPS for coal- and oil- fired power plants which also have a negative effect on coal-generating facilities. The Utility Maximum Control Technology (UMACT) rule requires more stringent NSPS for particulate matter (PM), SO2 and NOX and the Mercury and Air Toxics Standards (MATS) rule requires new mercury and air toxic standards. In November 2012, the EPA published a notice of reconsideration of certain aspects of the UMACT and MATS rules. Following reconsideration in April 2013 and again in April 2014, the EPA promulgated final UMACT and MATS rules in November 2014 at which point the standards become applicable to new power plants. The final rules have higher emission limits, but the standards are still stringent and compliance with the rules is expensive.

On July 6, 2011, the EPA finalized a rule known as the Cross-State Air Pollution Rule (CSAPR). CSAPR regulates cross-border emissions of criteria air pollutants such as SO2 and NOX, as well as byproducts, fine particulate matter (PM2.5) and ozone by requiring states to limit emissions from sources that "contribute significantly" to noncompliance with air quality standards for the criteria air pollutants. If the ambient levels of criteria air pollutants are above the thresholds set by the EPA, a region is considered to be in "nonattainment" for that pollutant and the EPA applies more stringent control standards for sources of air emissions located in the region. In April 2014, the Supreme Court reversed a decision of the D.C. Circuit Court of Appeals that had vacated the rule. Following remand and briefing the D.C. Circuit Court, in October 2014, granted a motion to lift a stay of the rule and allow the EPA to modify the CSAPR compliance deadline by three-years, setting the stage for issuance of the proposed rule. Implementation of CSAPR Phase 1 began in 2015, with Phase 2 scheduled to begin in 2017. On December 3, 2015, the EPA proposed an update to the CSAPR for the 2008 Ozone National Ambient Air Quality Standards (NAAQS) by issuing the proposed CSAPR Update Rule. The rule will require reductions of seasonal nitrogen oxide emissions from power plants in 23 of the originally proposed 28 Eastern states to address interstate air quality impacts for the 2008 ozone air quality requirements in downwind states.

In April 2012, the EPA published its proposed NSPS for carbon dioxide (CO2) 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 CO2 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, the EPA re-proposed NSPS for CO2 for new fossil fuel fired power plants and rescinded the rules that were proposed on April 12, 2012.

On September 20, 2013, the EPA issued a new proposal to control carbon emissions from new power plants. Under the proposal, the EPA would establish separate NSPS for CO2 emissions for natural gas-fired turbines and coal-fired units. The proposed “Carbon Pollution Standard for New Power Plants” replaces an earlier proposal released by the EPA in 2012. On August 3, 2015, EPA finalized the Carbon Pollution Standards to cut carbon emissions from new, modified and reconstructed power plants, which became effective on October 23, 2015.

In another proposed rulemaking related to CO2 emissions, on June 2, 2014, the EPA proposed the Clean Power Plan to cut carbon emissions from existing power plants. Under this proposed rule, the EPA would create emission guidelines for states to follow in developing plans to address greenhouse gas emissions from existing fossil fuel-fired electric generating units. Specifically, the EPA is proposing state-specific rate-based goals for CO2 emissions from the power sector, as well as guidelines for states to follow in developing plans to achieve the state-specific goals. On August 3, 2015, the EPA finalized the Clean Power Plan Rule to cut carbon pollution from existing power plants, which became effective on December 22, 2015. States, industry, and labor organizations have filed at least 17 petitions for review in the D.C. Circuit of Appeals requesting that the Court stay implementation of the Clean Power Plan because they will suffer “irreparable harm.” Petitioners also argued that the Final Rule violates the CAA because energy generating units (EGUs) are already subject to hazardous air pollutant limits under Section 112 of the CAA.

The CAA requires the EPA to set NAAQS for certain pollutants and the CAA identifies two types of NAAQS. Primary standards provide public health protection, including protecting the health of "sensitive" populations such as asthmatics, children, and the elderly. Secondary standards provide public welfare protection, including protection against decreased visibility and damage to animals, crops, vegetation, and buildings. On October 1, 2015, the EPA finalized the NAAQS for ozone pollution and reduced the limit to 70 parts per billion (ppb) from the previous 75 ppb standard. The final rule could have a large impact on both the oil and gas and coal mining industries as states would be required to update their permitting standards to meet these potentially unachievable limits. Six states have now filed a petition for review in the D.C. Circuit of Appeals.

Clean Water Act. The federal Clean Water Act (CWA) and corresponding state laws affect our natural 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 CWA and corresponding state laws include requirements for: improvement of designated "impaired waters" (i.e., 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; requirements to minimize impacts and compensate for unavoidable impacts resulting from discharges of fill materials to regulated streams and wetlands; and 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 and require the implementation of plans to address any spills and the installation of secondary containment around all storage 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 natural gas from tight rock formations such as the Marcellus shale and Utica shale. The EPA initiated the study in early January 2011 and the final assessment report was published on June 4, 2015. The assessment showed hydraulic fracturing activities have not led to widespread, systemic impacts to drinking water resources.

CONSOL Energy utilizes pipelines extensively for its natural gas, water and coal businesses, and mitigation permits from the Army Corps of Engineers (ACOE) are typically required for certain impacts to streams and wetlands. On April 21, 2014 the EPA published a proposed rule called “Definition of ‘Waters of the United States’ (WoUS) Under the Clean Water Act.” The proposal would expand the scope of the CWA to include previously non-jurisdictional streams, wetlands, and waters, making these areas jurisdictional inter-coastal waters of the U.S. In February 2015 the EPA and ACOE issued a memorandum of understanding to withdraw the WoUS Interpretive Rule. The EPA published the latest version of the WoUS rule (the Clean Water Rule) on June 29, 2015, which was to become effective on August 28, 2015. However, on August 27, 2015, the District Court for the District of North Dakota blocked implementation of the rule in 13 states. On October 9, 2015, the U.S. Circuit Court of Appeals for the Sixth Circuit blocked implementation of the rule nationwide.

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 implemented several initiatives that have delayed and obstructed the issuance of surface mining operation permits 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 the EPA’s policies but the EPA continues with its initiatives. Thus far, CONSOL Energy’s subsidiaries have been able to continue operating their existing mines. There is no assurance that permits can be obtained for future mining operations.

Resource Conservation and Recovery Act. The federal Resource Conservation and Recovery Act (RCRA) and corresponding state laws and regulations affect natural 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 of are subject to corrective action orders issued by the EPA that could adversely affect our results, financial condition and cash flows. In 2010, the EPA proposed options for the regulation of Coal Combustion Residuals (CCRs) from the electric power sector as either hazardous waste or non-hazardous waste. On December 19, 2014, the EPA announced the first national regulations for the disposal of CCRs from electric utilities and independent power producers under RCRA. On April 17, 2015, the EPA finalized these regulations under the solid waste provisions (Subtitle D) of RCRA and not the hazardous waste provisions (Subtitle C) which became effective on October 19, 2015. The EPA affirms in the preamble to the final rule that "this rule does not apply to CCR placed in active or abandoned underground or surface mines." Instead, "the U.S. Department of Interior (DOI) and the EPA will address the management of CCR in mine fills in a separate regulatory action(s)." On November 3, 2015, the EPA published the final rule Effluent Limitations Guidelines and Standards (ELG), revising the regulations for the Steam Electric Power Generating category which became effective on January 4, 2016. The rule sets the first federal limits on the levels of toxic metals in wastewater that can be discharged from power plants, based on technology improvements in the steam electric power industry over the last three decades. The combined effect of the CCR and ELG regulations has forced power generating companies to close existing ash ponds and will likely force the closure of certain older existing coal burning power plants that can't comply with the new standards.

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 natural 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. On April 2, 2015, the U.S. Fish and Wildlife Service (USFWS) published the listing of the Northern Long-eared Bat (NLEB) as Threatened with 4(d) Rule status which became effective on May 4, 2015. Other species that are being considered by the FWS for listing and that are found in CONSOL Energy's operational area are the Big Sandy Crayfish, the Guyandotte River Crayfish and the Rusty Patched Bumble Bee, all of which have the potential to interfere with operational planning if listed.

Surface Mining Control and Reclamation Act. The federal Surface Mining Control and Reclamation Act (SMCRA) establishes minimum national operational 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 $0.28 per ton for surface mined coal and $0.12 per ton for underground mined coal. These fees are currently scheduled to be in effect until September 30, 2021.

Excess Spoil, Coal Mine Waste, Diversions, and Buffer Zones for Perennial and Intermittent Streams. The OSM has issued final amendments to regulations concerning stream buffer zones, stream channel diversions, excess spoil, and coal mine waste to comply with an order issued by the U.S. District Court for the District of Columbia on February 20, 2014, which vacated the stream buffer zone rule that was published December 12, 2008. On July 27, 2015, OSM published the proposed Stream Protection Rule. The proposed rule includes changes that amount to a rewrite of the existing rule on a nationwide scale and that adds and revises regulations for surface mines, underground mines and ancillary facilities located in every coal producing state. We believe this to be an overreach of jurisdiction by the OSM, particularly into areas under the legal jurisdiction of other federal agencies, particularly the EPA, the Corps of Engineers, and the U.S. Fish and Wildlife Service, as well as delegated state programs or state laws (e.g., Clean Water Act authority, PA Clean Streams Law, etc.). Additionally, OSM proposes to extend the impacts of mining to include surrounding areas of the entire reserve, previously not included in assessments submitted with our permits for active mining. The proposed rule would also prohibit mining in or through a perennial, intermittent, or ephemeral stream, even if the effects are temporary, and to require a 100' buffer zone on each side of a stream, which sterilizes the coal under those streams as unmineable. As drafted, this proposed rule has the potential to impact CONSOL Energy's ability to profitably operate longwall coal mines.

Federal Regulation of the Sale and Transportation of Natural 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 natural 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 has 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 purchase and installation of proximity detection services on continuous miner machines;
- 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;
- more stringent rock dusting requirements; and
- the purchase of personal dust monitors for collecting respirable dust samples from certain miners.

On October 2, 2015, the Mine Safety and Health Administration (MSHA) published proposed rules for underground coal mining operations concerning proximity detection systems for coal hauling machines and scoops. On January 15, 2015, MSHA published a final rule requiring underground coal mine operations to equip continuous mining machines, except full-face continuous mining machines, with proximity detection systems. The proximity detection system strengthens protection for miners by reducing the potential of pinning, crushing and striking hazards that result in accidents involving life-threatening injuries and death. The final rule became effective March 15, 2015 and included a phased in schedule for newly manufactured and in-service equipment. In 2010 MSHA rolled out the “End Black Lung, Act Now” initiative. As a result, MSHA implemented a new final rule on August 1, 2014 to lower miners’ exposure to respirable coal mine dust including using the new Personal Dust Monitor (PDM) technology. This final rule will be implemented in three phases. The first phase began on August 1, 2014 and utilizes the current gravimetric sampling device to take full shift dust samples from the current designated occupations and areas. It also requires additional record keeping and immediate corrective action in the event of overexposure. The second phase began on February 1, 2016 and requires additional sampling for designated and other occupations using the new continuous personal dust monitor (CPDM) technology, which provides real time dust exposure information to the miner. CONSOL Energy has ordered the necessary CPDM equipment which is required to meet compliance with the new rule at a cost of $2 million. We are also in the process of hiring Dust Coordinators and Dust Technicians to meet the staffing demand to manage compliance with the new rule at an estimated cost of $3 million. The final phase of the rule will take effect on August 1, 2016. The current respirable dust standard will then be reduced from 2.0 to 1.5mg/m3 for designated occupations and from 1.0 to 0.5mg/m3 for Part 90 Miners.

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 coal 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 coal 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. The changes have increased the cost to CONSOL Energy of complying with the Federal Black Lung Benefits Act. 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 Natural Gas Business

Regulation Affecting Gas Operations. Our natural 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 natural 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 natural 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 natural 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. Apart from SEC filings, we also use our website to publish information which may be important to investors, such as presentations to analysts.

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 “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 a material adverse effect on our liquidity, results of operations, 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. The general economic challenges for some of our customers continued in 2015 and the outlook is uncertain. In addition, liquidity is essential to our business and developing our assets. Renewed or continued weakness in the economic conditions of any of the industries we serve or are served by our customers could adversely affect our business, financial condition, results of operation and liquidity 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;
- 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
- a decline in our creditworthiness, which may require us to post letters of credit, cash collateral, or surety bonds to secure certain obligations, all of which would have an adverse effect on our liquidity.

Prices for natural gas, natural gas liquids and coal are volatile and can fluctuate widely based upon a number of factors beyond our control including oversupply relative to the demand available for our products, weather and the price and availability of alternative fuels. An extended decline in the prices we receive for our natural gas, natural gas liquids and coal will adversely affect our business, operating results, financial condition and cash flows.

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

Our E&P division’s products (natural gas, natural gas liquids, oil and condensate) accounted for approximately 29% of our outside sales revenues from continuing operations in 2015, with natural gas and natural gas liquids representing 95% of the division’s outside sales revenues. Natural gas, natural gas liquids and oil prices are very volatile and can fluctuate widely based upon supply from energy producers relative to demand for these products and other factors beyond our control. The sale to Murray Energy in 2013 of almost one half of our thermal coal production increased our exposure to fluctuations in the price of metallurgical coal, natural gas, natural gas liquids and oil.

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 these lower gas prices, to meet drilling commitments. Although gas prices recovered somewhat during 2013 and the first quarter of 2014, they again significantly declined in the latter part of 2014 due to oversupply and remained at depressed levels throughout 2015.

Our natural gas operations are geographically concentrated in the mid-Atlantic states. The success of the Marcellus Shale play and development of other Shale plays has resulted in growth in natural 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 and during 2014 and continuing into 2015, the spot prices at some Appalachian hubs fell below Henry Hub prices. 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. Oversupply from drilling in these plays, despite lower prices, directly affects prices we receive. Thus, apart from the general impact of domestic production on overall gas prices, the price paid for our natural gas also may continue to be adversely affected by increasing production and oversupply in our market. Low natural gas prices adversely impact our natural gas operating revenues and earnings before income taxes.

An extended period of lower natural gas prices can negatively affect us in several other ways. These include reduced cash flow, which decreases funds available for capital expenditures to replace reserves or increase production. For example, in light of the low natural gas prices continuing from 2014 into 2015, we substantially decreased our 2016 planned capital expenditures and the drilling of new shale wells. 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. For example, in the second quarter of 2015, we had an impairment charge of approximately $825 million for our natural gas assets, primarily shallow oil and gas 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 also volatile for reasons similar to those described above regarding natural gas. As a result of increasing supply, including from shale plays, oil prices fell to five year lows during 2014 and further declined during 2015. In addition, similar to the oversupply of natural gas, increased drilling activity by third parties in formations containing natural gas liquids has led to a decline of over 80 percent in the price of natural gas liquids. Our results of operation may be adversely affected by the continued depressed level of or further downward fluctuations in natural gas liquids and oil prices.

The coal industry also faces concerns with respect to oversupply of both metallurgical coal and thermal coal. China, a key participant in the seaborne market, has experienced a decrease in demand for coal imports while there has been an increase in supply, primarily from Australia. Coal accounted for approximately 61% of our outside sales revenues from continuing operations in 2015. In 2014, our average sales price per ton of coal fell by approximately 22% due to oversupply, which was particularly acute in the international market. This trend continued in 2015 with metallurgical coal prices falling to seven year lows and our average sales price of low volatile metallurgical coal further declined by another 21% from 2014’s depressed price.

Apart from issues with respect to the supply of products we produce, demand can fluctuate widely due to a number of matters beyond our control, including:

- changes in the consumption pattern of industrial consumers, electricity generators and residential users;
- weather conditions in our markets which affect the demand for natural gas and thermal coal (for example, the unusually warm 2011 - 2012 winter left utilities with large coal stockpiles and depressed the demand for thermal coal);
- proximity and capacity of gas pipelines and other transportation facilities;
- with respect to thermal coal, the price and availability of natural gas and the price and supply of imported liquefied natural gas;
- with respect to natural gas, the price and availability of thermal coal;
- technological advances affecting energy consumption;
- the costs, availability and capacity of transportation infrastructure;
- proximity and capacity of natural gas pipelines and other transportation facilities;

- the impact of domestic and foreign governmental laws and regulations, including environmental and climate change regulations and regulations affecting the coal mining industry and coal-fired power plants, and delays in the receipt of, failure to receive, failure to maintain or revocation of necessary governmental permits; and
- increased utilization by the steel industry of electric arc furnaces or pulverized coal injection processes to make steel which reduce or eliminate the use of furnace coke, an intermediate product produced from metallurgical coal,and decreases the demand for metallurgical coal.

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 and, as a result, general economic conditions in foreign markets and changes in foreign currency exchange rates may provide our foreign competitors with a competitive advantage. 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. If our competitors' currencies decline against the U.S. dollar or against our foreign customers' local currencies, those competitors may be able to continue to offer lower prices for coal to our customers. Furthermore, if the currencies of our overseas customers were to significantly decline in value in comparison to the U.S. dollar, those customers may seek decreased prices for the coal we sell to them. We also expect in the future that an international market will develop for exporting domestic natural gas and natural gas liquids. Consequently, currency fluctuations could adversely affect the competitiveness of our products in international markets, which could have a material adverse effect on our business, financial condition, results of operations, and cash flows.

If our coal customers do not extend existing contracts or do not enter into new multi-year coal sales contracts on favorable terms, profitability of CONSOL Energy's operations could be adversely affected.

During the year ended December 31, 2015, approximately 66% of the coal CONSOL Energy produced from continued operations was sold under multi-year sales contracts. If a substantial portion of our multi-year sales contracts are modified or terminated, if force majeure is exercised, or if we are unable to replace or extend the contracts or new contracts are priced at lower levels, our profitability would be adversely affected. The profitability of our multi-year sales 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, during 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, we 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, which may reduce our profitability.

The loss of, or significant reduction in, purchases by our largest coal customers or the failure of any of our customers to buy and pay for coal they committed to purchase could adversely affect our business, financial condition, results of operation and cash flows.

For the year ended December 31, 2015, we derived over 25% of our total revenues from sales to two coal customers individually and almost 36% of our total revenue from sales to our four largest coal and natural gas customers. At December 31, 2015, we had approximately 8 coal supply agreements with these customers that expire at various times from 2016 to 2019. There are inherent risks whenever a significant percentage of total revenues are concentrated with a limited number of customers. Revenues from our largest customers may fluctuate from time to time based on numerous factors, including market conditions, which may be outside of our control. If any of our largest customers experience declining revenues due to market, economic or competitive conditions, we could be pressured to reduce the prices that we charge for our coal, which could have an adverse effect on our margins, profitability, cash flows and financial position. In addition, if any customers were to significantly reduce their purchases of coal from us, including by failing to buy and pay for coal they committed to purchase in sales contracts, our business, financial condition, results of operations and cash flows could be adversely affected.

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. Many utilities have sold their power plants to non-regulated affiliates or third parties that may be less creditworthy, thereby increasing the risk we bear with respect to payment default. These new power plant owners may have credit ratings that are below investment grade. In addition, some of our customers have been adversely affected by the current economic downturn, which may impact their ability to fulfill their contractual obligations. Competition with other coal suppliers could force us to extend credit to customers and on terms that could increase the risk we bear with respect to payment default. We also have a contract to supply coal to an energy trading and brokering customer under which that customer sells coal to end users. If the creditworthiness of our energy trading and brokering customer declines, we may not be able to collect payment for all coal sold and delivered to this customer. If the creditworthiness of our customers declines significantly, 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 customers' contractual obligations are honored. Our inability to collect payment from counterparties to our sales contracts may materially adversely affect our business, financial condition, results of operations, and cash flows.

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 and natural gas liquids. 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 natural 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 for any reason, our natural 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 natural gas. 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 standards change, we might be required to install additional processing equipment which could increase our costs. The pipeline could also curtail our flows until the natural gas delivered to their pipeline is in compliance. Any reduction in our production of natural gas or increase in our costs could materially adversely affect our business, financial condition, results of operations, and cash flows.

Transportation logistics play an important role in allowing us to supply coal to our customers. Any significant delays, interruptions or other limitations on the ability to transport our coal could negatively affect our operations. Our coal is transported from our mining complexes by rail, truck or a combination of these methods. To reach markets and end customers, our coal may also be transported by barge or by ocean vessels loaded at terminals. Disruption of transportation services because of weather-related problems, strikes, lock-outs, terrorism, governmental regulation, third-party action or other events could temporarily impair our ability to supply coal to customers and adversely affect our profitability. In addition, 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 customers' purchasing decision. Increases in transportation costs, including increases resulting from emission control requirements and fluctuation in the price of diesel fuel and demurrage, could make our coal less competitive. Any disruption of the transportation services we use or increase in transportation costs could have a materially adverse effect on our business, financial condition, results of operations, and cash flows.

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 natural 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 natural gas properties for future exploration, limiting our ability to replace the 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.
We compete with other coal producers primarily on the basis of price, coal quality, transportation costs and reliability. We compete with coal producers in various regions of the United States and with some foreign coal producers for domestic sales primarily to electric power generators. Demand for our thermal coal by our principal electric power generator 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. The domestic coal industry has experienced consolidation in recent years, including consolidation among some of our major competitors. In addition, substantial overcapacity exists in the coal industry and several large coal companies have filed, and others may file, bankruptcy proceedings which could enable them to lower their production costs and thereby reduce the price for their coal. We cannot assure you that the result of current or further consolidation in the coal industry or current or future bankruptcy proceedings of our coal competitors will not adversely affect our competitive position. We also compete with both domestic and foreign coal producers for sales in international markets. We sell coal to foreign electricity generators and to the more specialized metallurgical coal market, both of which are significantly affected by international demand and competition. Potential changes to international trade agreements, trade concessions or other political and economic arrangements may benefit coal producers operating in countries other than the United States. We cannot assure you that we will be able to compete on the basis of price or other factors with companies that in the future may benefit from favorable foreign trade

policies or other arrangements.

Any reduction in our ability to compete in natural gas or coal markets could have a material adverse effect on our business, financial condition, results of operations and cash flows.

