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

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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	As Received Heat Value(1) (Btu/lb) Range	Recoverable Reserves(2) Owned (%)	Recoverable Reserves(2) Leased (%)	Tons in Millions 12/31/2015	Tons in Millions 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.

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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.

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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 (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. 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 21st 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)%

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	38	—	101	139	32	(5)	51	78
Gain on Sale of Assets	1	—	28	29	1	(5)	(13)	(17)
Total Revenue and Other Income	1,673	298	318	2,289	292	(166)	(40)	86
Operating Costs and Expenses:								
Operating Costs	876	187	106	1,169	114	(64)	(25)	25
Direct Administrative and Selling	31	6	3	40	4	—	1	5
Total Royalty/Production Taxes	71	18	10	99	16	(8)	(8)	—
Depreciation, Depletion and Amortization	165	40	7	212	42	(3)	(9)	30
Total Operating Costs and Expenses	1,143	251	126	1,520	176	(75)	(41)	60
Other Costs and Expenses:								
Other Costs	8	6	141	155	(15)	(2)	—	(17)
Direct Administrative	1	—	3	4	—	—	(10)	(10)
Total Royalty/Production Taxes	—	—	2	2	—	—	(1)	(1)
Depreciation, Depletion and Amortization	8	8	52	68	7	(5)	(9)	(7)
Total Other Costs and Expenses	17	14	198	229	(8)	(7)	(20)	(35)
General and Administrative Expense	26	9	10	45	3	—	2	5
Other Corporate Expenses	39	9	7	55	1	(2)	—	(1)
Freight Expense	17	1	10	28	(1)	(3)	(3)	(7)

Related Party	—	3	—	3	—	—	—	—
Total Costs	1,242	287	351	1,880	171	(87)	(62)	22
Earnings (Loss) Before Income Taxes	$431	$ 11	$(33)	$409	$121	$ (79)	$22	$64

PENNSYLVANIA (PA) OPERATIONS COAL SEGMENT

The PA Operations coal segment principal activities are 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 are therefore not included in unit cost presentation. For the years ended December 31, 2014 and 2013 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 $431 million for the year ended December 31, 2014 compared to earnings before income tax of $310 million for the year ended December 31, 2013. PA Operations coal revenue and cost components on a per unit basis for these periods were as follows:

	For the Years Ended December 31,			
	2014	2013	Variance	Percent Change
Company Produced PA Operations Tons Sold (in millions)	26.1	21.2	4.9	23.1 %
Average Sales Price Per PA Operations Ton Sold	$61.88	$63.93	$(2.05)	(3.2 %)
Total Operating Costs Per Ton Sold	$33.50	$35.95	$(2.45)	(6.8 %)
Total Direct Administration and Selling Costs Per Ton Sold	1.20	1.26	(0.06)	(4.8 %)
Total Royalty/Production Taxes Per Ton Sold	2.71	2.58	0.13	5.0 %
Total Depreciation, Depletion and Amortization Costs Per Ton Sold	6.34	5.76	0.58	10.1 %
Total Costs Per PA Operations Ton Sold	$43.75	$45.55	$(1.80)	(4.0 %)
Average Margin Per PA Operations Ton Sold	$18.13	$18.38	$(0.25)	(1.4 %)

Coal Sales

PA Operations produced coal outside sales revenues were $1,617 million for the year ended December 31, 2014 compared to $1,357 million for the year ended December 31, 2013. The $260 million increase was attributable to 4.9 million additional tons sold in the 2014 period partially offset by a $2.05 per ton lower average sales price. The lower average PA Operations coal sales price in the 2014 period was the result of the roll-off of some higher-priced legacy sales contracts. The PA Operations coal segment revenue was also impacted by 3.3 million tons of PA Operations coal being priced on the export market for the year ended December 31, 2014, which was 0.8 million tons lower than the tons sold in the year ended December 31, 2013.

Freight Revenue

Freight revenue is the amount billed to customers for transportation costs incurred. This revenue is based on weight of coal shipped, negotiated freight rates and method of transportation (i.e. rail) used by the customers to which CONSOL Energy contractually provides transportation services. Freight revenue is completely offset in freight expense. Freight revenue was $17 million for the year ended December 31, 2014 compared to $18 million for the year ended December 31, 2013. 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 $38 million for the year ended December 31, 2014 compared to $6 million for the year ended December 31, 2013. The $32 million increase was due to the following items:

	For the Years Ended December 31,		
	2014	2013	Variance
Coal Contract Buyout	$30	$—	$30
Rental/Royalty Income	3	1	2

Business Interruption Proceeds- Bailey Mine Belt	—	5	(5)
Other	5	—	5
Total Miscellaneous Other Income	$38	$6	$32

- For the year ended December 31, 2014, $30 million of income was related to a coal customer contract buyout. The discontinued contract was a long term contract that created pricing risks for both parties. The parties agreed to an amicable settlement. No such transactions were entered into in the year ended December 31, 2013.
- Rental/Royalty income increased $2 million due to various transactions that occurred throughout both periods, none of which were individually material.
- Business interruption proceeds of $5 million were received in the prior year-to-date period related to the 2012 Bailey Mine Conveyor Belt accident.
- Other income increased $5 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 $1 million due to various transactions that occurred throughout both periods, none of which were individually material.

Cost of Coal Sold

Total operating costs and expenses is comprised of changes in PA Operations coal inventory, both volumes and carrying values, and costs of tons sold in the period. The costs per ton sold include items such as direct operating costs, royalty and production taxes, direct administration and selling, and depreciation, depletion, and amortization costs. Total operating costs and expenses for PA Operations were $1,143 million for the year ended December 31, 2014, or $176 million higher than the $967 million for the year ended December 31, 2013. Total costs per PA Operations ton sold was $43.75 per ton in the year ended December 31, 2014 compared to $45.55 per ton in the year ended December 31, 2013. The increase in total dollars and decrease in unit costs was primarily due to the 23.1% increase in PA Operations tons sold. Fixed costs are allocated over more tons, resulting in lower unit costs. These improvements were offset, in part, by various maintenance projects related to additional longwall overhauls and twenty-two thousand additional continuous miner feet mined at both Bailey Mine and Enlow Fork Mine. The additional continuous miner footage resulted in additional roof support, haulage, and mine maintenance costs. Unit costs were also negatively impacted in the current period due to adverse geological conditions at Enlow Fork Mine and Harvey Mine along with equipment issues at Harvey Mine.

Other Costs And Expenses

Other costs is comprised of various costs and expenses that are assigned to the PA Operations coal segment but not allocated to each individual mine and therefore not included in unit costs. Other costs were $8 million for the year ended December 31, 2014 compared to $23 million for the year ended December 31, 2013. The change is due to the following items:

	For the Years Ended December 31,		
	2014	2013	Variance
Supplies Expense	$3	$9	$(6)
Property and Other Taxes	2	2	—
Other	3	12	(9)
Total Other Costs	$8	$23	$(15)

- Supplies expense decreased $6 million primarily due to the prior year-to-date period including additional supplies needed for repairs related to the 2012 Bailey Mine Belt Conveyor accident which was not included in active mining costs.
- Property and other taxes remained consistent in the period-to-period comparison.
- Other expense decreased $9 million due to various items that occurred throughout both periods, none of which were individually material.

Direct administrative expense is primarily made up of labor and benefits and consulting expenses that were allocated to the Harvey Mine while it was in development phase prior to March 2014. The amount of direct administrative expense allocated to the PA Operations coal segment remained consistent in the period-to-period comparison.

Depreciation, depletion, and amortization increased $7 million primarily due to additional assets placed in service in the period-to-period comparison.

General and Administrative Expense

General and administrative costs are allocated to each coal segment based upon the activity at the segment determined by their level of operating activity. The amount of general and administrative costs allocated to PA Operations was $26 million for the year ended December 31, 2014 compared to $23 million for the year ended December 31, 2013. Refer to the 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.

Other Corporate Expense

Other corporate expense is made up of expenses for stock based compensation and the short-term incentive compensation program. These expenses are made up of costs that are directly related to each coal segment along with a portion of costs that are allocated to each segment based on a percent of total labor dollars. For the year ended December 31, 2014 other corporate expenses were $39 million compared to $38 million for the year ended December 31, 2013. The increase of $1 million was primarily due to PA Operations representing a larger portion of total coal labor dollars.

Freight Expense

Freight expense is based on weight of coal shipped, negotiated freight rates and method of transportation (i.e. 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. The $1 million decrease in freight expense was due to decreased shipments under contracts which CONSOL Energy contractually provides transportation services.

VIRGINIA (VA) OPERATIONS COAL SEGMENT

The VA Operations coal segment principal activities are mining, preparation and marketing of low 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 are therefore not included in unit cost presentation. For the years ended December 31, 2014 and 2013 the segment included the following mines: Buchanan Mine, Amonate Complex and the corresponding preparation plant facilities. Operations at Amonate Complex were idled in September 2012, but the complex continued to sell coal inventory in 2013.

The VA Operations coal segment had earnings before income tax of $11 million for the year ended December 31, 2014 compared to earnings before income tax of $90 million for the year ended December 31, 2013. The VA Operations coal revenue and cost components on a per unit basis for these periods were as follows:

	For the Years Ended December 31,			
	2014	2013	Variance	Percent Change
Company Produced VA Operations Tons Sold (in millions)	4.1	4.9	(0.8)	(16.3%)
Average Sales Price Per VA Operations Ton Sold	$71.80	$92.43	$(20.63)	(22.3%)
Total Operating Costs Per Ton Sold	$44.94	$51.18	$(6.24)	(12.2%)
Total Direct Administrative and Selling Costs Per Ton Sold	1.42	1.29	0.13	10.1%
Total Royalty/Production Taxes Per Ton Sold	4.45	5.65	(1.20)	(21.2%)
Total Depreciation, Depletion and Amortization Costs Per Ton Sold	9.86	8.87	0.99	11.2%
Total Costs Per VA Operations Ton Sold	$60.67	$66.99	$(6.32)	(9.4%)
Average Margin Per VA Operations Ton Sold	$11.13	$25.44	$(14.31)	(56.3%)

Coal Sales

VA Operations produced coal outside sales revenues were $297 million for the year ended December 31, 2014 compared to $450 million for the year ended December 31, 2013. The $153 million decrease was attributable to a $20.63 per ton lower average sales price and a 0.8 million decrease in tons sold. The average sales price per VA Operations ton sold decreased in the period-to-period comparison due to the weakening in the global metallurgical coal market. The VA Operations coal segment revenue was also impacted by 3.1 million tons of VA Operations coal being priced on the export market for the year ended December 31, 2014, which was 0.7 million tons lower than the tons sold in the year ended December 31, 2013.

Freight Revenue

Freight revenue was $1 million for the year ended December 31, 2014 compared to $4 million for the year ended December 31, 2013. The $3 million decrease in freight revenue was due to decreased shipments where CONSOL Energy contractually provides transportation services.

Miscellaneous Other Income

Miscellaneous other income decreased $5 million in the period-to-period 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 decreased $5 million in the period-to-period comparison primarily due to various asset sales in the year ended December 31, 2013. No such transactions occurred in the year ended December 31, 2014.

Cost of Coal Sold

Total operating costs and expenses for VA Operations were $251 million for the year ended December 31, 2014, or $75 million lower than the $326 million for the year ended December 31, 2013. Total costs per VA Operations ton sold were $60.67 per ton in the year ended December 31, 2014 compared to $66.99 per ton in the year ended December 31, 2013. The decrease in total dollars and unit costs per VA Operations ton sold was primarily due to lower royalty and production taxes, lower wage and wage related expenses, and a reduction in the number of degas wells drilled. The decreases were related to lower average sales prices and cost control measures that were implemented due to the weak metallurgical coal market. Part of the cost control measures included a decrease in operating shifts at the Buchanan Mine. The mine went from three operating shifts to two operating shifts beginning in May 2014. These improvements were offset, in part, by lower tons sold.

Other Costs And Expenses

Total other costs for VA Operations were $6 million for the year ended December 31, 2014 compared to $8 million for the year ended December 31, 2013. The $2 million decrease was due to the following items:

	For the Years Ended December 31,		
	2014	2013	Variance
Idle Mine Costs	$6	$6	$—
Other	—	2	(2)
Total Other Costs	$6	$8	$(2)

- Idle mine costs are costs related to the temporary idling of the Amonate Complex which remained consistent year over year.
- Other expense decreased $2 million due to various transactions that occurred throughout both periods, none of which were individually material.

Depreciation, depletion, and amortization decreased $5 million primarily due to a decrease in assets placed in service in the period-to-period comparison.

General and Administrative Expense

General and administrative costs allocated to the VA Operations coal segment were $9 million for both years ended December 31, 2014 and December 31, 2013. Refer to the 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.

Other Corporate Expense

For the year ended December 31, 2014 other corporate expenses were $9 million compared to $11 million for the year ended December 31, 2013. The decrease of $2 was primarily related to VA Operations representing a smaller portion of total coal labor dollars which is the basis of the allocation.

Freight Expense

Freight expense decreased $3 million in the period-to-period comparison due to decreased shipments under contracts which CONSOL Energy contractually provides transportation services.