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) implementation of Phase 1 of the Cross-State Air Pollution Rule (CSAPR) that began in May 2015 with implementation of Phase 2 planned to begin in 2017; (ii) on December 3, 2015 the EPA issued the proposed CSAPR Update Rule to require reductions of seasonal nitrogen oxides (NOX) emissions from power plants in 23 of the original 28 proposed Eastern states to address interstate ozone air quality impacts for downwind states; (iii) on October 1, 2015 the EPA finalized a revised National Ambient Air Quality Standards (NAAQS) for ozone pollution and reduced the limit to 70 parts per billion from the previous 75 parts per billion standard; and (iv) promulgation in 2011 of the Utility Maximum Achievable Control Technology (Utility MACT) rule, better known as the Mercury and Air Toxics Standard (MATS) rule, which included more stringent new source performance standards (NSPS) for particulate matter (PM), mercury, sulfur dioxide (SO2) and nitrogen oxides (NOX), for new and existing coal-fired power plants (amended in November 2014). On June 29, 2015, the U.S. Supreme Court rejected the EPA MATS rule, ruling that the agency unreasonably overlooked the costs associated with the regulation, and sent the rule back to the D.C. Circuit Court to determine whether to remand and allow EPA to address the rule's deficiencies or to vacate and nullify the rule; nevertheless most coal-fired electric power generators have already taken steps to comply with the rule. Six states have filed petitions for review of the new EPA NAAQS ozone pollution standard with the D.C. Circuit Court.

On October 14, 2014, the EPA Clean Water Act Section 316(b) rulemaking went into effect which requires new and existing power plants, including coal and natural gas-fired plants to reduce fish mortality caused by their cooling water intake structures through either the installation of technologies or the reduction of intake velocity.

Apart from actual and potential regulation of emissions, waste water, 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 may increase our operating costs and reduce the value of our natural gas and coal assets and such regulation as well as uncertainty concerning such regulation could adversely impact the market for natural gas and coal as well as for our securities.

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. Other states have elected to participate in voluntary regional cap-and-trade programs like the Regional Greenhouse Gas Initiative (RGGI) in the northeastern U.S.

The EPA, under the Climate Action Plan, has elected to regulate GHGs under the Clean Air Act (CAA) to limit emissions of carbon dioxide (CO2) from coal-fired and natural gas-fired power plants. On September 20, 2013, the EPA re-proposed New Source Performance Standards (NSPS) for CO2 from new power plants and on June 2, 2014, the EPA re-proposed NSPS for CO2 from existing and modified/reconstructed power plants, which rescinded the rules that were originally proposed in 2012. On August 3, 2015, the EPA finalized the Carbon Pollution Standards to cut carbon emissions from new, modified and reconstructed power plants, which became effective on October 23, 2015. In another proposed rulemaking related to CO2 emissions, on June 2, 2014, the EPA proposed the Clean Power Plan Rule to cut carbon emissions from existing power plants. Under this proposed rule, the EPA would create emission guidelines for states to follow in developing plans to address greenhouse gas emissions from existing fossil fuel-fired electric generating units. Specifically, the EPA is proposing state-specific rate-based goals for CO2 emissions from the power sector, as well as guidelines for states to follow in developing plans to achieve the state-specific goals. On August 3, 2015, the EPA finalized the Clean Power Plan Rule to cut carbon pollution from existing power plants, which became effective on December 22, 2015. States, industry and labor organizations have filed at least 17 petitions for review in the D.C. Circuit Court of Appeals requesting that the Court stay implementation of the rule.

Internationally, the Kyoto Protocol, which set binding emission targets for developed countries (which was not ratified by the United States) 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. In December 2015, the United Nations Climate Change Conference was held and an agreement was reached between the countries participating in the conference, including the United States, to limit global warming to less than 2 degrees Celsius (3.6° Fahrenheit) compared to pre-industrial levels. This agreement, known as the Paris Agreement, calls for zero net anthropogenic greenhouse gas emission to be reached during the second half of the 21$^{st}$ century. Each party is to prepare a plan on its contributions to reach this goal; each plan is to be filed in a publicly available registry. To become effective, at least 55 countries, representing at least 55 percent of global greenhouse emissions, must sign the agreement in New York between April 22, 2016 and April 21, 2017, and adopt it within their own legal systems through ratification, acceptance, approval or accession.

Additionally, 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 natural 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.

Apart from governmental regulation, investment banks based both domestically and internationally have announced that they have 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. In addition, banks have also adopted more stringent lending requirements of surface coal operations which may make it more difficult to obtain financing by coal operators.

Adoption of comprehensive legislation or regulation focusing on GHG emission reductions for the United States or other countries where we sell coal (including by adopting plans to implement the Paris Agreement), or the inability of utilities to obtain financing in connection with coal-fired plants, 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, there have also been efforts in recent years affecting the investment community, including investment advisors, sovereign wealth funds, public pension funds, universities and other groups, promoting the divestment of fossil fuel equities and also pressuring lenders to limit funding to companies engaged in the extraction of fossil fuel reserves. The impact of such efforts may adversely affect the demand for and price of securities issued by us, and impact our access to the capital and financial markets.

Environmental regulations introduce uncertainty that could adversely impact the market for natural gas and coal with potential short and long-term liabilities.

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. In April 2015, the US Fish and Wildlife Service (USFWS) announced a Section 4(d) threatened listing final rule for the Northern Long-Eared Bat throughout our operations area. This listing could lead to significant timing and critical path hurdles, ultimately limiting the ability to clear timber for construction activities.

Other species that are being considered for listing as endangered under the ESA are the Big Sandy Crayfish, the Guyandotte River Crayfish and the Rusty Patched Bumble Bee, all of which if listed have the potential to interfere with the proposed layout of our mine plans and surface facilities, including gas well pads, compressor stations and pipelines, as well as the manner in which we operate our mines and facilities. USFWS has stated that the primary threats to crayfishes throughout their respective ranges are land-disturbing activities that increase erosion and sedimentation, which degrades the stream habitat required by both species. Identified sources of ongoing erosion and sedimentation that occur throughout the ranges of the species include active surface coal mining, commercial forestry, unpaved roads, natural gas and oil development, and road construction. This has the potential to disrupt future mining and natural gas activities in Appalachia.

The Office of Surface Mining has issued proposed amendments to regulations concerning stream buffer zones, stream channel diversions, excess spoil, and coal mine waste to comply with an order issued by the U.S. District Court for the District of Columbia on February 20, 2014, which vacated the stream buffer zone rule that was published December 12, 2008. On July 27, 2015, OSM published the proposed Stream Protection Rule. The proposed rule includes changes that amount to a rewrite of the existing rule on a nationwide scale and that adds and revises regulations for surface mines, underground mines and ancillary facilities located in every coal producing state. Additionally, OSM proposes to extend the impacts of mining to include surrounding areas of the entire reserve, previously not included in assessments submitted with our permits for active mining. The proposed rule would also prohibit mining in or through a perennial, intermittent, or ephemeral stream, even if the effects are temporary, and to require a 100 foot buffer zone on each side of a stream, which has the potential to sterilize the coal under those streams as unmineable. As drafted, this proposed rule has the potential to impact the profitability of our longwall coal mines.

The Company’s natural gas, water, and coal businesses must obtain permits with associated mitigation from the Army Corps of Engineers (ACOE) for impacts to streams and wetlands that are unavoidable. In 2013, the EPA issued a draft report entitled Connectivity of Streams and Wetlands to Downstream Waters, which affects a proposed rulemaking known as the WOTUS rule that would expand the scope of the Clean Water Act (CWA) to include previously non-jurisdictional streams, wetlands, and waters, making these areas jurisdictional inter-coastal Waters of the U.S. On June 29, 2015, the EPA published the final WOTUS Rule which was to become effective on August 28, 2015. However, on August 27, 2015, the District Court for the District of North Dakota blocked implementation of the rule in 13 states. On October 9, 2015, the U.S. Circuit Court of Appeals for the Sixth Circuit blocked implementation of the rule nationwide.

Management and regulation of point source discharges covered under the National Pollutant Discharge Eliminations System (NPDES) of the CWA have undergone recent changes and proposed changes at both the state and federal level that have the potential to affect the long term treatment and discharge of water from coal mines. States are required by the CWA to conduct a comprehensive review of the state water quality standards every three years (the "Triennial Review"). WV has issued an emergency rule effective June 21, 2014 and proposed amendments under 47 CSR 2 with specific requirements for the discharge of aluminum and selenium that pose potential impacts on the coal industry. Ohio (OH) is currently reviewing the current 401 and 404 permitting program to propose new amendments.

In April 2015, the EPA proposed a CWA regulation (Effluent Limitations Guidelines and Standards for the Oil and Gas Extraction Point Source Category) establishing pretreatment standards that would prohibit the indirect discharge of wastewater from onshore unconventional oil and gas extraction facilities to publicly owned treatment works (POTWs). While discharges to POTWs are not currently utilized, unconventional oil and gas extraction wastewater can be generated in large quantities. It is unclear how the newly proposed rule could affect future water use and disposal practices.

Federal and state regulations for horizontal well drilling and well site construction have been proposed and are currently being considered. On April 4, 2015, PA published an advanced notice of final rulemaking on revisions to the

Environmental Protection Performance Standards at Oil and Gas Well Sites (Chapters 78 and 78a) that could have significant impacts on how oil and natural gas companies currently operate in PA. On June 26, 2015, WV proposed amendments to regulations under 35 WVCSR 8 regarding standards for Horizontal Well Development. In May 2015, OH passed Horizontal Well Site Construction Rules which will become effective in July 2015. OH is also in the process of reviewing and possibly adopting additional horizontal development rules.

Our natural gas and coal mining operations are subject to operating risks, including our reliance upon third party contractors, 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 natural 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 natural 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. Underground mining and related processing activities present inherent risks of injury to persons and damage to property and equipment. Our 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 an operating risk occurs in our mining operations, we may not be able to produce sufficient amounts of coal to deliver under our multi-year coal contracts. Our inability to satisfy contractual obligations could result in our customers initiating claims against us or canceling their contracts. The operating risks that may have a significant impact on our coal operations include:

- variations in thickness of the layer, or seam, of coal;
- adverse geological conditions, including amounts of rock and other natural materials intruding into the coal that could affect the stability of the roof and the side walls of the mine - for example, unit costs were negatively impacted in 2014 due to adverse geological conditions at the Enlow Fork mine, primarily related to sandstone intrusions, along with adverse geological conditions and equipment issues at the Harvey mine, primarily related to sandstone intrusions, which resulted in reduced coal production at both the Enlow Fork and Harvey mines;
- environmental hazards;
- equipment failures or unexpected maintenance problems;
- fires or explosions, including as a result of methane, coal, coal dust or other explosive materials and/or other accidents;
- inclement or hazardous weather conditions and natural disasters or other force majeure events;
- seismic activities, ground failures, rock bursts or structural cave-ins or slides;
- delays in moving our longwall equipment;
- railroad derailments;
- security breaches or terroristic acts; and
- other hazards that could also result in personal injury and loss of life, pollution and suspension of operations.

The occurrence of any of these risks at our natural gas or coal mining operations could adversely affect our ability to conduct natural gas or coal mining operations or result in substantial loss to us as a result of claims for:

- personal injury or loss of life;
-

- damage to and destruction of property, natural resources and equipment, including our coal properties and our coal production or transportation facilities;
- pollution and other environmental damage to our properties or the properties of others;
- potential legal liability and monetary losses;
- regulatory investigations and penalties;
- suspension of our operations; and
- repair and remediation costs.

In addition, the occurrence of any of these events in our coal mining operations which prevents our delivery of coal to a customer and which is not excusable as a force majeure event under our coal sales agreement, could result in economic penalties, suspension or cancellation of shipments or ultimately termination of the coal sales agreement.

Although we maintain insurance for a number of risks and hazards, we may not be insured or fully insured against the losses or liabilities that could arise from a significant accident in our natural gas and coal operations. We may elect not to obtain insurance for any or all of these risks if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. Moreover, a significant mine accident could potentially cause a mine shutdown. The occurrence of an event that is not fully covered by insurance could have a material adverse effect on our business, financial condition, results of operations and cash flows.

We also 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 natural gas and coal segments. We also use third party contractors to provide construction and specialized services to our coal 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 natural gas and coal production, increase our costs of natural gas and coal production, and decrease our anticipated profitability.

We attempt to mitigate the risks involved with increased natural gas 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 during a downturn in demand or during periods of oversupply. For example, in 2015 due to the oversupply of gas in our markets, we made payments under these contracts of approximately $19 million for field services that we did not use which would decrease our cash flow and raise our costs of production. Having to pay for services we do not use decreases our cash flow and increases our costs of production.

We may not be able to obtain equipment, parts and raw materials in a timely manner, in sufficient quantities or at reasonable costs to support our coal mining and transportation operations.

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 use equipment in our coal mining and transportation operations such as continuous mining units, conveyors, shuttle cars, rail cars, locomotives, roof bolters, shearers and shields. We procure this equipment from a concentrated group of suppliers, and obtaining this equipment often involves long lead times. Occasionally, demand for such equipment by mining companies can be high and some types of equipment may be in short supply. Delays in receiving or shortages of this equipment, as well as the raw materials used in the manufacturing of supplies and mining equipment, which, in some cases, do not have ready substitutes, or the cancellation of our supply contracts under which we obtain equipment and other consumables, could limit our ability to obtain these supplies or equipment. In addition, if any of our suppliers experiences an adverse event, or decides to no longer do business with us, we may be unable to obtain sufficient equipment and raw materials in a timely manner or at a reasonable price to allow us to meet our production goals and our revenues may be adversely impacted. We use considerable quantities of steel in the mining process. If the price of steel or other materials increases substantially or if the value of the U.S. dollar declines relative to foreign currencies with respect to certain imported supplies or other products, our operating expenses could increase. Any of the foregoing events could materially and adversely impact our business, financial condition, results of operations, or cash flows.

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

Our coal production is dependent on our ability to obtain various federal and state permits and approvals to mine our coal reserves. The permitting rules, and the interpretations of these rules, are complex, change frequently, and are often subject to discretionary interpretations by regulators. The EPA also has the authority to veto permits issued by the U.S. Army Corps of Engineers under the Clean Water Act’s Section 404 program that prohibits the discharge of dredged or fill material into regulated waters without a permit. In addition, the public, including non-governmental organizations and individuals, have certain statutory rights to comment upon and otherwise impact the permitting process, including through court intervention. 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 where our Virginia Operations are located. Environmental groups in Southern West Virginia and Kentucky have challenged state and U.S. Army Corps of Engineers (ACOE) 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 2011, the EPA revoked an ACOE-issued Section 404 permit to a coal mining operator. Following the U.S. Supreme Court’s refusal in March 2012 to hear an appeal from the D.C. Circuit Court’s ruling upholding the EPA’s power to revoke a permit, in September 2014 the U.S. Court of Appeals upheld the EPA’s action to revoke the permit. In addition, in July 2014 the D.C Circuit reversed a lower court’s decision and affirmed the EPA’s authority to adopt the Enhanced Coordination Process governing coordination with the ACOE in the processing of CWA permits. The Court also rejected challenges to EPA’s 2012 “Final Guidance” document regarding appropriate permit conditions, namely those affecting acceptable conductivity limits (e.g., acceptable ionic strength to support aquatic life). However, the Court left it up to the states on whether to adopt the guideline recommendations when issuing final NPDES permits. This decision has left coal mining permits in some degree of uncertainty whether the EPA will concur with a state’s draft permit conditions should they not contain specified limits regarding conductivity, further increasing operational uncertainty and costs.

The pace with which the government issues permits needed for new operations and for on-going operations to continue coal mining has negatively impacted expected production. These delays or denials of coal mining permits could reduce our production, cash flows and results of operations.

In addition, in 2005, the Pennsylvania Department of Environmental Protection (“PADEP”) issued a technical guidance document that imposes standards in the material mining permits that we hold relating to our Pennsylvania Operations, including potentially costly stream mitigation and monitoring requirements and alterations to our longwall mining plans. We have filed permit appeals challenging the PADEP’s use and application of the technical guidance document to our coal mines, which we expect to be resolved by later this year. If these challenges are unsuccessful, we could incur material costs to comply with the technical guidance document requirements, including costs to avoid streams and other water bodies of concern. In addition, we may be required to alter our mine plans, which could result in a reduction in our accessible reserves in the affected mines.

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. At CONSOL Energy’s Fola Mining Operations, six citizen suits have been filed challenging water discharge permits. Two of those suits were settled in 2014, and at least two are potentially affected by recent settlements by another mining operator in a similar case.

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 natural 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 and a final report was to be issued in 2015 along with stated accompanying regulation.

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. Additionally, revisions were made 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. Section 111 of the CAA authorized the EPA to develop technology based standards which apply to specific categories of stationary sources. 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 natural gas wells, coal mines and associated facilities.

The EPA has proposed to amend the Petroleum and Natural Gas Systems source category (Subpart W) of the Greenhouse Gas Reporting Program (GHGRP). This proposed rule would add reporting of greenhouse gas emissions from certain gathering and boosting systems, completions and workovers of oil wells using hydraulic fracturing, and blowdowns of natural gas transmission pipelines. The rule would also require operators to utilize new monitoring equipment in order to comply with Subpart W. On September 18, 2015, the EPA proposed updates to the New Source Performance Standards (NSPS) that would create new standards for the regulation of methane and VOC emission sources. The proposed rule includes requirements for new fugitive emission and leak detection testing and reporting requirements. On September 18, 2015, the EPA proposed the Source Determination Rule which would clarify the use of the term “adjacent” in determining Title V air permitting requirements as they apply to the oil and natural gas industry for major sources of air emissions. 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.

Further, air emissions that stem from hydraulic fracturing and completions processes, as well as from midstream activities such as the gathering and transmission of natural gas, are regulated by federal and state rules. However, interpretations of those rules, as well as additional changes to the regulations, could negatively impact our ability to meet our stated production objectives for the company. For example, source aggregation of air emissions to determine whether, under the Clean Air Act a source comprises a single stationary source and is therefore a major source of air pollution, and thereby subject to the applicability of Nonattainment Prevention of Significant Deterioration and Title V permitting requirements, has and continues to be debated by the EPA, state regulatory agencies and the courts. Recently, the Pennsylvania Environmental Hearing Board determined the emission sources of an upstream subsidiary and a midstream subsidiary of a company were aggregated as a single source, given the dynamic nature of the issue. Federal and state activities as well as court decisions could impact the development and transmission of plans of CONSOL Energy, our joint venture partners, and gathering systems being installed and operated by CONE Midstream Partners, LP.

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 Ohio 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. Further, states could elect to prohibit hydraulic fracturing altogether, as Governor Andrew Cuomo of the State of New York announced in December 2014 with regard to fracturing activities in New York. 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 natural gas properties, all of which could have a materially 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 natural 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 natural 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.

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.

The Federal Coal Mine Safety and Health Act and Mine Improvement and New Emergency Response Act impose stringent health and safety standards on mining operations. Regulations that have been adopted are comprehensive and affect numerous aspects of mining operations, including training of mine personnel, mining procedures, the equipment used in mine emergency procedures and other matters. Most states in which we operate have programs for mine safety and health regulation and enforcement. The various requirements mandated by law or regulation can place restrictions on our methods of operations, and potentially lead to fees and civil penalties for the violation of such requirements, 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 an incident were to occur at one of our coal mines, it could be shut down 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 coal refuse areas and slurry impoundments at a number of our coal 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. We have several operations with selenium discharges. We and other coal companies have worked to expeditiously develop cost effective means to remove selenium from mine water.

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, as well as silica dust associated with natural gas well completions activities.

We have 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 our coal mining operations. Also, state laws require us to plug natural gas wells and reclaim well sites after the useful life of our natural gas wells has ended. We accrue 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 $550 million at December 31, 2015. The amounts recorded are dependent upon a number of variables, including the estimated future closure costs, estimated proved reserves, assumptions involving profit margins, inflation rates, and the assumed credit-adjusted risk-free interest rates. 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 we must seek in order to permit its mining activities.

We have been able to post surety bonds with the states to secure our reclamation obligations. If our creditworthiness declines, states may seek to require us to post letters of credit or cash collateral to secure those obligations, or we may be unable to obtain surety bonds, in which case we would be required to post letters of credit. Posting letters of credit in place of surety bonds would have an adverse affect on our liquidity.

We face uncertainties in estimating our economically recoverable natural gas, oil and coal reserves, and inaccuracies in our estimates could result in lower than expected revenues, higher than expected costs and decreased profitability.

Natural gas and oil and coal reserves are economically recoverable when the price at which they are expected to be sold exceeds their expected cost of production and selling.

Natural gas and oil reserves require subjective estimates of underground accumulations of natural gas and oil and assumptions concerning natural gas and oil prices, production levels, reserve estimates and operating and development costs. As a result, estimated quantities of proved natural gas and oil reserves and projections of future production rates and the timing of development expenditures may be incorrect. For example, a significant amount of our proved undeveloped reserves extensions and discoveries during the last three years were due to the addition of wells on our Marcellus Shale acreage more than one offset location away from existing production with reliable technology, which may be more susceptible to positive and negative changes in reserve estimates than our proved developed reserves. 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 and oil 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 natural gas reserves, the economically recoverable quantities of natural gas attributable to any particular group of properties, the classifications of natural gas and oil 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 natural 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 natural gas reserves on historical average prices and costs. However, actual future net cash flows from our natural 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 and oil 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 natural gas reserves as of December 31, 2015 would decrease from $1.7 billion to $1.5 billion.

We base our reserve information on geologic data, coal ownership information and current and proposed mine plans. These estimates are periodically updated to reflect past coal production, new drilling information and other geologic or mining data. Similar to natural gas and oil reserves, 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:

- geologic conditions;
- historical production from the area compared with production from other producing areas;
- the assumed effects of regulations and taxes by governmental agencies;
- our ability to obtain, maintain and renew all required permits;
- future improvements in mining technology;
- assumptions governing future prices; and
- future operating costs, including the cost of materials and capital expenditures.

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 natural gas, particularly by horizontal drilling. If a natural gas 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 natural gas reserves than a vertical well which could result in higher costs. In future years, the cost associated with purchasing oil and natural 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 natural gas and coal reserves may vary substantially. Actual production, revenues and expenditures with respect to our coal and natural 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 natural gas reserves.

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

Substantial amounts of acreage in which we believe we control natural gas rights are in areas where we have not yet done a thorough chain of title examination of the natural gas estate. A number of our natural 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 natural gas rights in substantial acreage from third parties who had not performed thorough chain of title work on their natural gas properties. Our practice, and we believe industry practice, is not to perform a thorough title examination on natural 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 natural 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 of 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 natural 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 requires 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.

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, natural 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.