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, 2014 and 2013 the segment included the Miller Creek Complex.

The Other coal segment had a loss before income tax of $33 million for the year ended December 31, 2014 compared to a loss before income tax of $55 million for the year ended December 31, 2013. Other coal revenue and cost components on a per unit basis for these periods were as follows:

	For the Years Ended December 31,			
	2014	2013	Variance	Percent Change
Company Produced Other Operations Tons Sold (in millions)	2.2	2.7	(0.5)	(18.5%)
Average Sales Price Per Other Operations Ton Sold	$60.12	$70.22	$(10.10)	(14.4%)
Total Operating Costs Per Ton Sold	$48.95	$47.29	$1.66	3.5%
Total Direct Administration and Selling Costs Per Ton Sold	1.14	0.53	0.61	115.1%
Total Royalty/Production Taxes Per Ton Sold	5.12	8.05	(2.93)	(36.4%)
Total Depreciation, Depletion and Amortization Costs Per Ton Sold	3.62	6.89	(3.27)	(47.5%)
Total Costs Per Other Operations Ton Sold	$58.83	$62.76	$(3.93)	(6.3%)
Average Margin Per Other Operations Ton Sold	$1.29	$7.46	$(6.17)	(82.7%)

Coal Sales

Other produced coal outside sales revenues were $129 million for the year ended December 31, 2014 compared to $188 million for the year ended December 31, 2013. The $59 million decrease was attributable to a 0.5 million decrease in tons sold in 2014 and a $10.10 lower average sales price per ton sold. The lower average coal sales price in the 2014 period was the result of the roll-off of some higher-priced legacy sales contracts.

Purchased coal sales consist of revenues from processing third-party coal in our preparation plants for blending purposes to meet customer coal specifications and coal purchased from third parties and sold directly to our customers. The revenues were $9 million for the year ended December 31, 2014 compared to $23 million for the year ended December 31, 2013. The $14 million decrease in the period-to-period comparison was due to lower volumes of coal that needed to be purchased to fulfill various contracts.

Other Outside Sales Revenue

Other outside sales revenue for the Other coal segment consist of revenues from our coal terminal operations. Coal terminal operations sales revenues decreased $2 million in the period-to-period comparison primarily due to a decrease in thru-put volumes in the current year.

Freight Revenue

Freight revenue was $10 million for the year ended December 31, 2014 compared to $13 million for the year ended December 31, 2013. The $3 million decrease in freight revenue was due to decreased shipments under which CONSOL Energy contractually provides transportation services.

Miscellaneous Other Income

Miscellaneous other income was $101 million for the year ended December 31, 2014 compared to $50 million for the year ended December 31, 2013. The $51 million increase was due to the following items:

	For the Years Ended December 31,		
	2014	2013	Variance
Rental Income	$42	$1	$41
Blacksville Fire Settlement	10	—	10
Royalty Income	20	17	3
Right of Way Sales	7	5	2
Equity in Earnings of Affiliates	19	18	1
Other	3	9	(6)
Total Miscellaneous Other Income	$101	$50	$51

- Rental income increased $41 million primarily due to equipment subleased to a third-party. These arrangements began in December 2013.
- During the year ended December 31, 2014, $10 million of insurance proceeds were received related to the Blacksville No. 2 Mine fire that occurred in March 2013.
- Royalty income increased $3 million due to various transactions that occurred throughout both periods, none of which were individually material.
- Land rental income primarily consists of income related to the sale of right of ways on property that CONSOL Energy owns. The $2 million increase was due to an increase in land activity in the period-to-period comparison.
- Equity in earnings of affiliates increased $1 million due to various transactions completed by our equity partners, none of which were individually material.
- Other decreased $6 million due to various activities that occurred in the current period, none of which were individually material.

Gain on Sale of Assets

Gain on sale of assets was $28 million for the year ended December 31, 2014 compared to $41 million for the year ended December 31, 2013. The decrease of $13 million was primarily due to various asset sales that occurred in both periods. 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 information.

Cost of Coal Sold

Total cost of coal sold attributable to the Other coal segment was $126 million for the year ended December 31, 2014, or $41 million lower than the $167 million for the year ended December 31, 2013. Total costs per Other Operations ton sold were $58.83 for the year ended December 31, 2014, compared to $62.76 per ton for the year ended December 31, 2013. 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 Coal segment total other costs were $141 million for the years ended December 31, 2014 and 2013. The breakout for both periods is as follows:

	For the Years Ended December 31,		
	2014	2013	Variance
Purchased Coal	$13	$41	$(28)
Closed and Idle Mines	36	44	(8)
Coal Terminal Operations	25	30	(5)
Coal Reserve Holding Costs	10	5	5
Lease Rental Expense	30	—	30
Other	27	21	6
Total Other Costs	$141	$141	$—

- Purchased coal costs decreased $28 million due to lower volumes of coal that needed to be purchased to fulfill various contracts.
- Closed and idle mine costs decreased approximately $8 million for the year ended December 31, 2014 compared to the year ended December 31, 2013. This was primarily due to changes in the Company's perpetual care liability at the Fola Mining Complex and changes in the operational status of various mines, between idled and operating throughout both periods, none of which were individually material.
- Coal terminal operations costs decreased $5 million due to decreased thru-put volumes in the current year.
- Coal reserve holding costs which primarily consists of property and other taxes, increased $5 million due to various transactions that occurred throughout both periods, none of which were individually material.
- Lease rental expense increased $30 million primarily due to equipment leases that were subleased to a third-party. The third-party subleases began in December 2013.
- Other expenses related to the Other coal segment increased $6 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 is primarily made up of labor and benefits and consulting expenses that relate to coal terminal operations and idle mine locations. Direct administrative expense decreased $10 million in the period-to-period comparison due to less resources being allocated to idle mine locations in the current period.

Royalty and production taxes decreased $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 $9 million primarily due to a $14 million decrease in the asset retirement obligation at the Fola Mining Complex. The decrease was offset, in part, by additional assets placed in service in the period-to-period comparison.

General and Administrative Expense

General and administrative costs allocated to the Other Coal segment were $10 million for the year ended December 31, 2014 compared to $8 million for the year ended December 31, 2013. Refer to the 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.

Other Corporate Expense

For the years ended December 31, 2014 and 2013, other corporate expenses remained consistent at $7 million.

Freight Expense

Freight expense decreased $3 million in the period-to-period comparison due to decreased shipments where CONSOL Energy contractually provides transportation services.

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

The Other division includes various corporate activities that are not allocated to the E&P or Coal divisions and activity from the sales of industrial supplies (this subsidiary was sold in December 2014). The Other division had a loss before income tax from continuing operations of $416 million for the year ended December 31, 2014 compared to a loss before income tax from continuing operations of $297 million for the year ended December 31, 2013. The Other division also includes total company income tax expense of $14 million for the year ended December 31, 2014 compared to an income tax benefit of $33 million for the year ended December 31, 2013.

	For the Years Ended December 31,			
	2014	2013	Variance	Percent Change
Other Outside Sales	$235	$217	$18	8.3 %
Loss on Sale of Assets	(31)	—	(31)	(100.0)%
Miscellaneous Other Income	2	15	(13)	(86.7)%
Total Revenue	206	232	(26)	(11.2)%
Miscellaneous Operating Expense	310	315	(5)	(1.6)%
Depreciation, Depletion & Amortization	2	3	(1)	(33.3)%
Loss on Debt Extinguishment	95	—	95	100.0 %
Interest Expense	215	211	4	1.9 %
Total Other Costs	622	529	93	17.6 %
Loss Before Income Tax from Continuing Operations	(416)	(297)	(119)	(40.1)%
Income Tax	14	(33)	47	142.4 %
Net Loss from Continuing Operations	$(430)	$(264)	$(166)	(62.9)%

Outside Sales

Outside sales revenue from the other division was $235 million for the year ended December 31, 2014 compared to $217 million for the year ended December 31, 2013. The increase was related to higher sales volumes from our industrial supplies subsidiary which was sold 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.

Loss on Sale of Assets

The loss on sale of assets of $31 million was related to the divestiture of the Company's industrial supplies subsidiary in December 2014. No such transactions occurred in the prior period.

Miscellaneous Other Income

Miscellaneous other income of $2 million was recognized for the year ended December 31, 2014 compared to $15 million for the year ended December 31, 2013. The $13 million decrease was primarily due to the following items:

	For the Years Ended December 31,		
	2014	2013	Variance
Pennsylvania Turnpike Settlement	$—	$9	$(9)
Interest Income	2	4	(2)
Equity in Earnings of Affiliates	(1)	1	(2)
Other	1	1	—
Total Miscellaneous Other Income	$2	$15	$(13)

- Pennsylvania turnpike settlement relates to mediation with the PA Turnpike Commission that was settled for $9 million in 2013.

- Interest income decreased $2 million in the period-to-period comparison due to various transactions that occurred throughout both periods, none of which were individually material.
- Equity in earnings of affiliates decreased $2 million in the period-to-period comparison due to various transactions that occurred throughout both periods, none of which were individually material.

- Other remained consistent in the period-to-period comparison.

Miscellaneous Operating Expense

Miscellaneous operating expense related to the Other division was $310 million for the year ended December 31, 2014 compared to $315 million for the year ended December 31, 2013. The $5 million increase was due to the following items:

	For the Years Ended December 31,		
	2014	2013	Variance
Industrial Supplies	$231	$215	$16
Long-Term Liability Plan Changes	10	—	10
Revolver Modification Fees	3	—	3
Bank Fees	19	18	1
Corporate Initiative Fees and Other Legal Charges	10	15	(5)
Pension Settlement	29	39	(10)
CNX Gas Shareholder Settlement	—	20	(20)
Other	8	8	—
Miscellaneous Operating Expense	$310	$315	$(5)

- Industrial supplies expense represent costs from our industrial supplies subsidiary which was sold 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. The $16 million increase in expense was due to higher sales volumes in the current period along with various changes in inventory costs, none of which were individually material.
- 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. 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.
- Revolver modification fees resulted in a $3 million acceleration of previously deferred financing fees. No such transactions occurred in the prior period.
- Bank fees increased $1 million primarily due to various transactions that occurred throughout both periods, none of which were individually material.
- 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 our joint venture partners and the CNX Gas shareholder settlement case. The $5 million decrease was due to various transactions that occurred in 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 the 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 Post-Employment Benefit Plans in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional detail.
- The CNX Gas shareholder settlement was the result of an agreement for resolution of the class actions brought by shareholders of CNX Gas challenging the tender offer by CONSOL Energy to acquire all of the shares of CNX Gas common stock that CONSOL Energy did not already own for $38.25 per share in May 2010. The total settlement provided for payment to the plaintiffs of $43 million, of which the Company's portion was $20 million.
- Other remained consistent in the period-to-period comparison.

Depreciation, Depletion & Amortization

Deprecation, depletion, & amortization decreased $1 million in the period-to-period comparison due to various transactions that occurred throughout both periods, none of which were individually material.

Loss on Debt Extinguishment

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 price equal to 104.0% of the principal amount, and the partial purchase of the 8.25% senior notes that were due in 2020 at an average price equal to 107.5% of the principal amount. No such transactions occurred in the prior period.

Interest Expense

Interest Expense increased $4 million in the period-to-period comparison primarily due to the decrease in capitalized interest related to the Harvey Mine going into production in 2014. The increase was offset, in part, by the IRS audit resolution causing a reduction to anticipated interest (See Note 7 - Income Taxes of the Notes to the Audited Consolidated Financial Statements of this Form 10-K), the early payoff of the 2017 bonds and partial purchase of the 2020 bonds. The decrease was also related to the bonds, due 2022, issued in April 2014 and August 2014 which have a lower interest rate than the 2017 and the 2020 bonds.

Income Taxes

The effective income tax rate from continuing operations was 7.8% for the year ended December 31, 2014 compared to (72.0)% for the year ended December 31, 2013. The effective rates for the years ended December 31, 2014 and 2013 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, 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 related to increased percentage depletion deductions, offset, in part, by $1 million of tax expense due to changes in the Domestic Production Activities Deduction. 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 depletion by $7 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.

	For the Years Ended December 31,			
	2014	2013	Variance	Percent Change
Total Company Earnings Before Income Tax	$183	$46	$137	297.3 %
Income Tax Expense	$14	$(33)	$47	(141.6)%
Effective Income Tax Rate	7.8 %	(72.0)%	79.8 %	

Critical Accounting Policies

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make judgments, estimates and assumptions that affect reported amounts of assets and liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities in the Consolidated Financial Statements and at the date of the financial statements. See Note 1-Significant Accounting Policies in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for further discussion. We base our estimates on historical experience and on various other assumptions that we believe are reasonable under the circumstances, the results of which form the basis for making the judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. We evaluate our estimates on an on-going basis. Actual results could differ from those estimates upon subsequent resolution of identified matters. Management believes that the estimates utilized are reasonable. The following critical accounting policies are materially impacted by judgments, assumptions and estimates used in the preparation of the Consolidated Financial Statements.