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

We provide various long-term employee benefits to inactive and retired employees. We accrue amounts for these obligations. At December 31, 2015, the current and non-current portions of these obligations included:

- postretirement medical and life insurance ($672 million);
- coal workers' black lung benefits ($123 million);
- salaried retirement benefits ($94 million); and
- workers' compensation ($83 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 a settlement expense adjustment equaling the unrecognized actuarial gain or loss resulting from each individual who received a lump sum in that year. For example, in 2015 CONSOL Energy had settlement expense of $19 million. If the settlement is triggered in future periods, it may be material to operating results.

We do not control the timing of divestitures that we plan to engage in and they may not provide anticipated benefits.

Our business and financing plans include divesting over $1.0 billion of certain assets. However, we do not control the timing of divestitures and delays in entering into divestitures may reduce the benefits from them. Also, there can be no assurance that the assets we divest will produce anticipated proceeds. In addition, the terms of divestitures may cause 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 natural 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 operations; and we may not realize the benefits we expect to realize from these joint ventures.

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

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 completely 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 development 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. If our joint venture partners are unable or fail to pay their portion of development costs, our costs of operations could be increased, it could result in reduced drilling and production of oil and natural gas or loss of rights to develop the oil and natural gas properties held by that joint venture. 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.

One of the potential benefits of these two joint ventures was the obligation of the other party to pay a portion of our share of drilling and development costs for new wells, which we called "carried costs." At December 31, 2015 Noble Energy has a remaining carried costs obligation of approximately $1.6 billion while Hess's remaining carried costs obligation was $1.7 million. 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 from December 1, 2011 to March 1, 2014 and was again suspended on November 1, 2014 and remained suspended throughout 2015. We cannot predict when this latest 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 expected to receive in the transaction. When the carry obligation is in effect, the benefits we receive from it would also depend upon the rate at which new wells are drilled and developed in the Noble Energy joint venture, which could fluctuate significantly from period to period. Moreover, the performance of the carry obligation is outside our control.

The Hess joint development agreement provides that any transfer of interest in the joint venture by us or Hess will be subject to a right of first offer in favor of the other party. 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, liquidity and results of operations.

As of December 31, 2015, our total long-term indebtedness was approximately $2.79 billion of which approximately $1.85 billion was under our 5.875% senior unsecured notes due 2022 plus $6 million of unamortized bond premium, $500 million was under our 8.000% senior unsecured notes due 2023 less $7 million of unamortized bond discount, $74 million was under our 8.250% senior unsecured notes due 2020, $21 million was under our 6.375% senior unsecured 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, $43 million of capitalized leases due through 2021, $13 million of miscellaneous debt and $185 million in outstanding borrowings under the revolver for CNXC of which we are not a guarantor. 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;
- requiring us to dedicate a substantial portion of our cash flow from operations to the payment of interest and principal due under our outstanding debt, which will limit 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;
- placing us at a competitive disadvantage compared to our competitors with lower leverage and better access to capital resources; and
- limiting our ability to implement our business strategy.

Our senior secured credit facility and the indentures governing our 5.875% and 8.000% senior unsecured notes limit the incurrence of additional indebtedness unless specified tests or exceptions are met. In addition, our senior secured credit agreement and the indentures governing our 5.875% and 8.000% senior unsecured notes subject us to financial and/or other restrictive covenants. Under our senior secured credit agreement, we must comply with certain financial covenants on a quarterly basis including a minimum interest coverage ratio, and a minimum current ratio, as defined therein. Our senior secured credit agreement and the indentures governing our 5.875% and 8.000% senior unsecured notes impose a number of restrictions upon us, such as restrictions on granting liens on our assets, making investments, paying dividends, stock repurchases, 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 a material 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 5.875% and 8.000% 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 natural gas and oil reserves, our natural gas and oil reserves and production will decline, which would adversely affect our business, financial condition, results of operations and cash flows.

Producing natural gas and oil 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, 2015, 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 and oil 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 lenders use the loan value of our proved natural gas and oil reserves to determine the borrowing base under our $2.0 billion senior secured credit facility. Our borrowing base could decrease for a variety of reasons including lower natural gas or oil prices, declines in natural gas and oil proved reserves, and lending requirements or regulations. Significant reductions in our borrowing base below $2.0 billion could have a material adverse effect on our results of operations, financial condition and liquidity.

Our ability to borrow and have letters of credit issued under our $2.0 billion senior secured credit facility is generally limited to a borrowing base. Our borrowing base is determined by the required number of lenders in good faith calculating a loan value of the Company's proved gas and oil reserves. The borrowing base under our senior secured credit facility is currently $2.0 billion. Our borrowing base is redetermined by the lenders twice per year, and the next scheduled borrowing base redetermination is expected to occur in May 2016. The various matters which we describe in other risk factors that can decrease our proved natural gas and oil reserves including lower natural gas or oil prices, operating difficulties, and failure to replace our proved reserves could decrease our borrowing base. Please read: "Risk Factors - We face uncertainties in estimating our economically recoverable natural gas, oil and coal reserves, and inaccuracies in our estimates could result in lower than expected revenues, higher than expected costs and decreased profitability" and - "Unless we replace our natural gas and oil reserves, our natural gas and oil reserves and production will decline, which would adversely affect our business, financial condition, results of operations and cash flows." Our borrowing base could also decrease as a result of new lending requirements or regulations or the issuance of new indebtedness. If our borrowing base declined significantly below $2.0 billion, we may be unable to implement our drilling and development plans, make acquisitions or otherwise carry out our business plan which could have a material adverse effect on our financial condition and results of operation. We also could be required to repay any indebtedness in excess of the redetermined borrowing base. We could face substantial liquidity problems, might not be able to access the equity or debt capital markets and might be required to sell material assets or operations to attempt to meet our debt service and other obligations. 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.

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 15, 2016, we had hedges on approximately 223.6 Bcf of our 2016 natural gas production, 156.7 Bcf of our 2017 natural gas production and 75.8 Bcf of our 2018 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.

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.

Additionally, legislation has been proposed in Ohio and Pennsylvania to introduce a new severance tax on the oil and gas industry. The proposed rates have varied from 2.5 - 7.5 percent and would represent a significant increased financial burden on the economics of the wells we drill in these states.

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. Additionally, our development and exploration projects require substantial capital expenditures and if we fail to obtain required capital or financing on satisfactory terms, our natural gas reserves may decline.

Our future growth prospects are dependent upon our ability to identify optimal strategies for our business. In developing our business plan, we consider 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 consider our likely sources of capital, including cash generated from operations and borrowings under our credit facilities. 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.

As part of our strategic determinations, we expect to continue to make substantial capital expenditures in the development and acquisition of natural gas reserves. We cannot assure you that we will have sufficient cash from operations, borrowing capacity under our credit facilities or the ability to raise additional funds in the capital markets. If cash flow generated by our operations or available borrowings under our credit facilities are not sufficient to meet our capital requirements, or we are unable to obtain additional financing, we could be required to curtail the pace of the development of our natural gas properties, which in turn could lead to a decline in our reserves and production, and could adversely affect our business, financial condition and results of operations.

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, or under various agreements with us, could materially increase our liabilities and materially adversely affect our results of operations, financial position and cash flows.

In 2013, Murray Energy and its subsidiaries (Murray Energy) acquired approximately $2.4 billion of liabilities which had been reflected on our books. The consolidated balance sheet liabilities at the time of sale were comprised of approximately $2.1 billion of OPEB and other liabilities. In addition to these assumed liabilities, (i) Murray Energy acquired our obligations to make payments per hour worked to 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, (iii) we leased or subleased various mining equipment to Murray Energy, and (iv) we guaranteed performance by Murray Energy of certain coal supply agreements that Murray Energy acquired in the transaction. At the time of sale, if the hourly payment obligations acquired by Murray Energy to the 1974 Pension Plan were to be capitalized, they would have had a present value of approximately $941 million, assuming a discount rate of 4.02%. Our maximum estimated exposure under our Murray Energy guarantees as of December 31, 2015 was approximately $123 million. The leases and subleases we entered into with Murray Energy relate to approximately $156 million of equipment. Murray Energy is primarily liable for the acquired retiree medical liabilities under the Coal Industry Retiree Health Benefits Act of 1992, which we call the Coal Act, but CONSOL Energy remains secondarily liable. At the time of the sale, the Coal Act liabilities Murray Energy acquired were approximately $307 million and it was estimate that the servicing cost for these liabilities would be approximately $27 million for 2016 and would decline thereafter since the beneficiaries principally are miners who retired prior to 1994. 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 a rating of Caa1 (poor standing and subject to very high credit risk). In November, 2015, Moody’s downgraded Murray Energy to a family credit rating of Caa1 and the rating on its secured second lien notes to Caa2 with a negative outlook. 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 if, successful, could materially adversely affect our results of operations, financial position and cash flows. In addition, we 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 guaranteed, our cash flows may also be materially impacted.

Terrorist attacks or a cyber incident could result in information theft, data corruption, operational disruption and/or financial loss.

We have become increasingly dependent upon digital technologies, including information systems, infrastructure and cloud applications and services, to operate our businesses, to process and record financial and operating data, communicate with our employees and business partners, analyze seismic and drilling information, estimate quantities of oil and gas reserves and coal reserves, as well as other activities related to our businesses. Strategic targets, such as energy-related assets, may be at greater risk of future physical attacks by terrorists or cyber attacks than other targets in the United States. Deliberate attacks on our assets, or security breaches in our systems or infrastructure, or the systems or infrastructure of third parties, or the cloud could lead to corruption or loss of our proprietary data and potentially sensitive data, delays in production or delivery, difficulty in completing and settling transactions, challenges in maintaining our books and records, environmental damage, communication interruptions, other operational disruptions and third party liability. Our insurance may not protect us against such occurrences. Consequently, it is possible that any of these occurrences, or a combination of them, could have a material adverse effect on our business, financial condition and results of operations. Further, as cyber incidents continue to evolve, we may be required to expend additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerability to cyber incidents.

A substantial majority of sales of thermal coal and high volatile metallurgical coal are from three mines at one location in Pennsylvania while a substantial majority of our low volatile metallurgical coal is from one mine located in Virginia, making us vulnerable to risks associated with operating in a single geographic area.

The substantial majority of our sales of thermal coal and high volatile metallurgical coal, as well as our thermal coal reserves, are from our Bailey, Enlow Fork and Harvey underground mining complexes located in Greene County, Pennsylvania. In addition, we also rely upon one coal processing plant and rail load facility, located in Enon, Pennsylvania for shipping coal from all of these mines. Any disruption in the functioning of this coal processing plant and rail load-out facility such as the structural failure at the above ground conveyor system which occurred in 2012 or in transportation in this area could significantly reduce our sales of thermal and high volatile metallurgical coal and adversely affect our results of operation and financial condition.

Similarly, the substantial majority of our low volatile metallurgical coal sales, as well as our low volatile metallurgical coal reserves, are from our Buchanan mine located in Mavisdale, Virginia. Any disruption in the functioning of this mine (such as the 2007 mine incident which idled the Buchanan mine for approximately nine months) or transportation in this area could significantly reduce our sales of low volatile metallurgical coal and adversely affect our results of operation and financial condition.

Certain provisions in our multi-year sales contracts may provide limited protection during adverse economic conditions, may result in economic penalties to us or permit the customer to terminate the contract.
Price adjustment, “price reopener” and other similar provisions in our multi-year sales contracts may reduce the protection from coal price volatility traditionally provided by coal supply contracts. Price reopener provisions are present in several of our multi-year sales contracts. These price reopener provisions may automatically set a new price based on prevailing market price or, in some instances, require the parties to agree on a new price, sometimes within a specified range of prices. In a limited number of agreements, failure of the parties to agree on a price under a price reopener provision can lead to termination of the contract. Any adjustment or renegotiations leading to a significantly lower contract price could adversely affect our profitability.

Most of our sales agreements contain provisions requiring us to deliver coal within certain ranges for specific coal characteristics such as heat content, sulfur, ash, moisture, volatile matter, grindability, chlorine and ash fusion temperature. Failure to meet these conditions could result in penalties or rejection of the coal at the election of the customer. Our sales contracts also 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, floods, earthquakes, storms, fire, faults in the coal seam or other geologic conditions, other natural catastrophes, wars, terrorist acts, civil disturbances or disobedience, strikes, railroad transportation delays caused by a force majeure event and actions or restraints by court order and governmental authority or arbitration award. 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 and some contracts may obligate us to perform notwithstanding what would typically be a force majeur event.

Our common units in CNX Coal Resources LP and CONE Midstream Partners LP are subordinated to other common units and we may not receive distributions from CNX Coal Resources LP or CONE Midstream Partners LP.

We hold 11.6 million subordinated units (representing a 49.0 percent limited partnership interest) in CNX Coal Resources LP, which we call CNXC. The balance of CNXC’s limited partnership interests are held in the form of common units. Subordinated units are not entitled to any distribution from CNXC unless CNXC makes a minimum quarterly distribution on its common units of $0.5125 per unit (or in the case of its first fiscal quarter since its initial public offering in July 2015, a prorated portion of this amount). CNXC met this requirement with respect to its first fiscal quarter ended September 30, 2015 and we received a distribution per subordinated unit equal to the distribution per common unit. However, we cannot assure you that CNXC will continue to be able to make or will make the required minimum quarterly distribution on its common units or that we will receive any future distributions on our subordinated units. Failure by CNXC to make distributions to us on our subordinated units could adversely affect our liquidity.

We hold 14.6 million subordinated units (representing 24.5 percent limited partnership interest) in CONE Midstream Partners LP, which we call CONE. The balance of CONE's limited partnership interests are held either by NOBLE Energy or in the form of common units. Subordinated units are not entitled to any distribution from CONE unless CONE makes a minimum quarterly distribution on its common units of $0.2125 per unit. CONE has met this requirement with respect to each of its fiscal quarters and we received a distribution per subordinated unit equal to the distribution per common unit. However, we cannot assure you that CONE will continue to be able to make or will make the required minimum quarterly distribution on its common units or that we will receive any future distributions on our subordinated units. Failure by CONE to make distributions to us on our subordinated units could adversely affect our liquidity.

ITEM 1B. Unresolved Staff Comments

None.

ITEM 2. Properties

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

ITEM 3. Legal Proceedings

The first through the ninth 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

The Company's 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, 2015 | | | |
| Quarter Ended March 31, 2015 | $34.56 | $26.11 | $0.0625 |
| Quarter Ended June 30, 2015 | $34.14 | $21.44 | $0.0625 |
| Quarter Ended September 30, 2015 | $22.04 | $9.29 | $0.0100 |
| Quarter Ended December 31, 2015 | $11.99 | $6.30 | $0.0100 |
| Year Period Ended December 31, 2014 | | | |
| Quarter Ended March 31, 2014 | $41.51 | $35.72 | $0.0625 |
| Quarter Ended June 30, 2014 | $48.30 | $39.08 | $0.0625 |
| Quarter Ended September 30, 2014 | $46.61 | $35.96 | $0.0625 |
| Quarter Ended December 31, 2014 | $42.26 | $31.64 | $0.0625 |

As of December 31, 2015, there were 135 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., Arch Coal Inc., Chesapeake Energy Corp., Devon Energy Corp., EOG Resources Inc., Noble Energy Inc., Peabody Energy Corp., Southwestern Energy Co., QEP Resources Inc., and WPX Energy, Inc., Teck Resources Limited, EQT, Range Resources Corp., Cabot Oil & Gas Corp., and Antero Resources Corp. The graph assumes that the value of the investment in CONSOL Energy common stock and each index was $100 at December 31, 2010. The graph also assumes that all dividends were reinvested and that the investments were held through December 31, 2015.

| | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 |
|---|---|---|---|---|---|---|
| CONSOL Energy Inc. | 100.0 | 75.5 | 66.5 | 78.1 | 69.3 | 16.3 |
| Peer Group | 100.0 | 87.9 | 85.1 | 97.6 | 67.2 | 30.7 |
| S&P 500 Stock Index | 100.0 | 100.1 | 111.5 | 144.5 | 161.0 | 159.9 |

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. The Company's credit facility limits CONSOL Energy's ability to pay dividends in excess of an annual rate of $0.50 per share when the Company's leverage ratio exceeds 3.50 to 1.00 and subject to an aggregate amount up to the then cumulative credit calculation. The total leverage ratio was 3.63 to 1.00 and the cumulative credit was approximately $917 million at December 31, 2015. The calculation of this ratio excludes CNXC. The credit facility does not permit dividend payments in the event of default. The indentures to the 2022 and 2023 notes limit dividends to $0.50 per share annually unless several conditions are met. These 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, 2015.
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, 2015, 2014, 2013, 2012 and 2011 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, 2015 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 Item 7 "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, | | | | |
|---|---|---|---|---|---|
| | 2015 | 2014 | 2013 | 2012 | 2011 |
| Operating revenues from Continuing Operations | $2,893,923 | $3,476,100 | $3,120,722 | $3,282,350 | $4,237,913 |
| (Loss) Income from Continuing Operations | $(364,475) | $168,777 | $79,264 | $317,959 | $681,675 |
| Net (Loss) Income Attributable to CONSOL Energy Inc. Shareholders | $(374,885) | $163,090 | $660,442 | $388,470 | $632,497 |
| Earnings (Loss) per share: | | | | | |
| Basic: | | | | | |
| (Loss) Income from Continuing Operations | $(1.64) | $0.73 | $0.35 | $1.40 | $3.01 |
| (Loss) Income from Discontinued Operations | — | (0.02) | 2.54 | 0.31 | (0.22) |
| Net (Loss) Income | $(1.64) | $0.71 | $2.89 | $1.71 | $2.79 |
| Dilutive: | | | | | |
| (Loss) Income from Continuing Operations | $(1.64) | $0.73 | $0.35 | $1.39 | $2.98 |
| (Loss) Income from Discontinued Operations | — | (0.03) | 2.52 | 0.31 | (0.22) |
| Net (Loss) Income | $(1.64) | $0.70 | $2.87 | $1.70 | $2.76 |
| | | | | | |
| Assets from Continuing Operations | $10,929,902 | $11,654,646 | $11,147,935 | $9,748,879 | $9,254,210 |
| Assets from Discontinued Operations | — | — | — | 2,614,251 | 2,573,623 |
| Total Assets | $10,929,902 | $11,654,646 | $11,147,935 | $12,363,130 | $11,827,833 |
| | | | | | |
| Long-Term Debt from Continuing Operations (including current portion) | $2,754,855 | $3,250,578 | $3,140,585 | $3,143,722 | $3,147,395 |
| Long-Term Debt from Discontinued Operations (including current portion) | — | — | — | 2,574 | 1,659 |
| Total Long-Term Debt (including current portion) | $2,754,855 | $3,250,578 | $3,140,585 | $3,146,296 | $3,149,054 |
| Cash Dividends Declared Per Share of Common Stock | $0.145 | $0.250 | $0.375 | $0.625 | $0.425 |

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, | | | | |
|---|---|---|---|---|---|
| | 2015 | 2014 | 2013 | 2012 | 2011 |
| Gas: | | | | | |
| Net sales volumes produced (in billion cubic feet equivalent) | 328.7 | 235.7 | 172.4 | 156.3 | 153.5 |
| Average sales price ($ per Mcfe)(A) | $2.81 | $4.37 | $4.30 | $4.22 | $4.90 |
| Average cost ($ per Mcfe) | $2.73 | $3.31 | $3.51 | $3.37 | $3.53 |
| Proved reserves (in Bcfe) (B) | 5,643 | 6,828 | 5,731 | 3,993 | 3,480 |
| Coal: | | | | | |
| Tons sold from continuing operations (in thousands)(C) | 29,234 | 32,419 | 28,776 | 27,612 | 32,090 |
| Tons produced from continuing operations (in thousands) | 29,286 | 32,218 | 28,476 | 27,178 | 31,721 |
| Average sales price of tons produced ($ per ton produced) | $56.66 | $63.03 | $69.34 | $77.75 | $90.10 |
| Average Cost of Goods Sold ($ per ton produced) | $43.64 | $46.91 | $50.78 | $53.98 | $51.88 |
| Recoverable coal reserves (tons in millions)(D) | 3,047 | 3,238 | 3,032 | 4,229 | 4,314 |
| Number of active mining complexes (at end of period) | 3 | 3 | 4 | 5 | 7 |

(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: 0.0 million tons, 0.2 million tons, 0.6 million tons, 0.5 million tons, and 0.6 million tons for the years ended December 31, 2015, 2014, 2013, 2012 and 2011, 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

2015 Highlights

- Record total gas production of 328.7 Bcfe in 2015, 39.5% higher than 2014.
- Record Marcellus Shale production of 168.7 Bcfe in 2015, 51.0% higher than 2014.
- On July 7, 2015, CNX Coal Resources LP (CNXC) closed its initial public offering. Additionally, Greenlight Capital entered into a common unit purchase agreement with CNXC pursuant to which Greenlight Capital agreed to purchase, and CNXC agreed to sell, 5,000,000 common units at a price per unit equal to $15.00, which equates to $75,000 in net proceeds. CNXC's general partner is CNX Coal Resources GP, a wholly owned subsidiary of CONSOL Energy. The underwriters of the IPO filing exercised an over-allotment option of 561,067 common units to the public at $15.00 per unit. The total net proceeds distributed to CONSOL Energy related to this transaction, along with CNXC entering into a new senior secured revolving credit facility, were $342,711.
- CONSOL now has 7 Utica wells online with two dry Utica PA wells. The Gaut 4I well in Westmoreland County, PA had an initial 24-hour flow test to sales of 61.4 MMcf per day at an average flowing casing pressure of 7,968 psi. The GH9 well in Greene County, PA had an initial 24-hour flow test of 61.9 MMcf per day at an average flowing casing pressure of 8,312 psi.
- Gas production costs continue to decline - for the year ended December 31, 2015, total gas production costs were $2.73 per Mcfe, a 17.5% decline from the prior year.

2016 Outlook:

- Our 2016 annual gas production is expected to be approximately 15% higher than 2015.
- Our 2016 E&P capital investment is expected to be between $205 - $325 million.
- Our 2016 coal production is expected to be between 27.0 - 32.0 million tons.
- Our 2016 coal and other capital investment is expected to be between $170 - $190 million.

Results of Operations: Year Ended December 31, 2015 Compared with the Year Ended December 31, 2014
Net (Loss) Income Attributable to CONSOL Energy Shareholders
CONSOL Energy reported a net loss attributable to CONSOL Energy shareholders of $375 million, or a loss of $1.64 per diluted share, for the year ended December 31, 2015, compared to net income attributable to CONSOL Energy shareholders of $163 million, or income of $0.70 per diluted share, for the year ended December 31, 2014.