Other Post Employment Benefits (OPEB), Salaried Pensions, Workers' Compensation and Coal Workers' Pneumoconiosis (CWP)

Liabilities and expenses for OPEB, pension, workers' compensation and CWP are determined using actuarial methodologies and incorporate significant assumptions, including the interest rate used to discount the future estimated liability, the expected long-term rate of return on plan assets, and several assumptions relating to the employee workforce (salary increases, health care cost trend rates, retirement age, and mortality).

The interest rate used to discount future estimated liabilities is determined using a Company-specific yield curve model (above-mean) developed with the assistance of an external actuary. The Company-specific yield curve uses a subset of the expanded bond universe to determine the Company-specific discount rate. Bonds used in the yield curve are rated AA by Moody's or Standard & Poor's as of the measurement date. The yield curve model parallels the plans' projected cash flows.

The assumed rate of return on plan assets can also impact CONSOL Energy's pension liability. The market related asset value is derived by taking the cost value of assets as of December 31, 2015 and multiplying it by the average 36-month ratio of the market value of assets to the cost value of assets. CONSOL Energy's pension plan weighted average asset allocations at December 31, 2015 consisted of 50% equity securities and 50% debt securities.

The estimated liabilities recognized at December 31, 2015 and the benefit payments made for the year end December 31, 2015 were as follows:

Plan	Estimated Liability as of December 31, 2015	Benefit Payments for the year ended December 31, 2015
OPEB	$671,755	$58,378
Pension	$94,368	$9,053
Workers' Compensation	$83,165	$18,999
CWP	$122,503	$10,113

Reclamation, Mine Closure and Gas Well Closing Obligations

The Surface Mining Control and Reclamation Act established operational, reclamation and closure standards for all aspects of surface mining as well as most aspects of deep mining. CONSOL Energy accrues for the costs of current coal mine disturbance and final coal mine and gas well closure, including the cost of treating mine water discharge where necessary. Estimates of our total reclamation, mine-closing, and gas well closing liabilities which are based upon permit requirements and CONSOL Energy engineering expertise related to these requirements, including the current portion, were approximately $549.6 million at December 31, 2015. This liability is reviewed annually, or when events and circumstances indicate an adjustment is necessary, by CONSOL Energy management and engineers. The estimated liability can significantly change if actual costs vary from assumptions or if governmental regulations change significantly.

Accounting for Asset Retirement Obligations requires that the fair value of an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. The present value of the estimated asset retirement costs is capitalized as part of the carrying amount of the long-lived asset. Asset retirement obligations primarily relate to the closure of mines and gas wells and the reclamation of land upon exhaustion of coal and gas reserves. Changes in the variables used to calculate the liabilities can have a significant effect on the mine closing, reclamation and gas well closing liabilities. The amounts of assets and liabilities recorded are dependent upon a number of variables, including the estimated future retirement

costs, estimated proved reserves, assumptions involving profit margins, inflation rates, and the assumed credit-adjusted risk-free interest rate.

Accounting for Asset Retirement Obligations also requires depreciation of the capitalized asset retirement cost and accretion of the asset retirement obligation over time. The depreciation will generally be determined on a units-of-production basis, whereas the accretion to be recognized will escalate over the life of the producing assets, typically as production declines.

Income Taxes

Deferred tax assets and liabilities are recognized using enacted tax rates for the estimated future tax effects of temporary differences between the book and tax basis of recorded assets and liabilities. Deferred tax assets are reduced by a valuation allowance if it is more likely than not that some portion of the 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. At December 31, 2015, CONSOL Energy has deferred tax liabilities in excess of deferred tax assets of approximately $75 million. At December 31, 2015, CONSOL Energy had a valuation allowance of $71 million on deferred tax assets.

CONSOL Energy evaluates all tax positions taken on the state and federal tax filings to determine if the position is more likely than not to be sustained upon examination. For positions that meet the more likely than not to be sustained criteria, an evaluation to determine the largest amount of benefit, determined on a cumulative probability basis that is more likely than not to be realized upon ultimate settlement is determined. A previously recognized tax position is reversed when it is subsequently determined that a tax position no longer meets the more likely than not threshold to be sustained. The evaluation of the sustainability of a tax position and the probable amount that is more likely than not is based on judgment, historical experience and on various other assumptions that we believe are reasonable under the circumstances. The results of these estimates, that are not readily apparent from other sources, form the basis for recognizing an uncertain tax liability. Actual results could differ from those estimates upon subsequent resolution of identified matters. CONSOL Energy has $8 million of uncertain tax liabilities at December 31, 2015.

Stock-Based Compensation

As of December 31, 2015, we have issued five types of share-based payment awards: options, restricted stock units, performance stock options, performance share units, and CONSOL stock units.

The fair value of each restricted stock unit awarded is equivalent to the closing market price of a share of the Company's stock on the date of the grant. The fair value of each performance share unit is determined by the underlying share price of our company stock on the date of the grant for the performance shares and a Monte Carlo simulation method for the market share portion of the award. The fair value of each CONSOL stock unit was determined by the Monte Carlo simulation as well. All outstanding options and performance stock options are fully vested.

As of December 31, 2015, $26,109 of total unrecognized compensation cost related to unvested awards is expected to be recognized over a weighted-average period of 1.74 years. See Note 19 - Stock-based Compensation in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for more information.

Contingencies

CONSOL Energy is currently involved in certain legal proceedings. We have accrued our estimate of the probable costs for the resolution of these claims. This estimate has been developed in consultation with legal counsel involved

in the defense of these matters and is based upon the nature of the lawsuit, progress of the case in court, view of legal counsel, prior experience in similar matters, and management's intended response. Future results of operations for any particular quarter or annual period could be materially affected by changes in our assumptions or the outcome of these proceedings. Legal fees associated with defending these various lawsuits and claims are expensed when incurred. 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 more information.

Derivative Instruments

CONSOL Energy enters into financial derivative instruments to manage exposure to natural gas and oil price volatility. We measure every derivative instrument at fair value and record them on the balance sheet as either an asset or liability. Changes in fair value of derivatives are recorded currently in earnings unless special hedge accounting criteria are met. For derivatives designated as fair value hedges, the changes in fair value of both the derivative instrument and the hedged item are recorded in earnings. For derivatives designated as cash flow hedges, the effective portions of changes in fair value of the derivative are

reported in other comprehensive income or loss and reclassified into earnings in the same period or periods which the forecasted transaction affects earnings. The ineffective portions of hedges are recognized in earnings in the current year. CONSOL Energy currently utilizes only cash flow hedges that are considered highly effective.

CONSOL Energy formally assesses, both at inception of the hedge and on an ongoing basis, whether each derivative is highly effective in offsetting changes in fair values or cash flows of the hedge item. If it is determined that a derivative is not highly effective as a hedge or if a derivative ceases to be a highly effective hedge, CONSOL Energy will discontinue hedge accounting prospectively.

On December 31, 2014, CONSOL Energy de-designated all of its derivative positions as hedging instruments. Subsequent changes in fair value will be recorded in current earnings. Deferred gains and losses in other comprehensive income as of that date will be recorded in earnings when the related physical transaction occurs or when it is determined that the physical transaction is no longer probable of occurring.

Natural Gas and Coal Reserve Values

There are numerous uncertainties inherent in estimating quantities and values of economically recoverable natural gas and coal reserves, including many factors beyond our control. As a result, estimates of economically recoverable natural gas and 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. Our natural gas reserves are reviewed by independent experts each year. Our coal reserves are periodically reviewed by an independent third party consultant. Some of the factors and assumptions which impact economically recoverable reserve estimates include:

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

Each of these factors may in fact vary considerably from the assumptions used in estimating reserves. For these reasons, estimates of the economically recoverable quantities of gas and coal attributable to a particular group of properties, and classifications of these reserves based on risk of recovery and estimates of future net cash flows, may vary substantially. Actual production, revenues and expenditures with respect to our reserves will likely vary from estimates, and these variances may be material. See "Risk Factors" in Item 1A of this report for a discussion of the uncertainties in estimating our reserves.

CONSOL Energy performs a quantitative annual impairment test, during the fourth quarter of each year, over proved properties using the published NYMEX forward prices, timing, methods and other assumptions consistent with historical periods. During interim periods, management updates these annual tests whenever events or changes in circumstances indicate that a property’s carrying amount may not be recoverable. Throughout the first six months of 2015, spot prices and forward curves for natural gas continued to decline from December 31, 2014 prices, which together with other macro-economic factors in the exploration and production industry were deemed indicators of impairment for all of the Company's natural gas assets. Impairment tests require that the Company first compare future undiscounted cash flows by asset group to their respective carrying values. If the carrying amount exceeds the estimated undiscounted future cash flows, a reduction of the carrying amount of the natural gas properties to their estimated fair values is required, which is determined based on discounted cash flow techniques using a market-specific weighted average cost of capital. During the quarter ended June 30, 2015, certain of the Company’s producing gas properties, primarily shallow oil and gas assets, failed the undiscounted cash flow portion of the test.

After performing the discounted cash flow portion of the test, CONSOL Energy recorded an impairment of $824,742 in the Impairment of Exploration and Production Properties in the Consolidated Statement of Income. See Note 1 - Significant Accounting Policies in Item 8 of this Form 10-K for more information.

Liquidity and Capital Resources

CONSOL Energy generally has satisfied its working capital requirements and funded its capital expenditures and debt service obligations with cash generated from operations and proceeds from borrowings. In June 2014, CONSOL Energy entered into a Credit Agreement for a $2.0 billion senior secured revolving credit facility. In November 2015, the Company’s lending group reaffirmed the borrowing base of the facility. This Agreement expires on June 18, 2019. The facility is secured by substantially all of the assets of CONSOL Energy and certain of its subsidiaries. CONSOL Energy's credit facility allows for up to $2.0 billion of borrowings, which includes $750 million letters of credit aggregate sub-limit. CONSOL Energy can also request an additional $500 million increase in the aggregate borrowing limit amount. Fees and interest rate spreads are based on the percentage of facility utilization, measured quarterly. Availability under the facility is limited to a borrowing base, which is determined by the lenders syndication agent and approved by the required number of lenders in good faith by calculating a value of CONSOL Energy's proved natural gas reserves. The facility includes a minimum interest coverage ratio covenant of no less than 2.50 to 1.00, measured quarterly. The interest coverage ratio is calculated as the ratio of Adjusted EBITDA to cash interest expense of CONSOL Energy and certain of its subsidiaries excluding CNXC. The interest coverage ratio was 5.32 to 1.00 at December 31, 2015. Adjusted EBITDA, as used in the covenant calculation, excludes non-cash compensation expenses, non-recurring transaction expenses, extraordinary gains and losses, gains and losses on discontinued operations, losses on debt extinguishment and includes cash distributions received from affiliates, plus pro-rata earnings from material acquisitions. The facility also includes a minimum current ratio covenant of no less than 1.00 to 1.00, measured quarterly. The minimum current ratio is calculated as the ratio of current assets, plus revolver availability, to current liabilities excluding borrowings under the revolver. This calculation also excludes all of CNXC's current assets, current liabilities and revolver availability. The current ratio was 2.29 to 1.00 at December 31, 2015. Affirmative and negative covenants in the facility limit the Company's ability to dispose of assets, make investments, purchase or redeem CONSOL Energy common stock, pay dividends, merge with another corporation and amend, modify or restate the senior unsecured notes. The credit facility allows unlimited investments in joint ventures for the development and operation of natural gas gathering systems. The facility permits CONSOL Energy to separate its natural gas and coal businesses if the leverage ratio (which, is essentially, the ratio of debt to EBITDA) of the natural gas business immediately after the separation would not be greater than 2.75 to 1.00. At December 31, 2015, the facility had $952 million of borrowings outstanding and $258 million of letters of credit outstanding, leaving $790 million of unused capacity. From time to time, CONSOL Energy is required to post financial assurances to satisfy contractual and other requirements generated in the normal course of business. Some of these assurances are posted to comply with federal, state or other government agencies' statutes and regulations. CONSOL Energy sometimes uses letters of credit to satisfy these requirements and these letters of credit reduce the Company's borrowing facility capacity.

In May 2015, the facility was amended to allow, among other things, spinoffs, or other public equity offering transactions in regard to subsidiaries that own metallurgical coal assets and thermal coal assets, and all arrangements, actions and transactions in connection therewith, including releases of associated entities or assets from the Credit Agreement and any liens granted under the loan documents. The Amendment also permits the incurrence of a term loan facility up to the aggregate principal amount of $600,000 at subsidiaries of the Company that own the thermal coal assets and the incurrence of a revolving credit facility up to an aggregate principal amount of $300,000 at subsidiaries of the Company that own the metallurgical coal assets.

CONSOL Energy terminated its accounts receivable securitization facility effective July 7, 2015. The outstanding borrowings at June 30, 2015 were repaid, and the outstanding letters of credit at June 30, 2015 were transferred against the revolving credit facility.

CONSOL Energy has completed the refinancing of approximately $5.0 billion of short and long-term borrowings since the second quarter of 2014.

Uncertainty in the financial markets brings additional potential risks to CONSOL Energy. The risks include declines in the Company's stock price, less availability and higher costs of additional credit, potential counterparty defaults, and commercial bank failures. Financial market disruptions may impact the Company's collection of trade receivables. As a result, CONSOL Energy regularly monitors the creditworthiness of its customers. CONSOL Energy believes that its current group of customers are financially sound and represent no abnormal business risk.