CONSOL Energy consists of two principal business divisions: Exploration and Production (E&P) and Coal. The total E&P division includes four segments: Marcellus, Utica, Coalbed Methane (CBM) and Other Gas. The Coal division includes three segments: Pennsylvania (PA) operations, Virginia (VA) operations and Other Coal.

The total E&P division contributed a loss before income tax of $679 million for the year ended December 31, 2015 compared to earnings before income tax of $190 million for the year ended December 31, 2014. Included in the net loss was a pre-tax loss of $829 million primarily related to the impairment of the carrying value of CONSOL Energy's shallow oil and natural gas assets due to the continuation of depressed NYMEX forward strip prices.

Total gas production was 328.7 Bcfe for the year ended December 31, 2015 compared to 235.7 Bcfe for the year ended December 31, 2014. 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) | 2015 | 2014 | Variance | Percent Change |
| LIQUIDS | | | | |
| NGLs: | | | | |
| Sales Volume (MMcfe) | 33,180 | 15,475 | 17,705 | 114.4 % |
| Sales Volume (Mbbls) | 5,530 | 2,579 | 2,951 | 114.4 % |
| Gross Price ($/Bbl) | $12.30 | $35.70 | $(23.40) | (65.5)% |
| Gross Revenue | $68,057 | $92,136 | $(24,079) | (26.1)% |
| | | | | |
| Oil: | | | | |
| Sales Volume (MMcfe) | 592 | 681 | (89) | (13.1)% |
| Sales Volume (Mbbls) | 99 | 114 | (15) | (13.2)% |
| Gross Price ($/Bbl) | $47.94 | $89.10 | $(41.16) | (46.2)% |
| Gross Revenue | $4,736 | $10,108 | $(5,372) | (53.1)% |
| | | | | |
| Condensate: | | | | |
| Sales Volume (MMcfe) | 7,598 | 3,298 | 4,300 | 130.4 % |
| Sales Volume (Mbbls) | 1,266 | 550 | 716 | 130.2 % |
| Gross Price ($/Bbl) | $26.52 | $66.96 | $(40.44) | (60.4)% |
| Gross Revenue | $33,586 | $36,808 | $(3,222) | (8.8)% |
| | | | | |
| GAS | | | | |
| Sales Volume (MMcf) | 287,287 | 216,260 | 71,027 | 32.8 % |
| Sales Price ($/Mcf) | $2.17 | $4.02 | $(1.85) | (46.0)% |
| Gross Revenue | $622,080 | $868,329 | $(246,249) | (28.4)% |
| | | | | |
| Hedging Impact ($/Mcf) | $0.68 | $0.11 | $0.57 | 518.2 % |
| Gain on Commodity Derivative Instruments - Cash Settlement | $196,348 | $23,193 | $173,155 | 746.6 % |

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The average sales price, including the effects of derivative instruments, and average costs for all active gas operations were as follows:

| | For the Years Ended December 31, | | | |
|---|---|---|---|---|
| | 2015 | 2014 | Variance | Percent Change |
| Average Sales Price (per Mcfe) | $2.81 | $4.37 | $(1.56) | (35.7)% |
| Average Costs (per Mcfe) | 2.73 | 3.31 | (0.58) | (17.5)% |
| Margin | $0.08 | $1.06 | $(0.98) | (92.5)% |

Total E&P division outside sales revenues were $728 million for the year ended December 31, 2015 compared to $1,008 million for the year ended December 31, 2014. The decrease was primarily due to the the 35.7% decrease in the average sales price per Mcfe offset, in part, by the 39.5% increase in total volumes sold. The decrease in average sales price was the result of the overall decrease in general market prices. The decrease in general market prices was offset, in part, by various gas swap transactions that occurred throughout both periods.

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

- The improvement in unit costs is primarily due to the shift to lower cost Marcellus and Utica Shale production and the 39.5% increase in total volumes sold in the period-to-period comparison. Marcellus production made up 51.3% of natural gas and liquid sales volumes in the year ended December 31, 2015 compared to 47.4% in the year ended December 31, 2014. Utica production made up 17.1% of natural gas and liquid sales volumes in the year ended December 31, 2015 compared to 7.1% in the year ended December 31, 2014.
- Depreciation, depletion and amortization decreased on a unit basis primarily due to the adjustment to our shallow oil and gas rates following impairment in the carrying value that was recognized in the second quarter of 2015, as well as the increase in sales volumes from our lower cost Marcellus and Utica production. The decrease was offset, in part, by an increase in total dollars as production continued to grow.
- Lifting costs also decreased on a unit basis in the period-to-period comparison due to the overall increase in gas sales volumes. The decrease in unit costs was partially offset by an increase in repairs and maintenance, salt water disposal, and contractual services related to well tending.
- Direct administrative costs decreased on a unit basis primarily due to ongoing cost reduction efforts, the Company reorganization that occurred in the 2015 period, as well as the increase in gas sales volumes.

The total Coal division contributed $500 million of earnings before income tax for the year ended December 31, 2015 compared to $409 million for the year ended December 31, 2014. The total Coal division sold 29.2 million tons of coal produced from CONSOL Energy mines for the year ended December 31, 2015, compared to 32.4 million tons for the year ended December 31, 2014.

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, | | | |
|---|---|---|---|---|
| | 2015 | 2014 | Variance | Percent Change |
| Average Sales Price per ton sold | $56.66 | $63.03 | $(6.37) | (10.1)% |
| Average Costs of Goods Sold per ton | 43.64 | 46.91 | (3.27) | (7.0)% |
| Margin | $13.02 | $16.12 | $(3.10) | (19.2)% |

The lower average sales price per ton sold reflects the continuing decrease in the global metallurgical and domestic thermal coal markets and the oversupply of coal used in steelmaking and electricity generation. The Coal division priced 9.1 million tons on the export market for the year ended December 31, 2015 compared to 6.4 million tons for the year ended December 31, 2014. All other tons were sold on the domestic market.

Changes in the average cost of goods sold per ton were primarily attributable to the decrease in operating shifts at our mines. The Buchanan Mine went from three operating shifts to two operating shifts beginning in May 2014 and employed other cost cutting measures due to depressed market conditions. PA Operations also reduced their workforce and improved operational efficiencies in order to preserve margins. Also contributing to the decrease was the effect of the Pension and OPEB plan modifications in September 2014 for active employees, as well as a reduction in Pennsylvania stream subsidence expense. Refer to the discussion of total Company long-term liabilities for more information on the effect of the Pension and OPEB plan modifications.

The Other division includes other business activities not assigned to the E&P or Coal division, income taxes, and industrial supplies activity in the prior period (this subsidiary was sold in December 2014). The Other division had a net loss of $185 million for the year ended December 31, 2015 compared to a net loss of $430 million for the year ended December 31, 2014.
General and Administrative (G&A) costs are allocated between divisions (E&P, Coal and Other) based primarily on percentage of total revenue and percentage of total projected capital expenditures. Upon execution of the CNX Coal Resources LP (CNXC) initial public offering (IPO), CNXC entered into a service arrangement with CONSOL Energy to provide certain general and administrative services. These services are paid monthly based on an agreed upon fixed fee that is reset annually. See Note 27 - Related Party Transactions of the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.

G&A costs are excluded from the E&P and Coal unit costs above. Total Company G&A costs were $84 million for year ended December 31, 2015 compared to $110 million for the year ended December 31, 2014. G&A costs decreased due to the following items:

| | For the Years Ended December 31, | | | |
|---|---|---|---|---|
| (in millions) | 2015 | 2014 | Variance | Percent Change |
| Contributions | $3 | $12 | $(9) | (75.0)% |
| Consulting and Professional Services | 22 | 29 | (7) | (24.1)% |
| Employee Wages and Related Expenses | 38 | 45 | (7) | (15.6)% |
| Advertising and Promotion | 7 | 7 | — | —% |
| Miscellaneous | 14 | 17 | (3) | (17.6)% |
| Total Company General and Administrative Expense | $84 | $110 | $(26) | (23.6)% |

- Contributions decreased $9 million primarily due to a charitable contribution of $6 million to the Boy Scouts of America that was recorded during the year ended December 31, 2014. The remaining $3 million decrease is due to various transactions that occurred throughout both periods, none of which were individually material, including a general decrease in prepaid trade association dues during the year ended December 31, 2015.
- Consulting and professional services decreased $7 million due to various transactions that occurred throughout both periods, none of which were individually material, including a general decrease in legal expenses during the year ended December 31, 2015.
- Employee wages and related expenses decreased $7 million due to the Company reorganization that occurred in the year ended December 31, 2015.
- Advertising and promotion expenses remained consistent in the period-to-period comparison.
- Miscellaneous costs decreased $3 million due to various transactions that occurred throughout both periods, none of which were individually material.

Total Company long-term liabilities, such as Other Post-Employment Benefits (OPEB), the salary retirement plan, workers' compensation, Coal Workers' Pneumoconiosis (CWP), and long-term disability are actuarially calculated for the Company as a whole. In general, the expenses are then allocated to operational units based upon criteria specific to each liability. The allocation of OPEB and Pension expense in relation to the Coal division changed in 2015 to a methodology more in-line with the structural changes the company has been making. The amounts are also no longer included in unit costs because the majority of the covered employees are no longer active employees. Total CONSOL Energy expense related to our actuarial liabilities was income of $161 million for the year ended December 31, 2015 compared to expense of $96 million for the year ended December 31, 2014. The decrease of $257 million to total

Company expense was primarily due to modifications made to the OPEB and Pension plans in September 2014 and May 2015 coupled with a decrease to the pension settlement expense of $10 million. Pension settlement expense is required when lump sum distributions for a plan year exceed the total of the service and interest cost for the plan year. Not included in the 2014 long-term liability expense totals discussed above is $46 million of expense for cash payments made to active employees in the fourth quarter of 2014. in See Note 16—Pension and Other Postretirement Benefit Plans and Note 17—Coal Workers' Pneumoconiosis (CWP) and Workers' Compensation in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional details related to the total Company expense decrease.

TOTAL E&P DIVISION ANALYSIS for the year ended December 31, 2015 compared to the year ended December 31, 2014:

The E&P division had a loss before income tax of $679 million for the year ended December 31, 2015 compared to earnings before income tax of $190 million for the year ended December 31, 2014. Variances by individual E&P segment are discussed below.

| | For the Year Ended December 31, 2015 | | | | | Difference to Year Ended December 31, 2014 | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Marcellus | Utica | CBM | Other Gas | Total Gas | Marcellus | Utica | CBM | Other Gas | Total Gas |
| Sales: | | | | | | | | | | |
| Produced | $373 | $92 | $201 | $61 | $727 | $(85) | $5 | $(139) | $(59) | $(278) |
| Related Party | — | — | 1 | — | 1 | — | — | (2) | — | (2) |
| Total Outside Sales | 373 | 92 | 202 | 61 | 728 | (85) | 5 | (141) | (59) | (280) |
| Gain on Commodity Derivative Instruments | 98 | 6 | 67 | 222 | 393 | 83 | 5 | 63 | 219 | 370 |
| Production Royalty Interest | — | — | — | 45 | 45 | — | — | — | (37) | (37) |
| Purchased Gas | — | — | — | 14 | 14 | — | — | — | 5 | 5 |
| Miscellaneous Other Income | — | — | — | 66 | 66 | — | — | — | (1) | (1) |
| Gain on Sale of Assets | — | — | — | 13 | 13 | — | — | — | (33) | (33) |
| Total Revenue and Other Income | 471 | 98 | 269 | 421 | 1,259 | (2) | 10 | (78) | 94 | 24 |
| Lifting | 32 | 19 | 29 | 19 | 99 | 6 | 3 | (6) | (13) | (10) |
| Ad Valorem, Severance, and Other Taxes | 17 | 2 | 7 | 4 | 30 | — | 1 | (5) | (5) | (9) |
| Transportation, Gathering and Compression | 200 | 34 | 94 | 28 | 356 | 90 | 27 | (14) | (5) | 98 |
| Direct Administrative and Selling | 26 | 6 | 8 | 6 | 46 | (10) | 2 | (2) | 1 | (9) |
| Depreciation, Depletion and Amortization | 160 | 59 | 85 | 66 | 370 | 28 | 40 | (5) | (17) | 46 |
| General & Administration | — | — | — | 54 | 54 | — | — | — | (10) | (10) |
| Production Royalty Interest | — | — | — | 36 | 36 | — | — | — | (34) | (34) |
| Purchased Gas | — | — | — | 11 | 11 | — | — | — | 4 | 4 |
| Exploration and Other Costs | — | — | — | 10 | 10 | — | — | — | (13) | (13) |
| Other Corporate Expenses | — | — | — | 920 | 920 | — | — | — | 833 | 833 |
| Total Exploration and Production Costs | 435 | 120 | 223 | 1,154 | 1,932 | 114 | 73 | (32) | 741 | 896 |
| Interest Expense | — | — | — | 6 | 6 | — | — | — | (3) | (3) |
| Total E&P Division Costs | 435 | 120 | 223 | 1,160 | 1,938 | 114 | 73 | (32) | 738 | 893 |
| Earnings (Loss) Before Income Tax | $36 | $(22) | $46 | $(739) | $(679) | $(116) | $(63) | $(46) | $(644) | $(869) |

MARCELLUS GAS SEGMENT

The Marcellus segment had earnings before income tax of $36 million for the year ended December 31, 2015 compared to earnings before income tax of $152 million for the year ended December 31, 2014.

| | For the Years Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2015 | 2014 | Variance | Percent Change | |
| Marcellus Gas Sales Volumes (Bcf) | 145.8 | 99.4 | 46.4 | 46.7 | % |
| NGLs Sales Volumes (Bcfe)* | 19.0 | 10.9 | 8.1 | 74.3 | % |
| Condensate Sales Volumes (Bcfe)* | 3.9 | 1.4 | 2.5 | 178.6 | % |
| Total Marcellus Gas Sales Volumes (Bcfe)* | 168.7 | 111.7 | 57.0 | 51.0 | % |
| | | | | | |
| Average Sales Price - Gas (Mcf) | $2.09 | $3.83 | $(1.74 ) | (45.4 | )% |
| Gain on Commodity Derivative Instruments - Cash Settlement- Gas (Mcf) | $0.68 | $0.15 | $0.53 | 353.3 | % |
| Average Sales Price - NGLs (Mcfe)* | $2.54 | $5.77 | $(3.23 ) | (56.0 | )% |
| Average Sales Price - Condensate (Mcfe)* | $5.01 | $10.47 | $(5.46 ) | (52.1 | )% |
| | | | | | |
| Total Average Marcellus Sales Price (per Mcfe) | $2.79 | $4.24 | $(1.45 ) | (34.2 | )% |
| Average Marcellus Lifting Costs (per Mcfe) | 0.19 | 0.23 | (0.04 ) | (17.4 | )% |
| Average Marcellus Ad Valorem, Severance, and Other Taxes (per Mcfe) | 0.10 | 0.16 | (0.06 ) | (37.5 | )% |
| Average Marcellus Transportation, Gathering, and Compression Costs (per Mcfe) | 1.18 | 0.98 | 0.20 | 20.4 | % |
| Average Marcellus Direct Administrative and Selling Costs (per Mcfe) | 0.15 | 0.32 | (0.17 ) | (53.1 | )% |
| Average Marcellus Depreciation, Depletion and Amortization Costs (per Mcfe) | 0.95 | 1.19 | (0.24 ) | (20.2 | )% |
| Total Average Marcellus Costs (per Mcfe) | $2.57 | $2.88 | $(0.31 ) | (10.8 | )% |
| Average Margin for Marcellus (per Mcfe) | $0.22 | $1.36 | $(1.14 ) | (83.8 | )% |

* 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 outside sales revenues were $373 million for the year ended December 31, 2015 compared to $458 million for the year ended December 31, 2014. The $85 million decrease was primarily due to a 45.4% decrease in the total average sales price in the period-to-period comparison, partially offset by a 51.0% increase in total gas sales volumes. The increase in gas sales volumes is primarily due to additional wells coming on-line in the current period.

The decrease in Marcellus total average sales price was primarily the result of the $1.74 per Mcf decrease in gas market prices, along with a $0.15 per Mcfe decrease in the uplift from natural gas liquids and condensate sales volumes when excluding the impact of hedging. The decrease was offset, in part, by a $0.53 per Mcf increase resulting from various transactions from our hedging program. These financial hedges represented approximately 90.3 Bcf of our produced Marcellus gas sales volumes for the year ended December 31, 2015 at an average gain of $1.09 per Mcf. For the year ended December 31, 2014, these financial hedges represented 70.4 Bcf at an average gain of $0.21 per Mcf.

Total costs for the Marcellus segment were $435 million for the year ended December 31, 2015 compared to $321 million for the year ended December 31, 2014. The increase in total dollars and decrease in unit costs for the

Marcellus segment are due to the following items:

•Marcellus lifting costs were $32 million for the year ended December 31, 2015 compared to $26 million for the year ended December 31, 2014. The increase in total dollars was primarily due to the increase in production which resulted in increased salt water disposal costs, increased repair and maintenance costs, and increased contractual services related to well tending. The decrease in unit costs was primarily due to the 51.0% increase in total sales volumes.

•Marcellus ad valorem, severance and other taxes were $17 million for the year ended December 31, 2015 and 2014. The decrease in unit costs was primarily due to the 51.0% increase in total sales volumes offset, in part, by the decrease in average sales price.

•Marcellus transportation, gathering, and compression costs were $200 million for the year ended December 31, 2015 compared to $110 million for the year ended December 31, 2014. The $90 million increase in total dollars was primarily related to an increase in the CONE gathering fee due to the increase in gas sales volumes (See Note 27 - Related Party Transactions of the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information), an increase in processing fees associated with natural gas liquids primarily due to the 74.3% increase in NGLs sales volumes, and an increase in utilized firm transportation expense. The increase in unit costs was due to the overall increase in total dollars.

•Marcellus direct administrative and selling costs were $26 million for the year ended December 31, 2015 compared to $36 million for the year ended December 31, 2014. Direct administrative and selling costs attributable to the total E&P division are allocated to the individual E&P segments based on a combination of capital, production and employee counts. The decrease in total dollars was primarily due to ongoing cost reduction efforts and the Company reorganization that occurred in the 2015 period. Unit costs were positively impacted by the increase in gas sales volumes.

•Depreciation, depletion and amortization costs attributable to the Marcellus segment were $160 million for the year ended December 31, 2015 compared to $132 million for the year ended December 31, 2014. These amounts included depreciation on a per unit basis of $0.94 per Mcf and $1.16 per Mcf, respectively. The remaining depreciation, depletion and amortization costs were either recorded on a straight-line basis or related to gas well accretion.

UTICA GAS SEGMENT

The Utica segment had a loss before income tax of $22 million for the year ended December 31, 2015 compared to earnings before income tax of $41 million for the year ended December 31, 2014.

| | For the Years Ended December 31, | | | |
|---|---|---|---|---|
| | 2015 | 2014 | Variance | Percent Change |
| Utica Gas Sales Volumes (Bcf) | 38.3 | 10.2 | 28.1 | 275.5 % |
| NGL Sales Volumes (Bcfe)* | 14.1 | 4.6 | 9.5 | 206.5 % |
| Oil Sales Volumes (Bcfe)* | 0.1 | — | 0.1 | 100.0 % |
| Condensate Sales Volumes (Bcfe)* | 3.7 | 1.9 | 1.8 | 94.7 % |
| Total Utica Sales Volumes (Bcfe)* | 56.2 | 16.7 | 39.5 | 236.5 % |
| | | | | |
| Average Sales Price - Gas (Mcf) | $1.52 | $3.46 | $(1.94) | (56.1)% |
| Gain on Commodity Derivative Instruments - Cash Settlement- Gas (Mcf) | $0.17 | $0.12 | $0.05 | 41.7 % |
| Average Sales Price - NGL (Mcfe)* | $1.39 | $6.39 | $(5.00) | (78.2)% |
| Average Sales Price - Oil (Mcfe)* | $6.58 | $15.81 | $(9.23) | (58.4)% |
| Average Sales Price - Condensate (Mcfe)* | $3.79 | $11.69 | $(7.90) | (67.6)% |
| | | | | |
| Total Average Utica Sales Price (per Mcfe) | $1.75 | $5.27 | $(3.52) | (66.8)% |
| Average Utica Lifting Costs (per Mcfe) | 0.34 | 0.94 | (0.60) | (63.8)% |
| Average Utica Ad Valorem, Severance, and Other Taxes (per Mcfe) | 0.04 | 0.08 | (0.04) | (50.0)% |
| Average Utica Transportation, Gathering, and Compression Costs (per Mcfe) | 0.61 | 0.45 | 0.16 | 35.6 % |
| Average Utica Direct Administrative and Selling Costs (per Mcfe) | 0.11 | 0.24 | (0.13) | (54.2)% |
| Average Utica Depreciation, Depletion and Amortization Costs (per Mcfe) | 1.04 | 1.11 | (0.07) | (6.3)% |
| Total Average Utica Costs (per Mcfe) | $2.14 | $2.82 | $(0.68) | (24.1)% |

| | | | | |
|---|---|---|---|---|
| Average Margin for Utica (per Mcfe) | $(0.39 ) | $2.45 | $(2.84 ) | (115.9 )% |

*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 Utica segment outside sales revenues were $92 million for the year ended December 31, 2015 compared to $87 million for the year ended December 31, 2014. The increase was primarily due to the 236.5% increase in total volumes sold and was offset, in part, by the 66.8% decrease in the total average sales price. The 39.5 Bcfe increase in total volumes sold was primarily due to additional wells coming on-line in the current period.

The decrease in Utica total average sales price was primarily the result of a $1.94 per Mcf decrease in average market prices, offset in part by a $0.05 per Mcf increase resulting from various transactions from our hedging program. These economic hedges represented approximately 5.9 Bcf of our produced Utica gas sales volumes for the year ended December 31, 2015 at an average gain of $1.08 per Mcf. For the year ended December 31, 2014, these economic hedges represented approximately 3.5 Bcf at an average gain of $0.35 per Mcf.

Total costs for the Utica segment were $120 million for the year ended December 31, 2015 compared to $47 million for the year ended December 31, 2014. The increase in total dollars and decrease in unit costs for the Utica segment are due to the following items:

•Utica lifting costs were $19 million for the year ended December 31, 2015 compared to $16 million for the year ended December 31, 2014. The increase in total dollars was primarily due to the increase in production which resulted in increased repair and maintenance costs, as well as increased contractual services related to well tending. The decrease in unit costs was primarily due to the 236.5% increase in total sales volumes.