CONSOL Energy believes that cash generated from operations, asset sales and the Company's borrowing capacity will be sufficient to meet the Company's working capital requirements, anticipated capital expenditures (other than major acquisitions), scheduled debt payments and anticipated dividend payments and to provide required letters of credit. Nevertheless, the ability of CONSOL Energy to satisfy its working capital requirements, to service its debt obligations, to fund planned capital expenditures, or to pay dividends will depend upon future operating performance, which will be affected by prevailing economic conditions in the natural gas and coal industries and other financial and business factors, some of which are beyond CONSOL Energy's control.

In order to manage the market risk exposure of volatile natural gas prices in the future, CONSOL Energy enters into various physical natural gas supply transactions with both natural gas marketers and end users for terms varying in length. CONSOL Energy has also entered into various gas swap and option transactions, which exist parallel to the underlying physical transactions. The fair value of these contracts was a net asset of $267 million at December 31, 2015. No issues related to the Company's hedge agreements have been encountered to date.

CONSOL Energy frequently evaluates potential acquisitions. CONSOL Energy has funded acquisitions with cash generated from operations and a variety of other sources, depending on the size of the transaction, including debt and equity financing. There can be no assurance that additional capital resources, including debt and equity financing, will be available to CONSOL Energy on terms which CONSOL Energy finds acceptable, or at all.

Cash Flows (in millions)

	For the Years Ended December 31,		
	2015	2014	Change
Cash flows from operating activities	$506	$937	$(431)
Cash used in investing activities	$(996)	$(1,041)	$45
Cash provided by (used in) financing activities	$386	$(46)	$432

Cash flows provided by operating activities changed $431 million in the period-to-period comparison primarily due to the following items:

- Net income decreased $528 million in the period-to-period comparison;
- Adjustments to reconcile net income to cash flow provided by operating activities increased $829 million due to the impairment of exploration and production properties (see Note 11 - Property, Plant and Equipment, in the Notes to Audited Financial Statements in Item 8 of this Form 10-K for more information), offset, in part, by a decrease of $142 million related to changes in deferred taxes, a decrease of $197 million due to the unrealized gain on commodity derivative instruments, a decrease of $216 million in other post-employment benefits plan amendments, and additional depreciation, depletion, and amortization of $44 million.
- Other changes in operating assets, operating liabilities, other assets and other liabilities which occurred throughout both periods also contributed to the decrease in operating cash flows.

Net cash used in investing activities changed $45 million in the period-to-period comparison primarily due to the following items:

• Capital expenditures decreased $471 million due to:

- Gas segment capital expenditures decreased $271 million due to a decrease in drilling and completion costs in the Marcellus and Utica plays as the Company temporarily suspended these operations in August 2015 due to depressed commodity prices. In the fourth quarter of 2015, the Company resumed completions operations on its inventory of drilled but uncompleted wells.
- Coal segment capital expenditures decreased $200 million primarily due to the completion of the Harvey Mine in the prior period, as well as, decreased maintenance of production capital at the PA operations complex.

- Proceeds from the sale of assets decreased $247 million. Sales in 2015 include $76 million received in September 2015 related to the sale of CONSOL Energy's interest in its Western Allegheny Energy joint venture as well as various other smaller transactions which occurred in 2015. Significant sales in 2014 include $75 million received in March 2014 related to the Harvey Mine shield sale-leaseback as well as $46 million received in January 2014 as reimbursement from Noble Energy for 50% of the Dominion Resources lease acquisition and $14 million received in

June 2014 related to the McElroy shields buyout. Additionally, the fourth quarter of 2014 included $97 million in proceeds from the sale of coal mines and reserves in Illinois and a $52 million sale of the Company's interest in Shaft Drillers International, as well as various other transactions that occurred throughout 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 more information. The remaining increase was due to various items that occurred throughout both periods, none of which were individually material.

- Cash provided by equity affiliates decreased $179 million primarily due to a $204 million decrease in return of investments due to the IPO of CONE Midstream Partners, LP occurring in September 2014 along with an $18 million reduction in

net equity due to the sale of the Company's interest in the Western Allegheny Energy joint venture in September 2015 and $8 million less of distributions received from various equity partners in the year ended December 31, 2015 compared to the year ended December 31, 2014.

Net cash used in financing activities changed $432 million in the period-to-period comparison primarily due to the following items:

- During the year ended December 31, 2015, CONSOL Energy received $952 million of proceeds from the senior secured credit facility compared to payments on short-term borrowings of $12 million during the year ended December 31, 2014.
- In the year ended December 31, 2015, CONSOL Energy had net payments of $771 million related to the partial extinguishment of the 2020 and 2021 bonds offset, in part, by the issuance of the 2023 bonds. In the year ended December 31, 2014, CONSOL Energy had net proceeds from long-term borrowings of $41 million. See Note 14 - Long-Term Debt in the Notes to the Audited Consolidated Financial Statements of this Form 10-K for additional details.
- In the year ended December 31, 2015, CONSOL Energy received $185 million of net proceeds under the CNX Coal Resources LP credit facility.
- In the year ended December 31, 2015, CONSOL Energy received proceeds of $148 million from the IPO of CNX Coal Resources LP.
- In the year ended December 31, 2015, CONSOL Energy repurchased $72 million of its common stock on the open market under the previously announced share repurchase program. No repurchases were made in the year ended December 31, 2014.
- In 2015, CONSOL Energy paid four quarterly dividends totaling $33 million at an amount per share of $0.145. In 2014, CONSOL Energy paid four quarterly dividends totaling $58 million at an amount per share of $0.250.
- The remaining changes are due to various transactions that occurred throughout both periods.

The following is a summary of our significant contractual obligations at December 31, 2015 (in thousands):

	Payments due by Year				
	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years	Total
Purchase Order Firm Commitments	$62,837	$64,474	$31,445	$11,964	$170,720
Gas Firm Transportation and Processing	130,848	243,732	214,389	652,869	1,241,838
Long-Term Debt	3,225	4,420	261,089	2,475,998	2,744,732
Interest on Long-Term Debt	168,195	336,740	331,074	304,407	1,140,416
Capital (Finance) Lease Obligations	7,847	15,101	14,299	5,894	43,141
Interest on Capital (Finance) Lease Obligations	2,745	3,865	1,974	196	8,780
Operating Lease Obligations	95,454	151,653	45,874	70,891	363,872
Long-Term Liabilities—Employee Related (a)	67,935	132,322	130,443	566,512	897,212
Other Long-Term Liabilities (b)	300,375	188,880	99,608	343,096	931,959
Total Contractual Obligations (c)	$839,461	$1,141,187	$1,130,195	$4,431,827	$7,542,670

(a) Long-term liabilities—employee related include other post-employment benefits, work-related injuries and illnesses. Estimated salaried retirement contributions required to meet minimum funding standards under ERISA are excluded from the pay-out table due to the uncertainty regarding amounts to be contributed. CONSOL Energy does not expect to contribute to the pension in 2016.