•Utica ad valorem, severance and other taxes were $2 million for the year ended December 31, 2015 compared to $1 million for the year ended December 31, 2014. The increase in total dollars was primarily due to an increase in severance tax expense caused by the increase in total sales volumes. Unit costs were positively impacted by both the increased sales volumes and the decreased average sales price.

•Utica transportation, gathering, and compression costs were $34 million for the year ended December 31, 2015 compared to $7 million for the year ended December 31, 2014. The $27 million increase in total dollars was primarily related to increased gathering and processing fees associated with the increased sales volumes. The increase in unit costs was due to the increase in total dollars and was offset, in part, by the increase in gas sales volumes.

•Utica direct administrative and selling costs were $6 million for the year ended December 31, 2015 compared to $4 million for the year ended December 31, 2014. Direct administrative and selling costs attributable to the total E&P division are allocated to the individual E&P segments based on a combination of capital, production, and employee counts. The increase in total dollars was primarily due to a larger portion of the total company expense being allocated to the Utica segment. Unit costs were positively impacted by the increase in gas sales volumes.

•Depreciation, depletion and amortization costs attributable to the Utica segment were $59 million for the year ended December 31, 2015 compared to $19 million for the year ended December 31, 2014. These amounts included depreciation on a per unit basis of $1.04 per Mcf and $1.09 per Mcf, respectively. The remaining depreciation, depletion and amortization costs were either recorded on a straight-line basis or related to gas well accretion.

COALBED METHANE (CBM) GAS SEGMENT

The CBM segment contributed $46 million to the total Company earnings before income tax for the year ended December 31, 2015 compared to $92 million for the year ended December 31, 2014.

| | For the Years Ended December 31, | | | |
|---|---|---|---|---|
| | 2015 | 2014 | Variance | Percent Change |
| CBM Gas Sales Volumes (Bcf) | 74.9 | 79.5 | (4.6) | (5.8)% |
| Average Sales Price - Gas (Mcf) | $2.70 | $4.32 | $(1.62) | (37.5)% |
| Gain on Commodity Derivative Instruments - Cash Settlement- Gas (Mcf) | $0.90 | $0.05 | $0.85 | 1,700.0% |
| Total Average CBM Sales Price (per Mcf) | $3.60 | $4.37 | $(0.77) | (17.6)% |
| Average CBM Lifting Costs (per Mcf) | 0.39 | 0.45 | (0.06) | (13.3)% |
| Average CBM Ad Valorem, Severance, and Other Taxes (per Mcf) | 0.10 | 0.15 | (0.05) | (33.3)% |
| Average CBM Transportation, Gathering, and Compression Costs (per Mcf) | 1.26 | 1.35 | (0.09) | (6.7)% |
| Average CBM Direct Administrative and Selling Costs (per Mcf) | 0.11 | 0.13 | (0.02) | (15.4)% |
| Average CBM Depreciation, Depletion and Amortization Costs (per Mcf) | 1.13 | 1.14 | (0.01) | (0.9)% |
| Total Average CBM Costs (per Mcf) | $2.99 | $3.22 | $(0.23) | (7.1)% |
| Average Margin for CBM (per Mcf) | $0.61 | $1.15 | $(0.54) | (47.0)% |

The CBM segment outside sales revenues were $202 million for the year ended December 31, 2015 compared to $343 million for the year ended December 31, 2014. The $141 million decrease was primarily due to a 37.5% decrease in the total average sales price per Mcf as well as a 5.8% decrease in total volumes sold. The decrease in volumes sold was primarily due to normal well declines without a corresponding offset of additional wells drilled.

The CBM total average sales price decreased $0.77 per Mcf due to a $1.62 per Mcf decrease in gas market prices. The decrease was offset, in part, by a $0.85 per Mcf increase due to various transactions from our hedging program. Financial hedges represented approximately 57.5 Bcf of our produced CBM gas sales volumes for the year ended December 31, 2015 at an average gain of $1.17 per Mcf. For the year ended December 31, 2014, these financial hedges represented 70.0 Bcf at an average gain of $0.06 per Mcf.

Total costs for the CBM segment were $223 million for the year ended December 31, 2015 compared to $255 million for the year ended December 31, 2014. The decrease in total dollars and decrease in unit costs for the CBM segment were due to the following items:

•CBM lifting costs were $29 million for the year ended December 31, 2015 compared to $35 million for the year ended December 31, 2014. The decrease in total dollars was primarily related to a decrease in contractual services related to well tending and a decrease in repairs and maintenance expense. The decrease in unit costs was due to the decrease in total dollars offset, in part, by the decrease in gas sales volumes.

•CBM ad valorem, severance and other taxes were $7 million for the year ended December 31, 2015 compared to $12 million for the year ended December 31, 2014. The decrease of $5 million was due to a decrease in severance tax expense resulting from the decrease in both gas sales volumes and average sales price. Unit costs were also positively impacted by the decrease in average sales price which was offset, in part, by the decrease in gas sales volumes.

•CBM transportation, gathering, and compression costs were $94 million for the year ended December 31, 2015 compared to $108 million for the year ended December 31, 2014. The $14 million decrease in total dollars was primarily related to a decrease in repairs and maintenance, a decrease in power, and a decrease in utilized firm transportation expense resulting from the decrease in sales volumes. Unit costs were also positively impacted by the decrease in total dollars, which was offset, in part, by the decrease in sales volumes.

•CBM direct administrative and selling costs were $8 million for the year ended December 31, 2015 compared to $10 million for the year ended December 31, 2014. The decrease in total dollars is primarily due to a smaller portion of the total company expense being allocated to the CBM segment along with the Company reorganization that occurred in the 2015 period.

Unit costs also decreased in the period-to-period comparison, primarily as a result of the decrease in total dollars, offset, in part, by the decrease in sales volumes.

•Depreciation, depletion and amortization costs attributable to the CBM segment were $85 million for the year ended December 31, 2015 compared to $90 million for the year ended December 31, 2014. These amounts included depreciation on a per unit basis of $0.73 per Mcf and $0.75 per Mcf, respectively. The remaining depreciation, depletion and amortization costs were either recorded on a straight-line basis or related to gas well accretion.

OTHER GAS SEGMENT

The Other Gas segment had a loss before income taxes of $739 million for the year ended December 31, 2015 compared to a loss before income tax of $95 million for the year ended December 31, 2014.

| | For the Years Ended December 31, | | | |
|---|---|---|---|---|
| | 2015 | 2014 | Variance | Percent Change |
| Other Gas Sales Volumes (Bcf) | 28.4 | 27.1 | 1.3 | 4.8 % |
| Oil Sales Volumes (Bcfe)* | 0.5 | 0.7 | (0.2 ) | (28.6 )% |
| Total Other Sales Volumes (Bcfe)* | 28.9 | 27.8 | 1.1 | 4.0 % |
| | | | | |
| Average Sales Price - Gas (Mcf) | $2.01 | $4.01 | $(2.00 ) | (49.9 )% |
| Gain on Commodity Derivative Instruments - Cash Settlement- Gas (Mcf) | $0.86 | $0.11 | $0.75 | 681.8 % |
| Average Sales Price - Oil (Mcfe)* | $8.15 | $14.81 | $(6.66 ) | (45.0 )% |
| | | | | |
| Total Average Other Sales Price (per Mcfe) | $2.97 | $4.39 | $(1.42 ) | (32.3 )% |
| Average Other Lifting Costs (per Mcfe) | 0.68 | 1.13 | (0.45 ) | (39.8 )% |
| Average Other Ad Valorem, Severance, and Other Taxes (per Mcfe) | 0.13 | 0.28 | (0.15 ) | (53.6 )% |
| Average Other Transportation, Gathering, and Compression Costs (per Mcfe) | 0.96 | 1.21 | (0.25 ) | (20.7 )% |
| Average Other Direct Administrative and Selling Costs (per Mcfe) | 0.22 | 0.19 | 0.03 | 15.8 % |
| Average Other Depreciation, Depletion and Amortization Costs (per Mcfe) | 2.12 | 2.86 | (0.74 ) | (25.9 )% |
| Total Average Other Costs (per Mcfe) | $4.11 | $5.67 | $(1.56 ) | (27.5 )% |
| Average Margin for Other (per Mcfe) | $(1.14 ) | $(1.28 ) | $0.14 | 10.9 % |

*Oil is 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 Other Gas segment includes activity not assigned to the Marcellus, Utica, or CBM segments. This segment also includes purchased gas activity, production royalty interest activity, exploration and other costs, unrealized gain on commodity derivative instruments, other corporate expenses, and miscellaneous operational activity not assigned to a specific E&P segment.

Other Gas sales volumes are primarily related to shallow oil and gas production as well as Upper Devonian Shale in Pennsylvania and West Virginia. Outside sales revenue from the other gas segment was approximately $61 million for the year ended December 31, 2015 compared to $120 million for the year ended December 31, 2014. The decrease in outside sales revenue primarily relates to the $1.42 per Mcfe decrease in total average sales price. Total costs related to these other sales were $123 million for the year ended December 31, 2015 compared to $162 million for the year ended December 31, 2014. The decrease was primarily due to a decrease in depreciation, depletion and amortization related to the adjustment to our shallow oil and gas rates after the impairment in the carrying value that was recognized in the second quarter of 2015.

Included in gain on commodity derivative instruments related to the Other Gas segment for the year ended December 31, 2015 is an unrealized gain of $197 million. The unrealized gain represents changes in the fair value of all of the Company's existing gas commodity hedges on a mark-to-market basis. The unrealized gain on commodity derivative instruments is a result of the December 31, 2014 de-designation of all derivative positions as cash flow hedges. Changes in fair value were recorded in Accumulated Other Comprehensive Income prior to de-designation. Production royalty interest gas sales represent the revenues related to the portion of production belonging to royalty interest owners sold by the CONSOL Energy E&P segment. Production royalty interest gas sales revenues were $45 million for the year ended December 31, 2015 compared to $82 million for the year ended December 31, 2014. 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 decrease.

| | For the Years Ended December 31, | | | |
|---|---|---|---|---|
| | 2015 | 2014 | Variance | Percent Change |
| Production Royalty Interest Sales Volumes (in billion cubic feet) | 23.9 | 19.9 | 4.0 | 20.1 % |
| Average Sales Price Per thousand cubic feet | $1.89 | $4.14 | $(2.25) | (54.3)% |

Purchased gas sales volumes represent volumes of gas sold at market prices that were purchased from third-party producers. Purchased gas sales revenues were $14 million for the year ended December 31, 2015 compared to $9 million for the year ended December 31, 2014. The period-to-period increase in purchased gas sales revenue was primarily due to the increase in purchased gas sales volumes, partially offset by the decrease in average sales price.

| | For the Years Ended December 31, | | | |
|---|---|---|---|---|
| | 2015 | 2014 | Variance | Percent Change |
| Purchased Gas Sales Volumes (in billion cubic feet) | 6.8 | 1.9 | 4.9 | 257.9 % |
| Average Sales Price Per thousand cubic feet | $2.14 | $4.65 | $(2.51) | (54.0)% |

Miscellaneous other income was $66 million for the year ended December 31, 2015 compared to $67 million for the year ended December 31, 2014. The $1 million decrease was primarily due to the following items:

| | For the Years Ended December 31, | | | |
|---|---|---|---|---|
| (in millions) | 2015 | 2014 | Variance | Percent Change |
| Gathering Revenue | $13 | $30 | $(17) | (56.7)% |
| Equity in Earnings of Affiliates | 47 | 32 | 15 | 46.9 % |
| Other | 6 | 5 | 1 | 20.0 % |
| Total Miscellaneous Other Income | $66 | $67 | $(1) | (1.5)% |

- Gathering revenue decreased $17 million primarily due to a decrease in revenue related to certain gathering arrangements.
- Equity in Earnings of Affiliates increased $15 million primarily due to an increase in earnings from CONE Midstream Partners LP and CONE Gathering LLC. See Note 27 - Related Party Transactions in the Notes to Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.
- Other increased $1 million due to various transactions that occurred throughout both periods, none of which were individually material.

Gain on sale of assets was $13 million for the year ended December 31, 2015 compared to $46 million for the year ended December 31, 2014. The $33 million decrease was primarily due to the sale of Utica rights in Marshall County, WV to Noble Energy, which closed in December 2014 and resulted in a pre-tax gain of $25 million. The remaining decrease 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 E&P segment based on percentage of total revenue and percentage of total projected capital expenditures. Costs were $54 million for the year ended December 31, 2015 and $64 million for the year ended December 31, 2014. Refer to the discussion of total company general and administrative costs contained in the section "Net (Loss) Income Attributable to CONSOL Energy Shareholders" of this annual 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 E&P division. Production royalty interest gas costs were $36 million for the year ended

December 31, 2015 compared to $70 million for the year ended December 31, 2014. 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, | | | |
|---|---|---|---|---|
| | 2015 | 2014 | Variance | Percent Change |
| Production Royalty Interest Sales Volumes (in billion cubic feet) | 23.9 | 19.9 | 4.0 | 20.1 % |
| Average Cost Per thousand cubic feet sold | $1.50 | $3.51 | $(2.01) | (57.3)% |

Purchased gas volumes represent volumes of gas purchased from third-party producers that CONSOL Energy sells. The lower average cost per thousand cubic feet is due to overall price changes and contractual differences among customers in the period-to-period comparison. Purchased gas costs were $11 million for the year ended December 31, 2015 compared to $7 million for the year ended December 31, 2014.

| | For the Years Ended December 31, | | | |
|---|---|---|---|---|
| | 2015 | 2014 | Variance | Percent Change |
| Purchased Gas Volumes (in billion cubic feet) | 6.8 | 1.9 | 4.9 | 257.9 % |
| Average Cost Per thousand cubic feet sold | $1.59 | $3.75 | $(2.16) | (57.6)% |

Exploration and other costs were $10 million for the year ended December 31, 2015 compared to $23 million for the year ended December 31, 2014. The $13 million decrease in costs is primarily related to the following items:

| | For the Years Ended December 31, | | | |
|---|---|---|---|---|
| (in millions) | 2015 | 2014 | Variance | Percent Change |
| Lease Expiration Costs | $4 | $9 | $(5) | (55.6)% |
| Seismic Activity | — | 5 | (5) | (100.0)% |
| Land Rentals | 5 | 5 | — | — % |
| Other | 1 | 4 | (3) | (75.0)% |
| Total Exploration and Other Costs | $10 | $23 | $(13) | (56.5)% |

- Lease expiration costs decreased by $5 million in the period-to-period comparison, primarily due to a decreased number of leases expiring in the year ended December 31, 2015 as compared to the year ended December 31, 2014.
- Seismic activity decreased by $5 million in the period-to-period comparison, primarily due to cost reduction efforts in the 2015 period.
- Land rental costs remained consistent in the period-to-period comparison.
- The remaining $3 million decrease related to various transactions that occurred throughout both periods, none of which were individually material.

Other corporate expenses were $920 million for the year ended December 31, 2015 compared to $87 million for the year ended December 31, 2014. The $833 million increase in the period-to-period comparison was made up of the following items:

| | For the Years Ended December 31, | | | |
|---|---|---|---|---|
| (in millions) | 2015 | 2014 | Variance | Percent Change |
| Impairment of Exploration and Production Properties | $829 | $— | $829 | 100.0 % |
| Idle Rig Expense | 19 | — | 19 | 100.0 % |
| Severance Expense | 5 | — | 5 | 100.0 % |
| Stock-Based Compensation | 14 | 17 | (3) | (17.6)% |
| Bank Fees | — | 4 | (4) | (100.0)% |
| Unutilized Firm Transportation and Processing Fees | 33 | 38 | (5) | (13.2)% |
| Short-Term Incentive Compensation | 10 | 23 | (13) | (56.5)% |

| | | | | | |
|---|---|---|---|---|---|
| Other | 10 | 5 | 5 | 100.0 | % |
| Total Other Corporate Expenses | $920 | $87 | $833 | 957.5 | % |

- Impairment of exploration and production properties primarily related to the write down of the Company's shallow oil and gas asset values in the second quarter of 2015 including impairments to unproved property. See Note 1 - Significant Accounting Policies in Item 8 of this Form 10-K for additional information.

- Idle rig fees are related to the temporary idling of some of the Company's natural gas rigs during the year ended December 31, 2015 in response to market conditions. There were no idle rig fees for the year ended December 31, 2014.
- Severance expense was a result of the Company reorganization that occurred in the 2015 period. There was no such expense in the 2014 period.
- Stock-based compensation decreased $3 million in the period-to-period comparison primarily due to less accelerated expense for retiree eligible employees under our current plan.
- Bank fees decreased $4 million due to the termination of the CNX Gas Senior Secured Credit Agreement on June 18, 2014.
- Unutilized firm transportation costs represent pipeline transportation capacity the E&P segment has obtained to enable gas production to flow uninterrupted as sales volumes increase, as well as additional processing capacity for natural gas liquids. Unutilized firm transportation and processing fees decreased $5 million in the period-to-period comparison due to an increase in the utilization of the capacity.
- Short-term incentive compensation expense decreased in the period-to-period comparison due to a reduction in payouts in the current period.
- Other corporate related expenses increased $5 million due to various transactions that occurred throughout both periods, none of which were individually material.

Interest expense related to the E&P division was $6 million for the year ended December 31, 2015 compared to $9 million for the year ended December 31, 2014. Interest expense was incurred by the Other gas segment on interest allocated to the E&P division under CONSOL Energy's credit facility.

TOTAL COAL DIVISION ANALYSIS for the year ended December 31, 2015 compared to the year ended December 31, 2014:

The Coal division had earnings before income tax of $500 million in the year ended December 31, 2015 compared to earnings before income tax of $409 million in the year ended December 31, 2014. Variances by individual Coal segment are discussed below.

| | For the Year Ended December 31, 2015 | | | | Difference to Year Ended December 31, 2014 | | | |
|---|---|---|---|---|---|---|---|---|
| | Pennsylvania Operations | Virginia Operations | Other Coal | Total Coal | Pennsylvania Operations | Virginia Operations | Other Coal | Total Coal |
| Sales: | | | | | | | | |
| Produced Coal | $1,289 | $ 248 | $119 | $1,656 | $(328) | $ (49) | $(10) | $(387) |
| Purchased Coal | — | — | 2 | 2 | — | — | (7) | (7) |
| Total Outside Sales | 1,289 | 248 | 121 | 1,658 | (328) | (49) | (17) | (394) |
| Other Outside Sales | — | — | 31 | 31 | — | — | (10) | (10) |
| Freight Revenue | 15 | 2 | 9 | 26 | (2) | 1 | (1) | (2) |
| Miscellaneous Other Income | 4 | — | 74 | 78 | (34) | — | (27) | (61) |
| Gain on Sale of Assets | — | — | 61 | 61 | (1) | — | 33 | 32 |
| Total Revenue and Other Income | 1,308 | 250 | 296 | 1,854 | (365) | (48) | (22) | (435) |
| Operating Costs and Expenses: | | | | | | | | |
| Operating Costs | 715 | 149 | 92 | 956 | (161) | (38) | (14) | (213) |
| Direct Administrative and Selling | 25 | 5 | 2 | 32 | (6) | (1) | (1) | (8) |
| Total Royalty/Production Taxes | 51 | 14 | 11 | 76 | (20) | (4) | 1 | (23) |
| Depreciation, Depletion and Amortization | 167 | 36 | 8 | 211 | 2 | (4) | 1 | (1) |
| Total Operating Costs and Expenses | 958 | 204 | 113 | 1,275 | (185) | (47) | (13) | (245) |
| Other Costs and Expenses: | | | | | | | | |
| Other Costs | (122) | (57) | 85 | (94) | (130) | (63) | (56) | (249) |
| Direct Administrative | — | — | 1 | 1 | (1) | — | (2) | (3) |
| Total Royalty/Production Taxes | — | — | 3 | 3 | — | — | 1 | 1 |
| Depreciation, Depletion and Amortization | 10 | 14 | 44 | 68 | 2 | 6 | (8) | — |
| Total Other Costs and Expenses | (112) | (43) | 133 | (22) | (129) | (57) | (65) | (251) |
| Freight Expense | 15 | 2 | 9 | 26 | (2) | 1 | (1) | (2) |
| General and Administrative Expense | 15 | 4 | 11 | 30 | (11) | (5) | 1 | (15) |
| Other Corporate Expenses | 22 | 10 | 8 | 40 | (17) | 1 | 1 | (15) |
| Related Party | — | 2 | — | 2 | — | (1) | — | (1) |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Total Coal Costs | 898 | 179 | 274 | 1,351 | (344) | (108) | (77) | (529) |
| Interest Expense | 3 | — | — | 3 | 3 | — | — | 3 |
| Total Coal Division Expense | 901 | 179 | 274 | 1,354 | (341) | (108) | (77) | (526) |
| Earnings (Loss) Before Income Taxes | $407 | $71 | $22 | $500 | $(24) | $60 | $55 | $91 |

PENNSYLVANIA (PA) OPERATIONS COAL SEGMENT

The PA Operations coal segment's principal activities are the mining, preparation and marketing of thermal coal to power generators. The segment also includes general and administrative activities as well as various other activities assigned to the PA Operations coal segment but not allocated to each individual mine and, therefore, are not included in unit cost presentation. For the years ended December 31, 2015 and 2014, the segment included the following mines: Bailey Mine, Enlow Fork Mine, Harvey Mine and the corresponding preparation plant facilities.

The PA Operations coal segment had earnings before income tax of $407 million for the year ended December 31, 2015, compared to earnings before income tax of $431 million for the year ended December 31, 2014. The PA Operations coal revenue and cost components on a per unit basis for these periods are as follows:

| | For the Years Ended December 31, | | | |
|---|---|---|---|---|
| | 2015 | 2014 | Variance | Percent Change |
| Company Produced PA Operations Tons Sold (in millions) | 22.9 | 26.1 | (3.2) | (12.3%) |
| Average Sales Price Per PA Operations Ton Sold | $56.36 | $61.88 | $(5.52) | (8.9%) |
| | | | | |
| Total Operating Costs Per Ton Sold | $31.24 | $33.50 | $(2.26) | (6.7%) |
| Total Direct Administrative and Selling Costs Per Ton Sold | 1.11 | 1.20 | (0.09) | (7.5%) |
| Total Royalty/Production Taxes Per Ton Sold | 2.25 | 2.71 | (0.46) | (17.0%) |
| Total Depreciation, Depletion and Amortization Costs Per Ton Sold | 7.31 | 6.34 | 0.97 | 15.3% |
| Total Costs Per PA Operations Ton Sold | $41.91 | $43.75 | $(1.84) | (4.2%) |
| Average Margin Per PA Operations Ton Sold | $14.45 | $18.13 | $(3.68) | (20.3%) |

Coal Sales

PA Operations produced coal outside sales revenues were $1,289 million for the year ended December 31, 2015, compared to $1,617 million for the year ended December 31, 2014. The $328 million decrease was attributable to a 3.2 million decrease in tons sold and a $5.52 per ton lower average sales price. The lower sales volumes and average coal sales price per PA Operations ton sold were primarily the result of the continued decline in domestic and global thermal coal markets. Due to the weak domestic thermal spot market, 6 million tons were sold on the export market for the year ended December 31, 2015 compared to 3 million tons for the year ended December 31, 2014.

Freight Revenue

Freight revenue is the amount billed to customers for transportation costs incurred. This revenue is based on the weight of coal shipped, negotiated freight rates and method of transportation, primarily rail, used by the customers to which CONSOL Energy contractually provides transportation services. Freight revenue is completely offset in freight expense. Freight revenue was $15 million for the year ended December 31, 2015, compared to $17 million for the year ended December 31, 2014. The $2 million decrease in freight revenue was due to decreased shipments where CONSOL Energy contractually provides transportation services.

Miscellaneous Other Income

Miscellaneous other income was $4 million for the year ended December 31, 2015, compared to $38 million for the year ended December 31, 2014. Approximately $30 million of the decrease related to a coal customer contract buyout in the prior period. The remaining $4 million decrease was a result of various transactions that occurred during both periods, none of which were individually material.

Cost of Coal Sold

Cost of coal sold is comprised of operating and other production costs related to produced tons sold, along with changes in coal inventory, both in volumes and carrying values. The cost of coal sold per ton includes items such as direct operating costs, royalty and production taxes, direct administration and selling expense, and depreciation, depletion, and amortization costs. Total cost of coal sold for PA Operations was $958 million for the year ended

December 31, 2015, or $185 million lower than the $1,143 million for the year ended December 31, 2014. Total costs per PA Operations ton sold were $41.91 per ton in the year ended December 31, 2015, compared to $43.75 per ton in the year ended December 31, 2014. The decrease in the cost of coal sold was driven by improved operational efficiencies, better geological conditions, a reduced workforce, a decrease in stream subsidence expense and other ongoing cost reduction efforts. In order to preserve margins, PA Operations moved to a four-day work week in May 2015, compared to a normal five-day per week schedule. The decrease in unit costs was primarily the result of the Pension and OPEB plan modifications for active employees in September 2014. Refer to the discussion of total Company long-term liabilities contained in the section "Net (Loss) Income Attributable to CONSOL Energy Shareholders" of this annual report for a detailed cost explanation.

Other Costs And Expenses

Other costs include various costs and expenses that are assigned to the PA Operations coal segment but not allocated to each individual mine and, therefore, are not included in unit costs. Other costs resulted in income of $122 million for the year ended December 31, 2015 compared to expense of $8 million for the year ended December 31, 2014. The decrease of $130 million was due to the following:

| | For the Years Ended December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | Variance |
| OPEB Plan Changes | $(129) | $— | $(129) |
| Coal Reserve Holding Costs | 5 | 3 | 2 |
| Other | 2 | 5 | (3) |
| Other Costs | $(122) | $8 | $(130) |

- Income of $129 million related to OPEB plan changes was the result of modifications made to the OPEB plan in May 2015 for retired employees. Refer to the discussion of total Company long-term liabilities contained in the section "Net (Loss) Income Attributable to CONSOL Energy Shareholders" of this annual report for more information.
- Coal Reserve Holding Costs increased $2 million in the period-to-period comparison due to various transactions that occurred throughout both periods, none of which were individually material.
- Other decreased $3 million in the period-to-period comparison due to various transactions that occurred throughout both periods, none of which were individually material.

Direct administrative expense consists primarily of labor and benefits and consulting expenses that relate to coal terminal operations and idle mine locations. Direct administrative expense decreased $1 million in the period-to-period comparison primarily due to ongoing cost reduction efforts, as well as the Company reorganization that occurred in the 2015 period.

Depreciation, depletion and amortization increased $2 million, primarily as a result of additional assets placed in service in the period-to-period comparison.

Freight Expense

Freight expense is based on weight of coal shipped, negotiated freight rates and method of transportation, primarily rail, used by the customers to which CONSOL Energy contractually provides transportation services. Freight revenue is the amount billed to customers for transportation costs incurred. Freight expense is offset by freight revenue. Freight expense was $15 million for the year ended December 31, 2015, compared to $17 million for the year ended December 31, 2014. The $2 million decrease in freight expense was due to decreased shipments where CONSOL Energy contractually provides transportation services.

General and Administrative Expense

General and administrative costs are allocated to each coal segment based upon the level of operating activity of the segment's underlying business units. Upon execution of the CNXC IPO, CNXC entered into a service arrangement with CONSOL Energy to provide certain general and administrative services. These services are paid monthly based on an agreed upon fixed fee that is reset annually. See Note 27 - Related Party Transactions of the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information. The amount of general and administrative costs related to PA Operations was $15 million for the year ended December 31, 2015, compared to $26 million for the year ended December 31, 2014. Refer to the discussion of total Company general and administrative costs contained in the section "Net (Loss) Income Attributable to CONSOL Energy Shareholders" of this annual report for a detailed cost explanation.

Other Corporate Expense

Other corporate expense is comprised of expenses for stock-based compensation and the short-term incentive compensation program. These expenses include costs that are directly related to each coal segment along with a portion of costs that are allocated to each segment based on a percentage of total labor dollars. For the year ended December 31, 2015, other corporate expenses were $22 million compared to $39 million for the year ended December 31, 2014. The $17 million decrease was primarily due to PA Operations representing a smaller portion of total coal labor dollars and lower short-term incentive compensation payouts.

Interest Expense

Interest expense, net of amounts capitalized, of $3 million for the year ended December 31, 2015 is primarily comprised of interest on the CNXC revolving credit facility. Upon execution of the CNXC IPO on July 7, 2015, CNXC drew down an initial $200,000 on the credit facility; $185,000 is currently drawn upon at December 31, 2015. No such expense was incurred during the year ended December 31, 2014.

VIRGINIA (VA) OPERATIONS COAL SEGMENT

The VA Operations coal segment's principal activities are the mining, preparation and marketing of low volatile metallurgical coal to metal and coke producers. The segment also includes general and administrative activities as well as various other activities assigned to the VA Operations coal segment but not allocated to each individual mine and, therefore, are not included in unit cost presentation. For the years ended December 31, 2015 and 2014, the segment included the Buchanan Mine and the corresponding preparation plant facilities.

The VA Operations coal segment had earnings before income tax of $71 million for the year ended December 31, 2015, compared to earnings before income tax of $11 million for the year ended December 31, 2014. The VA Operations coal revenue and cost components on a per unit basis for these periods are as follows:

| | For the Years Ended December 31, | | | | | |
|---|---|---|---|---|---|---|
| | 2015 | 2014 | Variance | | Percent Change | |
| Company Produced VA Operations Tons Sold (in millions) | 4.4 | 4.1 | 0.3 | | 7.3 | % |
| Average Sales Price Per VA Operations Ton Sold | $56.70 | $71.80 | $(15.10 | ) | (21.0 | %) |
| | | | | | | |
| Total Operating Costs Per Ton Sold | $34.15 | $44.94 | $(10.79 | ) | (24.0 | %) |
| Total Direct Administrative and Selling Costs Per Ton Sold | 1.05 | 1.42 | (0.37 | ) | (26.1 | %) |
| Total Royalty/Production Taxes Per Ton Sold | 3.16 | 4.45 | (1.29 | ) | (29.0 | %) |
| Total Depreciation, Depletion and Amortization Costs Per Ton Sold | 8.42 | 9.86 | (1.44 | ) | (14.6 | %) |
| Total Costs Per VA Operations Ton Sold | $46.78 | $60.67 | $(13.89 | ) | (22.9 | %) |
| Average Margin Per VA Operations Ton Sold | $9.92 | $11.13 | $(1.21 | ) | (10.9 | %) |

Coal Sales

VA Operations produced coal outside sales revenues were $248 million for the year ended December 31, 2015, compared to $297 million for the year ended December 31, 2014. The $49 million decrease was attributable to a $15.10 per ton lower average sales price. Average sales prices for VA Operations coal decreased in the period-to-period comparison due to the continued weakening of the global metallurgical coal market.

Freight Revenue

Freight revenue increased in the period-to-period comparison due to an increase in shipments where CONSOL Energy contractually provides transportation services.

Cost of Coal Sold

Total cost of coal sold for VA Operations was $204 million for the year ended December 31, 2015, or $47 million lower than the $251 million for the year ended December 31, 2014. Total costs per VA Operations ton sold were $46.78 per ton in the year ended December 31, 2015, compared to $60.67 per ton in the year ended December 31, 2014. The decrease in total dollars and unit costs per VA Operations ton sold was primarily due to a modification of the operating shifts at the Buchanan Mine and other cost control measures that were implemented due to the weak metallurgical coal market. The mine went from three operating shifts to two operating shifts beginning in May 2014, which resulted in lower wage and wage related expenses, royalty and production taxes, and maintenance and supply costs, as well as a reduction in the gallons of wastewater treated. Also contributing to the decrease was the effect of the Pension and OPEB plan modifications for active employees in September 2014. The decrease was offset, in part, by an increase in the number of degasification wells drilled.

Other Costs And Expenses

Other costs resulted in income for VA Operations of $57 million for the year ended December 31, 2015 compared to expense of $6 million for the year ended December 31, 2014. The decrease of $63 million was due to the following:

| | For the Years Ended December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | Variance |
| OPEB Plan Changes | $(67) | $— | $(67) |
| Closed and Idle Mines | 8 | 6 | 2 |
| Other | 2 | — | 2 |
| Other Costs | $(57) | $6 | $(63) |

- Income of $67 million related to OPEB plan changes was the result of modifications made to the OPEB plan in May 2015 for retired employees. Refer to the discussion of total Company long-term liabilities contained in the section "Net (Loss) Income Attributable to CONSOL Energy Shareholders" of this annual report for more information.
- Closed and idle mines increased $2 million in the period-to-period comparison due to various transactions that occurred throughout both periods, none of which were individually material.
- Other increased $2 million in the period-to-period comparison due to various transactions that occurred throughout both periods, none of which were individually material.

Depreciation, depletion and amortization increased $6 million, primarily as a result of additional assets placed in service in the period-to-period comparison.

Freight Expense

Freight expense increased in the period-to-period comparison due to an increase in shipments where CONSOL Energy contractually provides transportation services.

General and Administrative Expense

General and administrative costs allocated to the VA Operations coal segment were $4 million for the year ended December 31, 2015, compared to $9 million for the year ended December 31, 2014. Refer to the discussion of total Company general and administrative costs contained in the section "Net (Loss) Income Attributable to CONSOL Energy Shareholders" of this annual report for a detailed cost explanation.

Other Corporate Expense

Other corporate expenses were $10 million for the year ended December 31, 2015, compared to $9 million for the year ended December 31, 2014. The $1 million increase was due to various transactions that occurred throughout both periods, none of which were individually material.

OTHER COAL SEGMENT

The Other coal segment primarily includes coal terminal operations, idle mine activities and purchased coal activities, as well as various other activities not assigned to either PA Operations or VA Operations. The Other coal segment also includes activities related to mining, preparation and marketing of thermal coal to power generators geographically separated from PA Operations. For the years ended December 31, 2015 and 2014, the segment included the Miller Creek Complex.

The Other coal segment had earnings before income tax of $22 million for the year ended December 31, 2015, compared to a loss before income tax of $33 million for the year ended December 31, 2014. The Other coal revenue and cost components on a per unit basis for these periods are as follows:

| | For the Years Ended December 31, | | | |
|---|---|---|---|---|
| | 2015 | 2014 | Variance | Percent Change |
| Company Produced Other Operations Tons Sold (in millions) | 1.9 | 2.2 | (0.3) | (13.6)% |
| Average Sales Price Per Other Operations Ton Sold | $60.01 | $60.12 | $(0.11) | (0.2)% |
| | | | | |
| Total Operating Costs Per Ton Sold | $47.01 | $48.95 | $(1.94) | (4.0)% |
| Total Direct Administrative and Selling Costs Per Ton Sold | 0.90 | 1.14 | (0.24) | (21.1)% |
| Total Royalty/Production Taxes Per Ton Sold | 5.02 | 5.12 | (0.10) | (2.0)% |
| Total Depreciation, Depletion and Amortization Costs Per Ton Sold | 3.63 | 3.62 | 0.01 | 0.3% |
| Total Costs Per Other Operations Ton Sold | $56.56 | $58.83 | $(2.27) | (3.9)% |
| Average Margin Per Other Operations Ton Sold | $3.45 | $1.29 | $2.16 | 167.4% |

Coal Sales

Other produced coal outside sales revenues were $119 million for the year ended December 31, 2015, compared to $129 million for the year ended December 31, 2014. The $10 million decrease was attributable to a 0.3 million decrease in tons sold and an $0.11 per ton lower average sales price. The lower average coal sales price in the current period was the result of the overall decline in the domestic thermal coal markets.

Purchased coal sales consisted of revenues from coal purchased from third parties and sold directly to CONSOL Energy's customers. Purchased coal sales revenue totaled $2 million for the year ended December 31, 2015, compared to $9 million for the year ended December 31, 2014. The decrease in the period-to-period comparison was a result of lower coal volumes that needed to be purchased to fulfill various contracts.

Other Outside Sales

Other outside sales revenue consists of revenues from the Company's coal terminal operations. Coal terminal operations sales revenues were $31 million for the year ended December 31, 2015, compared to $41 million for the year ended December 31, 2014. The $10 million decrease in the period-to-period comparison was primarily due to a decrease in thru-put volumes.

Freight Revenue

Freight revenue was $9 million for the year ended December 31, 2015, compared to $10 million for the year ended December 31, 2014. The $1 million decrease in freight revenue was due to decreased shipments where CONSOL Energy contractually provides transportation services.

Miscellaneous Other Income

Miscellaneous other income was $74 million for the year ended December 31, 2015, compared to $101 million for the year ended December 31, 2014. The change is due to the following items:

| | For the Years Ended December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | Variance |
| Equity in Earnings of Affiliates | $8 | $19 | $(11) |
| Blacksville Fire Settlement | — | 10 | (10) |
| Rental Income | 37 | 42 | (5) |
| Royalty Income | 15 | 20 | (5) |
| Right of Way Sales | 8 | 7 | 1 |
| Other | 6 | 3 | 3 |
| Total Miscellaneous Other Income | $74 | $101 | $(27) |

- Equity in earnings of affiliates decreased $11 million due to the sale of the Company's interest in one equity affiliate in the year ended December 31, 2015, compared to the sale of two equity affiliates in year ended December 31, 2014.
- During the year ended December 31, 2014, $10 million of business interruptions proceeds were received related to the Blacksville No. 2 Mine fire that occurred in March 2013.
- Rental income decreased $5 million due to a decrease in revenue received from the buyout of certain equipment that was leased by CONSOL Energy and then subleased to a third-party.
- Royalty income decreased $5 million primarily due to the overall decrease in domestic coal pricing.
- Right of way sales increased $1 million due to additional revenue earned from the sale of several right of ways during the year ended December 31, 2015.
- Other income increased $3 million due to various transactions that occurred throughout both periods, none of which were individually material.

Gain on Sale of Assets

Gain on sale of assets increased $33 million in the period-to-period comparison, primarily due to the sale of the Company's 49% interest in Western Allegheny Energy. See Note 3 - Acquisitions and Dispositions in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional details.

Cost of Coal Sold

Total cost of coal attributable to the Other coal segment was $113 million for the year ended December 31, 2015, or $13 million lower than the $126 million for the year ended December 31, 2014. Total costs per Other Operations ton sold were $56.56 for the year ended December 31, 2015, compared to $58.83 per ton for the year ended December 31, 2014. The decrease in cost of coal sold was primarily the result of the Pension and OPEB plan modifications for active employees in September 2014.

Other Costs And Expenses

Other costs and expenses related to the Other coal segment were $85 million for the year ended December 31, 2015, compared to $141 million for the year ended December 31, 2014. The decrease of $56 million was due to the following items:

| | For the Years Ended December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | Variance |
| OPEB Plan Changes | $(48) | $— | $(48) |
| Closed and Idle Mines | 22 | 36 | (14) |
| Purchased Coal | 1 | 13 | (12) |
| Coal Terminal Operations | 19 | 25 | (6) |
| Coal Reserve Holding Costs | 6 | 10 | (4) |
| Lease Rental Expense | 27 | 30 | (3) |
| UMWA OPEB Expense | 47 | — | 47 |

| | | | | |
|---|---|---|---|---|
| Other | 11 | 27 | (16 | ) |
| Total Other Costs | $85 | $141 | $(56 | ) |

- Income of $48 million related to OPEB plan changes was the result of modifications made to the OPEB plan in May 2015 for retired employees. Refer to the discussion of total Company long-term liabilities contained in the section "Net (Loss) Income Attributable to CONSOL Energy Shareholders" of this annual report for more information.
- Closed and idle mine costs decreased approximately $14 million primarily due to a $7 million decrease in property taxes and a $5 million decrease in permitting and compliance costs. The remaining decrease was due to various transactions that occurred throughout both periods, none of which were individually material.
- Purchased coal costs decreased $12 million due to lower coal volumes that were purchased in the current year to fulfill various contracts.
- Coal terminal operations costs decreased $6 million due to decreased thru-put volumes in the current period.
- Coal reserve holding costs decreased $4 million in the period-to-period comparison due to various transactions that occurred throughout both periods, none of which were individually material.
- Lease rental expense decreased $3 million primarily due to the buyout of certain equipment in the current year that was leased by CONSOL Energy.
- UMWA OPEB expense increased $47 million primarily due to a change in the allocation methodology. Refer to the discussion of total Company long-term liabilities contained in the section "Net (Loss) Income Attributable to CONSOL Energy Shareholders" of this annual report for more information.
- Other decreased $16 million in the period-to-period comparison primarily due to a property tax reimbursement in the 2015 period related to property dispositions along with various transactions that occurred throughout both periods, none of which were individually material.

Direct administrative expense consists primarily of labor and benefits and consulting expenses that relate to coal terminal operations and idle mine locations. Direct administrative expense decreased $2 million in the period-to-period comparison primarily due to ongoing cost reduction efforts, as well as the Company reorganization that occurred in the 2015 period.

Royalty and production taxes increased $1 million in the period-to-period comparison due to various transactions that occurred throughout both periods, none of which were individually material.

Depreciation, depletion and amortization decreased $8 million primarily due to a $6 million decrease in the asset retirement obligation at the Fola Mining Complex. The remaining decrease was a result of fewer assets placed in service in the period-to-period comparison.

Freight Expense

Freight expense was $9 million for the year ended December 31, 2015, compared to $10 million for the year ended December 31, 2014. The $1 million decrease in the period-to-period comparison was due to decreased shipments where CONSOL Energy contractually provides transportation services.

General and Administrative Expense

General and administrative costs allocated to the Other coal segment were $11 million for the year ended December 31, 2015, compared to $10 million for the year ended December 31, 2014. Refer to the discussion of total Company general and administrative costs contained in the section "Net (Loss) Income Attributable to CONSOL Energy Shareholders" of this annual report for a detailed cost explanation.

Other Corporate Expense

Other corporate expenses were $8 million for the year ended December 31, 2015, compared to $7 million for the year ended December 31, 2014. The $1 million increase was primarily due to an increase in stock-based compensation expense.

OTHER DIVISION ANALYSIS for the year ended December 31, 2015 compared to the year ended December 31, 2014:

The Other division includes various corporate activities that are not allocated to the E&P or Coal divisions. In previous periods, this division included activity from the sales of industrial supplies (this subsidiary was sold in December 2014). The Other division had a loss before income tax of $319 million for the year ended December 31, 2015 compared to a loss before income tax of $416 million for the year ended December 31, 2014. The Other division also includes the total company income tax benefit of $134 million for the year ended December 31, 2015 compared to the total company income tax expense of $14 million for the year ended December 31, 2014.

| | For the Years Ended December 31, | | | |
|---|---|---|---|---|
| | 2015 | 2014 | Variance | Percent Change |
| Other Outside Sales | $— | $235 | $(235) | (100.0)% |
| Loss on Sale of Assets | — | (31) | 31 | (100.0)% |
| Miscellaneous Other Income | 3 | 2 | 1 | 50.0 % |
| Total Revenue | 3 | 206 | (203) | (98.5)% |
| Miscellaneous Operating Expense | 64 | 310 | (246) | (79.4)% |
| Depreciation, Depletion & Amortization | — | 2 | (2) | (100.0)% |
| Loss on Debt Extinguishment | 68 | 95 | (27) | (28.4)% |
| Interest Expense | 190 | 215 | (25) | (11.6)% |
| Total Other Costs | 322 | 622 | (300) | (48.2)% |
| Loss Before Income Tax | (319) | (416) | 97 | (23.3)% |
| Income Tax (Benefit) Expense | (134) | 14 | (148) | (1,057.1)% |
| Net Loss | $(185) | $(430) | $245 | (57.0)% |

Outside Sales

There were no outside sales revenues from the Other division for the year ended December 31, 2015, compared to $235 million for the year ended December 31, 2014. The decrease was related to the divestiture of the Company's industrial supplies subsidiary in December 2014.

Loss on Sale of Assets

The loss on sale of assets was related to the divestiture of the Company's industrial supplies subsidiary in December 2014. No such transactions occurred in the current period.

Miscellaneous Other Income

Miscellaneous other income was $3 million for the year ended December 31, 2015, compared to $2 million for the year ended December 31, 2014. The increase was due to various transactions that occurred throughout both periods, none of which were individually material.

Miscellaneous Operating Expense

Miscellaneous operating expense related to the Other division was $64 million for the year ended December 31, 2015, compared to $310 million for the year ended December 31, 2014. The $246 million decrease was due to the following items:

| | For the Years Ended December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | Variance |
| Industrial Supplies | $— | $231 | $(231) |
| Long-Term Liability Plan Changes | — | 10 | (10) |
| Corporate Initiative Fees and Other Legal Charges | — | 10 | (10) |
| Pension Settlement | 19 | 29 | (10) |
| Revolver Modification Fees | — | 3 | (3) |
| Bank Fees | 17 | 19 | (2) |
| Industrial Supplies Working Capital Settlement | 6 | — | 6 |
| Pension Expense | 6 | — | 6 |
| Severance Payments | 8 | — | 8 |
| Other | 8 | 8 | — |
| Miscellaneous Operating Expense | $64 | $310 | $(246) |

- No Industrial Supplies expense were incurred during the year ended December 31, 2015. Industrial Supplies expense was $231 million in the year ended December 31, 2014. The decrease is due to the divestiture of the Company's industrial supplies subsidiary in December 2014. See Note 3 - Acquisitions and Dispositions in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional details.
- Long-Term Liability Plan Changes include $36 million of income as a result of amendments to the pension and OPEB plans, which were adopted during the third quarter of 2014, offset by $46 million of expense for cash payments made to active employees related to changes in the OPEB plan during the year ended December 31, 2014. See Note 16—Pension and Other Postretirement Benefit Plans in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional details related to the total Company expense.
- Corporate initiative fees and other legal charges reflect various fees for services related to corporate initiatives to evaluate structure changes and various asset sales. These fees also include legal charges related to land title issues raised by the Company's joint venture partners in the prior period. The $10 million decrease was due to various transactions that occurred throughout both periods, none of which were individually material. See Note 11 - Property, Plant and Equipment and Note 24 - Commitments and Contingencies in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.
- Pension settlement expense is required when lump sum distributions made for a given plan year exceed the total of the service and interest costs for that same plan year. Settlement accounting was triggered in both periods. See Note 16 - Pension and Other Postretirement Benefit Plans in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional detail.
- Revolver modification fees decreased $3 million due to an acceleration of previously deferred financing fees in the prior period.
- Bank fees decreased $2 million in the period-to-period comparison due to various transactions that occurred throughout both periods, none of which were individually material.
- Industrial supplies working capital settlement of $6 million is the settlement of working capital adjustments and other matters in the year ended December 31, 2015 related to the divestiture of the Company's industrial supplies subsidiary in December 2014.
- Actuarially-calculated amortization of $6 million was included in the Other division in the year ended December 31, 2015 due to modifications made to the Pension plan in September 2014. Refer to the discussion of total Company long-term liabilities contained in the section "Net (Loss) Income Attributable to CONSOL Energy Shareholders" of this Annual Report on Form 10-K for more information.
- Severance Payments increased $8 million due to the Company reorganization that occurred in the year ended December 31, 2015.
- Other corporate items remained consistent in the period-to-period comparison.

Depreciation, Depletion & Amortization

Deprecation, depletion, & amortization decreased $2 million in the period-to-period comparison. The decrease was related to the divestiture of the Company's industrial supplies subsidiary in December 2014.

Loss on Debt Extinguishment

Loss on debt extinguishment of $68 million was recognized in the year ended December 31, 2015 due to the partial purchase of the 8.25% senior notes that were due in 2020 at an average price equal to 104.6% of the principal amount, and the partial purchase of the 6.375% senior notes that were due in 20121 at an average price equal to 105.0% of the principal amount. Loss on debt extinguishment of $95 million was recognized in the year ended December 31, 2014 related to the early extinguishment of debt due to the purchase of all of the 8.00% senior notes that were due in 2017 at an average premium of 104.0% of the principal amount, and the partial purchase of the 8.25% senior notes that were due in 2020 at an average premium of 107.5% of the principal amount.

Interest Expense

Interest expense of $190 million was recognized in the year ended December 31, 2015 compared to $215 million in the year ended December 31, 2014. The $25 million decrease was primarily due to the partial payoff of the 2020 and 2021 bonds in the year ended December 31, 2015 and the early payoff of the 2017 bonds issued in March 2015 and the 2022 bonds issued in April and August 2014. The decrease was offset, in part, by interest on short-term borrowings.

Income Taxes

The effective income tax rate was 26.9% for the year ended December 31, 2015 compared to 7.7% for the year ended December 31, 2014. The effective rates for the years ended December 31, 2015 and 2014 were calculated using the annual effective rate projections on recurring earnings and include tax liabilities related to certain discrete transactions. For the year ended December 31, 2015, CONSOL Energy recognized certain tax benefits related to a prior-year tax provision. In order to maximize cash flow, CONSOL Energy elected to take bonus depreciation upon filing the 2014 tax return. As a result, CONSOL Energy realized a cash refund of $24 million for 2014. The bonus depreciation also created a net operating loss which was carried back to 2012. The carryback resulted in an additional cash refund of $31 million. However, these changes resulted in an expense of $27 million related to decreased percentage depletion deductions, offset, in part, by $5 million of tax benefit due to changes in the deduction for certain stock-related compensation.

For the year ended December 31, 2014, CONSOL Energy recognized certain tax benefits as a result of changes in estimates related to a prior-year tax provision. That resulted in a benefit of $10 million primarily related to increased percentage of depletion. Also, the Internal Revenue Service issued its audit report relating to the examination of CONSOL Energy's 2008 and 2009 U.S. income tax returns during the year ended December 31, 2014. The result of these findings was a change in timing of certain tax deductions which increased the tax benefit of percentage of depletion by $7 million. Also, as a result of closing the IRS audit, CONSOL Energy was required to file amended state income tax returns. The Company filed the required amended returns and realized a discrete state income tax charge of $5 million which was offset by a federal income tax benefit of $2 million. See Note 7 - Income Taxes in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.

Upon changes in facts and circumstances, management may conclude that deferred tax assets for which no valuation allowance is currently recorded may not be realizable in future periods, resulting in a future charge to record a valuation allowance. A valuation allowance is required when it is more likely than not that all or a portion of a deferred tax asset will not be realized. All available evidence, both positive and negative, must be considered in determining the need for a valuation allowance. Positive evidence considered includes financial and tax earnings generated over the past three years, future income projections based on existing fixed price contracts and forecasted expenses, reversals of financial to tax temporary differences and the implementation of and/or ability to employ various tax planning strategies. Negative evidence includes financial and tax losses generated in prior periods and the inability to achieve forecasted results for those periods. Existing valuation allowances are re-examined under the same standards of positive and negative evidence. If it is determined that it is more likely than not that a deferred tax asset will be realized, the appropriate amount of the valuation allowance, if any, is released. Deferred tax assets and liabilities are also re-measured to reflect changes in underlying tax rates due to law changes. For the year ended December 31, 2015, a review of positive and negative evidence regarding these tax benefits concluded that the valuation allowances for various CONSOL Energy subsidiaries was warranted. As a result,CONSOL Energy recorded a valuation allowance of $65 million against certain deferred tax assets that the Company determined would not be realized.

| | For the Years Ended December 31, | | | |
|---|---|---|---|---|
| | 2015 | 2014 | Variance | Percent Change |
| Total Company Earnings Before Income Tax | $(499) | $183 | $(682) | (372.7)% |
| Income Tax (Benefit) Expense | $(134) | $14 | $(148) | (1,057.1)% |
| Effective Income Tax Rate | 26.9% | 7.7% | 19.2% | |

Results of Operations: Year Ended December 31, 2014 Compared with the Year Ended December 31, 2013
Net Income Attributable to CONSOL Energy Shareholders
CONSOL Energy reported net income attributable to CONSOL Energy shareholders of $163 million, or income of $0.70 per diluted share, for the year ended December 31, 2014, compared to net income attributable to CONSOL Energy shareholders of $660 million, or income of $2.87 per diluted share, for the year ended December 31, 2013.

CONSOL Energy consists of two principal business divisions: Exploration and Production (E&P) and Coal. The total E&P division includes four segments: Marcellus, Utica, Coalbed Methane (CBM) and Other Gas. The Coal division includes three segments: Pennsylvania (PA) operations, Virginia (VA) operations and Other Coal.

The total E&P division contributed income before income tax of $190 million for the year ended December 31, 2014 compared to a loss before income tax of $2 million for the year ended December 31, 2013. Total E&P production was 235.7 Bcfe for the year ended December 31, 2014 compared to 172.4 Bcfe for the year ended December 31, 2013.

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) | 2014 | 2013 | Variance | Percent Change |
| LIQUIDS | | | | |
| NGLs: | | | | |
| Sales Volume (MMcfe) | 15,475 | 2,628 | 12,847 | 488.9% |
| Sales Volume (Mbbls) | 2,579 | 438 | 2,141 | 488.8% |
| Gross Price ($/Bbl) | $35.70 | $53.76 | $(18.06) | (33.6)% |
| Gross Revenue | $92,136 | $23,541 | $68,595 | 291.4% |
| | | | | |
| Oil: | | | | |
| Sales Volume (MMcfe) | 681 | 634 | 47 | 7.4% |
| Sales Volume (Mbbls) | 114 | 106 | 8 | 7.5% |
| Gross Price ($/Bbl) | $89.10 | $89.58 | $(0.48) | (0.5)% |
| Gross Revenue | $10,108 | $9,471 | $637 | 6.7% |
| | | | | |
| Condensate: | | | | |
| Sales Volume (MMcfe) | 3,298 | 382 | 2,916 | 763.4% |
| Sales Volume (Mbbls) | 550 | 64 | 486 | 759.4% |
| Gross Price ($/Bbl) | $66.96 | $81.06 | $(14.10) | (17.4)% |
| Gross Revenue | $36,808 | $5,156 | $31,652 | 613.9% |
| | | | | |
| GAS | | | | |
| Sales Volume (MMcf) | 216,260 | 168,737 | 47,523 | 28.2% |
| Sales Price ($/Mcf) | $4.02 | $3.72 | $0.30 | 8.1% |
| Gross Revenue | $868,329 | $627,445 | $240,884 | 38.4% |

| | | | | |
|---|---|---|---|---|
| Hedging Impact ($/Mcf) | $0.11 | $0.45 | $(0.34) | (75.6)% |
| Gain on Commodity Derivative Instruments - Cash Settlement | $23,193 | $75,255 | $(52,062) | (69.2)% |

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The average sales price, including the effects of derivatives instruments, and average costs for all active gas operations were as follows:

| | For the Years Ended December 31, | | | |
|---|---|---|---|---|
| | 2014 | 2013 | Variance | Percent Change |
| Average Sales Price (per Mcfe) | $4.37 | $4.30 | $0.07 | 1.6 % |
| Average Costs (per Mcfe) | 3.31 | 3.51 | (0.20 ) | (5.7 )% |
| Margin | $1.06 | $0.79 | $0.27 | 34.2 % |

Total E&P division Natural Gas, NGLs, and Oil outside sales revenues were $1,008 million for the year ended December 31, 2014 compared to $666 million for the year ended December 31, 2013. The increase was primarily due to the 36.7% increase in total volumes sold, along with a 1.6% increase in overall average sales price per Mcfe. The increase in average sales price is the result of a $0.30 per Mcfe increase in general market prices and the $0.11 per Mcfe increase in sales of NGLs, oil and condensate. The increase was offset, in part, by the $0.34 per Mcf decrease resulting from various transactions relating to our hedging program. These financial hedges represented approximately 159.9 Bcf of our produced gas sales volumes for the year ended December 31, 2014 at an average gain of $0.15 per Mcf. For the year ended December 31, 2013, these financial hedges represented approximately 84.3 Bcf of our produced gas sales volumes at an average gain of $0.89 per Mcf.

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

- The improvement in the unit costs is primarily due to the 36.7% increase in volumes in the period-to-period comparison and the shift to lower cost Marcellus and Utica Shale production. Marcellus production made up 47.4% of natural gas and liquid sales volume for the year ended December 31, 2014 compared to 33.6% in the year ended December 31, 2013.
- Lifting costs per unit decreased in the period-to-period comparison due to the increase in sales volumes. The decrease was offset, in part, by an increase in total dollars relating to higher salt water disposal, well site maintenance costs, and costs related to wells operated by our joint-venture partners.
- Gathering expense per unit also decreased in the period-to-period comparison due to the increase in sales volumes. The decrease in unit costs was partially offset by an increase in total dollars related to an increase in firm transportation costs and increased processing fees associated with natural gas liquids (NGLs).

The total Coal division contributed $409 million of earnings before income tax from continuing operations for the year ended December 31, 2014 compared to $345 million for the year ended December 31, 2013. The total Coal division sold 32.4 million tons of coal produced from continuing operations for the year ended December 31, 2014 compared to 28.8 million tons for the year ended December 31, 2013.

The average sales price and average costs per ton for continuing coal operations were as follows:

| | For the Years Ended December 31, | | | |
|---|---|---|---|---|
| | 2014 | 2013 | Variance | Percent Change |
| Average Sales Price Per Ton Sold | $63.03 | $69.34 | $(6.31 ) | (9.1 )% |
| Total Costs Per Ton Sold | 46.91 | 50.78 | (3.87 ) | (7.6 )% |
| Margin | $16.12 | $18.56 | $(2.44 ) | (13.1 )% |

The lower average sales price per ton sold reflects a decrease in the global metallurgical coal markets, the oversupply of coal used in steelmaking, and overall lower coal pricing due to the roll-off of some higher-priced legacy contracts. The Coal division priced 6.4 million tons on the export market for the year ended December 31, 2014 compared to 8.0 million tons for the year ended December 31, 2013. All other tons were sold on the domestic market.

Changes in the average cost of goods sold per ton were primarily attributable to the increase in tons sold. Total cost per ton sold was also impacted by the decrease in operating shifts and other cost control measures implemented at our Buchanan Mine. The mine went from three operating shifts to two operating shifts beginning in May 2014. The decrease in total costs per ton sold was offset, in part, by geological conditions at Enlow Fork Mine and Harvey Mine.
CONSOL Energy's Other division includes other business activities not assigned to the E&P or Coal division, income taxes, and industrial supplies activity (this subsidiary was sold in December 2014). The Other division had a net loss from continuing operations of $430 million for the year ended December 31, 2014 compared to a net loss from continuing operations of $264 million for the year ended December 31, 2013.

General and administrative costs are allocated between divisions (E&P, Coal and Other) based primarily on percentage of total revenue and percentage of total projected capital expenditures. General and administrative costs are excluded from the E&P and Coal unit costs above. Total general and administrative costs were made up of the following items:

| | For the Years Ended December 31, | | | |
|---|---|---|---|---|
| (in millions) | 2014 | 2013 | Variance | Percent Change |
| Continuing Operations General and Administrative Expense | $110 | $80 | $30 | 37.5 % |
| Discontinued Operations General and Administrative Expense | — | 39 | (39) | (100.0)% |
| Total Company General and Administrative Expense | $110 | $119 | $(9) | (7.6)% |

Overall, total Company general and administrative expenses decreased $9 million in the period-to-period comparison. This was primarily due to reduced staffing and cost control measures following the December 2013 sale of five of our West Virginia coal mines. See Note 2 - Discontinued Operations in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional details.

Total Company long-term liabilities, 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 expense for continuing operations related to our actuarially calculated liabilities was $132 million for the year ended December 31, 2014 compared to $152 million for the year ended December 31, 2013. The decrease was primarily due to an increase in the discount rate assumptions used to calculate expense for benefit plans at the measurement date, which is December 31, along with a decrease in pension settlement expense. Pension settlement expense is required when lump sum distributions for a plan year exceed the total of the service and interest cost for the plan year. Pension settlement expense was $29 million for the year ended December 31, 2014, compared to $39 million for the year ended December 31, 2013. Additionally, a part of the decrease was due to modifications made to the OPEB and Pension plans, which required remeasurement at September 30, 2014. Not included in the long-term liability expense totals discussed above are curtailment gains of $36 million, and $46 million of expense for cash payments made to active employees, both of which arose from the modifications to the OPEB and Pension plans during the year ended December 31, 2014. The pension settlement expense, curtailment gains, and cash payment expenses were not allocated to individual operating segments and are therefore not included in unit costs presented for the E&P or Coal divisions. See Note 16—Pension and Other Postretirement Benefit Plans and Note 17—Coal Workers' Pneumoconiosis (CWP) and Workers' Compensation in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional details related to the total Company expense decrease.

TOTAL E&P DIVISION ANALYSIS for the year ended December 31, 2014 compared to the year ended December 31, 2013:

The E&P division had earnings before income tax of $190 million for the year ended December 31, 2014 compared to a loss before income tax of $2 million for the year ended December 31, 2013. Variances by individual E&P segment are discussed below.

| | For the Year Ended December 31, 2014 | | | | | Difference to Year Ended December 31, 2013 | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Marcellus | Utica | CBM | Other Gas | Total Gas | Marcellus | Utica | CBM | Other Gas | Total Gas |
| Sales: | | | | | | | | | | |
| Produced | $458 | $87 | $340 | $120 | $1,005 | $223 | $83 | $37 | $(1 ) | $342 |
| Related Party | — | — | 3 | — | 3 | — | — | — | — | — |
| Total Outside Sales | 458 | 87 | 343 | 120 | 1,008 | 223 | 83 | 37 | (1 ) | 342 |
| Gain on Commodity Derivative Instruments | 15 | 1 | 4 | 3 | 23 | (2 ) | 1 | (29 ) | (22 ) | (52 ) |
| Production Royalty Interest | — | — | — | 82 | 82 | — | — | — | 19 | 19 |
| Purchased Gas | — | — | — | 9 | 9 | — | — | — | 2 | 2 |
| Miscellaneous Other Income | — | — | — | 67 | 67 | — | — | — | 30 | 30 |
| Gain on Sale of Assets | — | — | — | 46 | 46 | — | — | — | 25 | 25 |
| Total Revenue and Other Income | 473 | 88 | 347 | 327 | 1,235 | 221 | 84 | 8 | 53 | 366 |
| Lifting | 26 | 16 | 35 | 32 | 109 | 6 | 13 | — | 2 | 21 |
| Ad Valorem, Severance, and Other Taxes | 17 | 1 | 12 | 9 | 39 | 8 | 1 | 3 | (2 ) | 10 |
| Transportation, Gathering, and Compression | 110 | 7 | 108 | 33 | 258 | 60 | 7 | (6 ) | (4 ) | 57 |
| Direct Administrative and Selling | 36 | 4 | 10 | 5 | 55 | 10 | 2 | 2 | (8 ) | 6 |
| Depreciation, Depletion and Amortization | 132 | 19 | 90 | 83 | 324 | 65 | 16 | (2 ) | 4 | 83 |
| General & Administration | — | — | — | 64 | 64 | — | — | — | 25 | 25 |
| Production Royalty Interest | — | — | — | 70 | 70 | — | — | — | 17 | 17 |
| Purchased Gas | — | — | — | 7 | 7 | — | — | — | 2 | 2 |
| Exploration and Other Costs | — | — | — | 23 | 23 | — | — | — | (38 ) | (38 ) |
| Other Corporate Expenses | — | — | — | 87 | 87 | — | — | — | (9 ) | (9 ) |
| Total Exploration and Production Costs | 321 | 47 | 255 | 413 | 1,036 | 149 | 39 | (3 ) | (11 ) | 174 |
| Interest Expense | — | — | — | 9 | 9 | — | — | — | — | — |
| Total E&P Division Costs | 321 | 47 | 255 | 422 | 1,045 | 149 | 39 | (3 ) | (11 ) | 174 |
| Earnings (Loss) Before Income Tax | $152 | $41 | $92 | $(95 ) | $190 | $72 | $45 | $11 | $64 | $192 |

MARCELLUS GAS SEGMENT

The Marcellus segment had earnings before income tax of $152 million for the year ended December 31, 2014 compared to earnings before income tax of $80 million for the year ended December 31, 2013.

| | For the Years Ended December 31, | | | |
|---|---|---|---|---|
| | 2014 | 2013 | Variance | Percent Change |
| Marcellus Gas Sales Volumes (Bcf) | 99.4 | 55.0 | 44.4 | 80.7 % |
| NGLs Sales Volumes (Bcfe)* | 10.9 | 2.5 | 8.4 | 336.0 % |
| Condensate Sales Volumes (Bcfe)* | 1.4 | 0.3 | 1.1 | 366.7 % |
| Total Marcellus Gas Sales Volumes (Bcfe)* | 111.7 | 57.8 | 53.9 | 93.3 % |
| | | | | |
| Average Sales Price - Gas (Mcf) | $3.83 | $3.77 | $0.06 | 1.6 % |
| Gain on Commodity Derivative Instruments - Cash Settlement- Gas (Mcf) | $0.15 | $0.32 | $(0.17) | (53.1)% |
| Average Sales Price - NGLs (Mcfe)* | $5.77 | $9.09 | $(3.32) | (36.5)% |
| Average Sales Price - Condensate (Mcfe)* | $10.47 | $13.73 | $(3.26) | (23.7)% |
| | | | | |
| Total Average Marcellus Sales Price (per Mcfe) | $4.24 | $4.35 | $(0.11) | (2.5)% |
| Average Marcellus Lifting Costs (per Mcfe) | 0.23 | 0.34 | (0.11) | (32.4)% |
| Average Marcellus Ad Valorem, Severance, and Other Taxes (per Mcfe) | 0.16 | 0.16 | — | — % |
| Average Marcellus Transportation, Gathering, and Compression Costs (per Mcfe) | 0.98 | 0.86 | 0.12 | 14.0 % |
| Average Marcellus Direct Administrative and Selling (per Mcfe) | 0.32 | 0.45 | (0.13) | (28.9)% |
| Average Marcellus Depreciation, Depletion and Amortization Costs (per Mcfe) | 1.19 | 1.17 | 0.02 | 1.7 % |
| Total Average Marcellus Costs (per Mcfe) | $2.88 | $2.98 | $(0.10) | (3.4)% |
| Average Margin for Marcellus (per Mcfe) | $1.36 | $1.37 | $(0.01) | (0.7)% |

* 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 outside sales revenues were $458 million for the year ended December 31, 2014 compared to $235 million for the year ended December 31, 2013. The $223 million increase is primarily due to a 93.3% increase in total volumes sold offset, in part, by a 2.5% decrease in total average sales prices in the period-to-period comparison. The 53.9 Bcfe increase in sales volumes was primarily due to additional wells coming on-line from our ongoing drilling program.

The $0.11 per Mcfe decrease in Marcellus total average sales price was primarily the result of the $0.17 per Mcf decrease resulting from various transactions relating to our hedging program (See Note 23 - Derivative Instruments in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional details) offset, in part, by a $0.06 per Mcf increase in gas market prices. These financial hedges represented approximately 70.4 Bcf of our produced Marcellus gas sales volumes for the year ended December 31, 2014 at an average gain of $0.21 per Mcf. For the year ended December 31, 2013, these financial hedges represented approximately 21.6 Bcf at an average gain of $0.81 per Mcf.

Total costs for the Marcellus segment were $321 million for the year ended December 31, 2014 compared to $172 million for the year ended December 31, 2013. The increase in total dollars and decrease in unit costs for the Marcellus segment were due to the following items:

•Marcellus lifting costs were $26 million for the year ended December 31, 2014 compared to $20 million for the year ended December 31, 2013. The increase in total dollars primarily relates to an increase in sales volumes, along with an increase in well tending costs, repair and maintenance costs, and costs related to wells operated by our joint-venture partners. The increase in total dollars was more than offset by the increase in gas sales volumes and resulted in an improvement in unit costs.

•Marcellus ad valorem, severance and other taxes were $17 million for the year ended December 31, 2014 compared to $9 million for the year ended December 31, 2013. The increase in total dollars was primarily due to an increase in severance tax expense caused by the 93.3% increase in gas and liquid sales volumes, changes in the mix of volumes produced by state as well as a 1.6% increase in average gas sales price, without the impact of hedging.

•Marcellus transportation, gathering, and compression costs were $110 million for the year ended December 31, 2014 compared to $50 million for the year ended December 31, 2013. Total dollars increased primarily due to the 93.3% increase in sales volumes which resulted in an increase in related party gathering fees, increased processing fees associated with NGLs, and an increase in utilized firm transportation expense. The impact on unit costs due to the increase in total dollars was offset, in part, by the increase in sales volumes.

•Marcellus direct administrative, selling and other costs were $36 million for the year ended December 31, 2014 compared to $26 million for the year ended December 31, 2013. Direct administrative, selling and other costs attributable to the total E&P division are allocated to the individual E&P segments based on a combination of capital, 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 decrease in unit costs was primarily due to the increase in volumes sold.

•Depreciation, depletion and amortization costs were $132 million for the year ended December 31, 2014 compared to $67 million for the year ended December 31, 2013. These amounts included depreciation on a per unit basis of $1.16 per Mcf and $1.14 per Mcf, respectively. The remaining depreciation, depletion and amortization costs were either recorded on a straight-line basis or related to gas well accretion.

UTICA GAS SEGMENT

The Utica segment had earnings before income tax of $41 million for the year ended December 31, 2014 compared to a loss before income tax of $4 million for the year ended December 31, 2013.

| | For the Years Ended December 31, | | | |
|---|---|---|---|---|
| | 2014 | 2013 | Variance | Percent Change |
| Utica Gas Sales Volumes (Bcf) | 10.2 | 0.5 | 9.7 | 1,940.0 % |
| NGL Sales Volumes (Bcfe)* | 4.6 | 0.1 | 4.5 | 4,500.0 % |
| Condensate Sales Volumes (Bcfe)* | 1.9 | 0.1 | 1.8 | 1,800.0 % |
| Total Utica Sales Volumes (Bcfe)* | 16.7 | 0.7 | 16.0 | 2,285.7 % |
| | | | | |
| Average Sales Price - Gas (Mcf) | $3.46 | $3.83 | $(0.37) | (9.7)% |
| Gain on Commodity Derivative Instruments - Cash Settlement- Gas (Mcf) | $0.12 | $— | $0.12 | 100.0 % |
| Average Sales Price - NGL (Mcfe)* | $6.39 | $6.09 | $0.30 | 4.9 % |
| Average Sales Price - Condensate (Mcfe)* | $11.69 | $12.78 | $(1.09) | (8.5)% |
| | | | | |
| Total Average Utica Sales Price (per Mcfe) | $5.27 | $5.80 | $(0.53) | (9.1)% |
| Average Utica Lifting Costs (per Mcfe) | 0.94 | 3.46 | (2.52) | (72.8)% |
| Average Utica Ad Valorem, Severance, and Other Taxes (per Mcfe) | 0.08 | (0.67) | 0.75 | 111.9 % |
| Average Utica Transportation, Gathering, and Compression Costs (per Mcfe) | 0.45 | 0.53 | (0.08) | (15.1)% |
| Average Utica Direct Administrative and Selling (per Mcfe) | 0.24 | 2.79 | (2.55) | (91.4)% |
| Average Utica Depreciation, Depletion and Amortization costs (per Mcfe) | 1.11 | 4.97 | (3.86) | (77.7)% |
| Total Average Utica Costs (per Mcfe) | $2.82 | $11.08 | $(8.26) | (74.5)% |
| Average Margin for Utica (per Mcfe) | $2.45 | $(5.28) | $7.73 | 146.4 % |

*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 Utica segment outside sales revenues were $87 million for the year ended December 31, 2014 compared to $4 million for the year ended December 31, 2013. The $83 million increase was primarily due to the 2,285.7% increase in total volumes sold, partially offset by a 9.1% decrease in total average sales price in the period-to-period comparison. The 16.0 Bcfe increase in sales volumes was primarily due to additional wells coming on-line from our ongoing drilling program. The decrease in Utica total average sales price was primarily the result of the $0.37 per Mcf decrease in gas market prices, along with a $0.28 per Mcfe decrease in the uplift related to NGLs and condensate.

During the fourth quarter of the 2014 period, a midstream company that handles and processes some of CONSOL Energy's gas and liquids had a fatality on one of their sites, during their operations. Over the course of the quarter CONSOL Energy elected to shut-in pads serviced by this midstream provider while safety processes and procedures were evaluated and validated. As a result of this process, it is estimated that the shut-in pads accounted for 2.7 Bcfe worth of lost production in the year ended December 31, 2014.

Total costs for the Utica segment were $47 million for the year ended December 31, 2014 compared to $8 million for the year ended December 31, 2013. The increase in total dollars and improvement in unit costs were all directly related to the 2,285.7% increase in total volumes sold, thus a per unit analysis of the Utica segment is not meaningful.

COALBED METHANE (CBM) GAS SEGMENT

The CBM segment had earnings before income tax of $92 million for the year ended December 31, 2014 compared to earnings before income tax of $81 million for the year ended December 31, 2013.

| | For the Years Ended December 31, | | | |
|---|---|---|---|---|
| | 2014 | 2013 | Variance | Percent Change |
| CBM Gas Sales Volumes (Bcf) | 79.5 | 82.9 | (3.4 ) | (4.1 )% |
| Average Sales Price - Gas (Mcf) | $4.32 | $3.69 | $0.63 | 17.1 % |
| Gain on Commodity Derivative Instruments - Cash Settlement- Gas (Mcf) | $0.05 | $0.40 | $(0.35 ) | (87.5 )% |
| Total Average CBM Sales Price (per Mcf) | $4.37 | $4.09 | $0.28 | 6.8 % |
| Average CBM Lifting Costs (per Mcf) | 0.45 | 0.42 | 0.03 | 7.1 % |
| Average CBM Ad Valorem, Severance, and Other Taxes (per Mcf) | 0.15 | 0.10 | 0.05 | 50.0 % |
| Average CBM Transportation, Gathering, and Compression Costs (per Mcf) | 1.35 | 1.37 | (0.02 ) | (1.5 )% |
| Average CBM Direct Administrative and Selling (per Mcf) | 0.13 | 0.10 | 0.03 | 30.0 % |
| Average CBM Depreciation, Depletion and Amortization Costs (per Mcf) | 1.14 | 1.12 | 0.02 | 1.8 % |
| Total Average CBM Costs (per Mcf) | $3.22 | $3.11 | $0.11 | 3.5 % |
| Average Margin for CBM (per Mcf) | $1.15 | $0.98 | $0.17 | 17.3 % |

The CBM segment outside sales revenues were $343 million for the year ended December 31, 2014 compared to $306 million for the year ended December 31, 2013. The $37 million increase was primarily due to a 6.8% increase in total average sales price offset, in part, by a 4.1% decrease in total volumes sold. CBM sales volumes decreased 3.4 Bcf for the year ended December 31, 2014 compared to the 2013 period. The decrease was primarily due to normal well declines without a corresponding offset of additional wells drilled since the Company's current focus is on Marcellus and Utica production. The decline in wells drilled was also due to the decline in coal production at our Buchanan Mine which resulted in fewer GOB collection wells being drilled.

The CBM total average sales price increased $0.28 per Mcf primarily due to a $0.63 per Mcf increase in market prices. The increase was offset, in part, by a $0.35 per Mcf decrease resulting from various transactions relating to our hedging program. These financial hedges represented approximately 70.0 Bcf of our produced CBM gas sales volumes for the year ended December 31, 2014 at an average gain of $0.06 per Mcf. For the year ended December 31, 2013, these financial hedges represented approximately 48.3 Bcf at an average gain of $0.69 per Mcf.

Total costs for the CBM segment were $255 million for the year ended December 31, 2014 compared to $258 million for the year ended December 31, 2013. The decrease in total dollars and increase in unit costs for the CBM segment were due to the following items:

•CBM lifting costs were $35 million for the year ended December 31, 2014 and December 31, 2013. The increase in unit costs was primarily due to the decrease in gas sales volumes.

•CBM ad valorem, severance and other taxes were $12 million for the year ended December 31, 2014 compared to $9 million for the year ended December 31, 2013. The increase of $3 million was due to an increase in severance tax expense resulting from the increase in average sales price, without the impact of hedging, as described above. Unit costs were also negatively impacted by the decrease in gas sales volumes.

•CBM transportation, gathering, and compression costs were $108 million for the year ended December 31, 2014 compared to $114 million for the year ended December 31, 2013. The decrease in total dollars and average per unit costs was due to lower utilized firm transportation expenses resulting primarily from the decrease in gas sales volumes. Improvements in unit costs were offset, in part, by the decrease in gas sales volumes.

•CBM direct administrative, selling and other costs were $10 million for the year ended December 31, 2014 compared to $8 million for the year ended December 31, 2013. Direct administrative, selling and other costs attributable to the total E&P division are allocated to the individual E&P segments based on a combination of capital and production. The $2 million increase in the period-to-period comparison was due to a larger portion of total direct administrative costs being allocated to the E&P segment over the Coal and Other segments. The $0.03 per Mcf increase in unit costs can be attributed to both an increase in total dollars allocated to the segment and a decline in gas sales volumes.

•Depreciation, depletion and amortization costs attributable to the CBM segment were $90 million for the year ended December 31, 2014 and $92 million for the year ended December 31, 2013. These amounts included depreciation on a per unit basis of $0.75 per Mcf and $0.77 per Mcf, respectively. The remaining depreciation, depletion and amortization costs were either recorded on a straight-line basis or related to gas well accretion.

OTHER GAS SEGMENT

The Other Gas segment had a loss before income tax of $95 million for the year ended December 31, 2014 compared to a loss before income tax of $159 million for the year ended December 31, 2013.

| | For the Years Ended December 31, | | | |
|---|---|---|---|---|
| | 2014 | 2013 | Variance | Percent Change |
| Other Gas Sales Volumes (Bcf) | 27.1 | 30.3 | (3.2) | (10.6)% |
| Oil Sales Volumes (Bcfe)* | 0.7 | 0.6 | 0.1 | 16.7% |
| Total Other Sales Volumes (Bcfe)* | 27.8 | 30.9 | (3.1) | (10.0)% |
| | | | | |
| Average Sales Price - Gas (Mcf) | $4.01 | $3.70 | $0.31 | 8.4% |
| Gain on Commodity Derivative Instruments - Cash Settlement- Gas (Mcf) | $0.11 | $0.81 | $(0.70) | (86.4)% |
| Average Sales Price - Oil (Mcfe)* | $14.81 | $14.78 | $0.03 | 0.2% |
| | | | | |
| Total Average Other Sales Price (per Mcfe) | $4.39 | $4.72 | $(0.33) | (7.0)% |
| Average Other Lifting Costs (per Mcfe) | 1.13 | 0.97 | 0.16 | 16.5% |
| Average Other Ad Valorem, Severance, and Other Taxes (per Mcfe) | 0.28 | 0.36 | (0.08) | (22.2)% |
| Average Other Transportation, Gathering, and Compression Costs (per Mcfe) | 1.21 | 1.19 | 0.02 | 1.7% |
| Average Other Direct Administrative and Selling (per Mcfe) | 0.19 | 0.41 | (0.22) | (53.7)% |
| Average Other Depreciation, Depletion and Amortization costs (per Mcfe) | 2.86 | 2.46 | 0.40 | 16.3% |
| Total Average Other Costs (per Mcfe) | $5.67 | $5.39 | $0.28 | 5.2% |
| Average Margin for Other (per Mcfe) | $(1.28) | $(0.67) | $(0.61) | (91.0)% |

*Oil is 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 and natural gas prices.

The Other Gas segment includes activity not assigned to the Marcellus, Utica, or CBM segments. This segment includes purchased gas activity, production royalty interest activity, exploration and other costs, other corporate expenses, and miscellaneous operational activity not assigned to a specific E&P division.

Other Gas sales volumes are primarily related to shallow oil and gas production as well as Upper Devonian Shale in Pennsylvania and West Virginia. Outside sales revenue from the Other Gas segment was approximately $120 million for the year ended December 31, 2014 compared to $121 million for the year ended December 31, 2013. Total costs related to these other sales were $162 million for the year ended December 31, 2014 compared to $170 million for the year ended December 31, 2013. The decrease in total volumes sold was primarily due to normal well declines which also had a negative impact on unit costs.

Production royalty interest gas sales represent the revenues related to the portion of production belonging to royalty interest owners sold by the CONSOL Energy E&P division. Production royalty interest gas sales revenue was $82 million for the year ended December 31, 2014 compared to $63 million for the year ended December 31, 2013. The increase in sales volumes, 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, | | | | |
|---|---|---|---|---|---|
| | 2014 | 2013 | Variance | Percent Change | |
| Production Royalty Interest Sales Volumes (in billion cubic feet) | 19.9 | 15.3 | 4.6 | 30.1 | % |
| Average Sales Price per thousand cubic feet | $4.14 | $4.13 | $0.01 | 0.2 | % |

Purchased gas sales volumes represent volumes of gas sold at market prices that were purchased from third-party producers. Purchased gas sales revenues were $9 million for the year ended December 31, 2014 compared to $7 million for the year ended December 31, 2013.

| | For the Years Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2014 | 2013 | Variance | Percent Change | |
| Purchased Gas Sales Volumes (in billion cubic feet) | 1.9 | 1.6 | 0.3 | 18.8 | % |
| Average Sales Price per thousand cubic feet | $4.65 | $4.12 | $0.53 | 12.9 | % |

Miscellaneous other income was $67 million for the year ended December 31, 2014 compared to $37 million for the year ended December 31, 2013. The $30 million increase was primarily due to the following items:

| | For the Years Ended December 31, | | | | | |
|---|---|---|---|---|---|---|
| | 2014 | 2013 | Variance | | Percent Change | |
| Gathering Revenue | $30 | $7 | $23 | | 328.6 | % |
| Equity in Earnings of Affiliates | 32 | 15 | 17 | | 113.3 | % |
| Interest Income | — | 13 | (13 | ) | (100.0 | )% |
| Other | 5 | 2 | 3 | | 150.0 | % |
| Total Miscellaneous Other Income | $67 | $37 | $30 | | 81.1 | % |

- Gathering revenue increased $23 million primarily due to an increase in revenue related to certain gathering arrangements.
- Earnings from our equity affiliates increased $17 million primarily due to an increase in earnings from CONE Midstream Partners, LP. See Note 27 - Related Party Transactions of the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.
- Interest income decreased $13 million primarily due to the 2013 collection of the final installment on the notes receivable from the 2011 Noble Energy joint venture transaction.
- The remaining $3 million increase relates to various transactions that occurred throughout both periods, none of which were individually material.

Gain on sale of assets was $46 million for the year ended December 31, 2014 compared to $21 million for the year ended December 31, 2013. The $25 million increase in the period-to-period comparison was primarily due to the sale of Utica rights in Marshall County, WV to Noble Energy, which closed in December 2014 and resulted in proceeds

and a pre-tax gain of $25 million.
General and administrative costs are allocated to the total E&P division based on percentage of total revenue and percentage of total projected capital expenditures. Costs were $64 million for the year ended December 31, 2014 compared to $39 million for the year ended December 31, 2013. Refer to discussion of total Company general and administrative costs contained in the section "Net Income Attributable to CONSOL Energy Shareholders" of this annual report for a detailed cost explanation.

Production royalty interest gas costs represent the costs related to the portion of production belonging to royalty interest owners sold by the CONSOL Energy E&P division. Production royalty interest gas costs were $70 million for the year ended December 31, 2014 compared to $53 million for the year ended December 31, 2013. The increase in sales volumes, 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, | | | | |
|---|---|---|---|---|---|
| | 2014 | 2013 | Variance | Percent Change | |
| Production Royalty Interest Sales Volumes (in billion cubic feet) | 19.9 | 15.3 | 4.6 | 30.1 | % |
| Average Cost per thousand cubic feet sold | $3.51 | $3.47 | $0.04 | 1.2 | % |

Purchased gas volumes represent volumes of gas purchased from third-party producers that we sell. Purchased gas volumes also reflect the impact of pipeline imbalances. The higher average cost per thousand cubic feet was due to overall price changes and contractual differences among customers in the period-to-period comparison. Purchased gas costs were $7 million for the year ended December 31, 2014 compared to $5 million for the year ended December 31, 2013.

| | For the Years Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2014 | 2013 | Variance | Percent Change | |
| Purchased Gas Volumes (in billion cubic feet) | 1.9 | 1.6 | 0.3 | 18.8 | % |
| Average Cost per thousand cubic feet sold | $3.75 | $3.05 | $0.70 | 23.0 | % |

Exploration and other costs were $23 million for the year ended December 31, 2014 compared to $61 million for the year ended December 31, 2013. The $38 million decrease in costs is primarily related to the following items:

| | For the Years Ended December 31, | | | | | |
|---|---|---|---|---|---|---|
| | 2014 | 2013 | Variance | | Percent Change | |
| Marcellus Title Defects | $— | $23 | $(23 | ) | (100.0 | )% |
| Dry Hole Expense | 2 | 9 | (7 | ) | (77.8 | )% |
| Lease Expiration Costs | 9 | 10 | (1 | ) | (10.0 | )% |
| Land Rentals | 5 | 6 | (1 | ) | (16.7 | )% |
| Seismic Activity | 4 | 2 | 2 | | 100.0 | % |
| Other | 3 | 11 | (8 | ) | (72.7 | )% |
| Total Exploration and Production Related Other Costs | $23 | $61 | $(38 | ) | (62.3 | )% |

- CONSOL Energy, working in collaboration with Noble Energy, conceded title defects on acreage which had a book value of $23 million for the year ended December 31, 2013.
- Dry hole costs decreased $7 million due to 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 lease term to expire because of unfavorable drilling economics. The $1 million decrease is due to various transactions that occurred throughout both periods, none of which were individually material.
- Land Rentals decreased $1 million in the period-to-period comparison due to various transactions that occurred throughout both periods, none of which were individually material.
- Seismic Activity increased $2 million due to various transactions that occurred throughout both periods, none of which were individually material.
-

Other expenses decreased $8 million due to various transactions that occurred throughout both periods, none of which were individually material.

Other corporate expenses related to the E&P division were $87 million for the year ended December 31, 2014 compared to $96 million for the year ended December 31, 2013. The $9 million decrease in the period-to-period comparison was made up of the following items:

| | For the Years Ended December 31, | | | |
|---|---|---|---|---|
| | 2014 | 2013 | Variance | Percent Change |
| Litigation Settlements | $(5) | $3 | $(8) | (266.7)% |
| Stock-based Compensation | 17 | 24 | (7) | (29.2)% |
| Bank Fees | 4 | 7 | (3) | (42.9)% |
| Unutilized Firm Transportation and Processing Fees | 38 | 36 | 2 | 5.6% |
| Short-term Incentive Compensation | 23 | 20 | 3 | 15.0% |
| Other | 10 | 6 | 4 | 66.7% |
| Total Other Corporate Expenses | $87 | $96 | $(9) | (9.4)% |

- Litigation settlements decreased $8 million due to various transactions that occurred throughout both periods, none of which were individually material.
- Stock-based compensation decreased $7 million in the period-to-period comparison primarily due to a reduction in non-cash amortization expense and less accelerated expense for retiree eligible employees under our current plans.
- Bank fees decreased $3 million due to various items that occurred throughout both periods, none of which were individually material.
- Unutilized firm transportation and processing fees represent pipeline transportation capacity the E&P segment has obtained to enable gas production to flow uninterrupted as sales volumes increase, as well as additional processing capacity for NGLs. The $2 million increase was primarily due to increased firm transportation capacity which has not been utilized by active operations.
- The short-term incentive compensation program is designed to increase compensation to eligible employees when CNX Gas reaches predetermined targets for, among other things, safety, production, compliance and unit costs. Short-term incentive compensation expense increased $3 million in the period-to-period comparison due to higher projected payouts.
- Other corporate related expenses increased $4 million due to various transactions that occurred throughout both periods, none of which were individually material.

Interest expense remained consistent at $9 million for the year ended December 31, 2014 and December 31, 2013. Interest was incurred by the Other Gas segment on the CNX Gas revolving credit facility along with interest allocated to the E&P segment under CONSOL Energy's credit facility, a capital lease and debt held by a variable interest entity.

TOTAL COAL DIVISION ANALYSIS for the year ended December 31, 2014 compared to the year ended December 31, 2013:

The coal division had earnings before income tax of $409 million for the year ended December 31, 2014 compared to earnings before income tax of $345 million for the year ended December 31, 2013. Variances by individual coal segment are discussed below.

| | For the Year Ended December 31, 2014 | | | | Difference to Year Ended December 31, 2013 | | | |
|---|---|---|---|---|---|---|---|---|
| | Pennsylvania Operations | Virginia Operations | Other Coal | Total Coal | Pennsylvania Operations | Virginia Operations | Other Coal | Total Coal |
| Coal Sales: | | | | | | | | |
| Produced Coal | $1,617 | $297 | $129 | $2,043 | $260 | $(153) | $(59) | $48 |
| Purchased Coal | — | — | 9 | 9 | — | — | (14) | (14) |
| Total Coal Sales | 1,617 | 297 | 138 | 2,052 | 260 | (153) | (73) | 34 |
| Other Outside Sales | — | — | 41 | 41 | — | — | (2) | (2) |
| Freight Revenue | 17 | 1 | 10 | 28 | (1) | (3) | (3) | (7) |
| Miscellaneous Other Income | | | | | | | | |