(b)

Other long-term liabilities include mine reclamation and closure and other long-term liability costs.

(c) The significant obligation table does not include obligations to taxing authorities due to the uncertainty surrounding the ultimate settlement of amounts and timing of these obligations.

Debt

At December 31, 2015, CONSOL Energy had total long-term debt and capital lease obligations of $2,788 million outstanding, including the current portion of long-term debt of $7 million. This long-term debt consisted of:

- An aggregate principal amount of $74 million of 8.25% senior unsecured notes due in April 2020. Interest on the notes is payable April 1 and October 1 of each year. Payment of the principal and interest on the notes is guaranteed by most of CONSOL Energy’s subsidiaries.
- An aggregate principal amount of $21 million of 6.375% senior unsecured notes due in March 2021. Interest on the notes is payable March 1 and September 1 of each year. Payment of the principal and interest on the notes is guaranteed by most of CONSOL Energy's subsidiaries.
- An aggregate principal amount of $1,850 million of 5.875% senior unsecured notes due in April 2022 plus $6 million of unamortized bond premium. Interest on the notes is payable April 15 and October 15 of each year. Payment of the principal and interest on the notes is guaranteed by most of CONSOL Energy's subsidiaries.
- An aggregate principal amount of $500 million of 8.00% senior unsecured notes due in April 2023 less $7 million of unamortized bond discount. Interest on the notes is payable April 1 and October 1 of each year. Payment of the principal and interest on the notes is guaranteed by most of CONSOL Energy's subsidiaries.
- An aggregate principal amount of $103 million of industrial revenue bonds which were issued to finance the Baltimore port facility and bear interest at 5.75% per annum and mature in September 2025. Interest on the industrial revenue bonds is payable March 1 and September 1 of each year. Payment of the principal and interest on the notes is guaranteed by CONSOL Energy.
- Advance royalty commitments of $10 million with an average interest rate of 16.35% per annum.
- An aggregate principal amount of $3 million on a note maturing through March 2018.
- An aggregate principal amount of $43 million of capital leases with a weighted average interest rate of 5.93% per annum.
- An aggregate principal amount of $185 million in outstanding borrowings under the revolver for CNXC. CONSOL Energy is not a guarantor of CNXC's revolving credit facility.

At December 31, 2015, CONSOL Energy had an aggregate principal amount of $952 million and approximately $258 million of letters of credit outstanding under the $2 billion senior secured revolving credit facility.

Total Equity and Dividends

CONSOL Energy had total equity of $4,856 million at December 31, 2015 compared to $5,329 million at December 31, 2014. See the Consolidated Statements of Stockholders' Equity in Item 8 of this Form 10-K for additional details.

Dividend information for the current year to date is as follows:

Declaration Date	Amount Per Share	Record Date	Payment Date
February 1, 2016	$0.0100	February 16, 2016	March 3, 2016
October 28, 2015	$0.0100	November 12, 2015	November 20, 2015
July 29, 2015	$0.0100	August 10, 2015	August 24, 2015
April 29, 2015	$0.0625	May 11, 2015	May 21, 2015

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.

Off-Balance Sheet Transactions

CONSOL Energy does not maintain off-balance sheet transactions, arrangements, obligations or other relationships with unconsolidated entities or others that are reasonably likely to have a material current or future effect on CONSOL Energy's financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources which are not disclosed in the Notes to the Audited Consolidated Financial Statements. CONSOL Energy participates in the UMWA Combined Benefit Fund and the UMWA 1992 Benefit Plan which generally accepted accounting principles recognize on a pay as you go basis. These benefit arrangements may result in additional liabilities that are not recognized on the balance sheet at December 31, 2015. The various multi-employer benefit plans are discussed in Note 18—Other Employee Benefit Plans in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K. CONSOL Energy also uses a combination of surety bonds, corporate guarantees and letters of credit to secure our financial obligations for employee-related, environmental, performance and various other items which are not reflected on the balance sheet at December 31, 2015. Management believes these items will expire without being funded. See Note 24—Commitments and Contingencies in the Notes to the Audited Consolidated Financial Statements included in Item 8 of this Form 10-K for additional details of the various financial guarantees that have been issued by CONSOL Energy.

Recent Accounting Pronouncements

In January 2016, the FASB issued Update 2016-01 - Financial Instruments-Overall (Subtopic 825-10): Recognition and Measurement of Financial Asset and Financial Liabilities. The main objective in developing this Update is enhancing the reporting model for financial instruments to provide users of financial statements with more decision-useful information. The amendments in this Update address certain aspects of recognition, measurement, presentation and disclosure of financial instruments. This Update requires the following: equity investments (except those accounted for under the equity method of accounting or those that result in consolidation of the investee) to be measured at fair value with changes in fair value recognized in net income, a qualitative assessment to identify impairment of equity investments without readily determinable fair values, the use of the exit price notion when measuring the fair value of financial instruments for disclosure purposes, an entity to present separately in other comprehensive income the portion of the total change in the fair value of a liability resulting from a change in the instrument-specific credit risk when the entity has elected to measure the liability at fair value in accordance with the fair value option for financial instruments, and separate presentation of financial assets and financial liabilities by measurement category and form of financial asset on the balance sheet or the accompanying notes to the financial statements. The Update also eliminates the requirement for public business entities to disclose the method(s) and significant assumptions used to estimate the fair value that is required to be disclosed for financial instruments measured at amortized cost on the balance sheet and clarifies that an entity should evaluate the need for a valuation allowance on a deferred tax asset related to available-for-sale securities in combination with the entity's other deferred tax assets. For public business entities, the amendments in this Update are effective for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years. Early application to financial statements of fiscal years or interim periods that have not yet been issued is permitted as of the beginning of the fiscal year of adoption. The Company is currently evaluating the impact this guidance may have on CONSOL Energy's financial statements.

In August 2015, the FASB issued Update 2015-14 - Revenue from Contracts with Customers (Topic 606): Deferral of Effective Date. In response to stakeholders' requests to defer the effective date of the guidance in Update 2014-09 - Revenue from Contracts with Customers (Topic 606), and in consideration of feedback received through extensive outreach with preparers, practitioners, and users of financial statements, the Board issued proposed Accounting Standards Update, Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date. Respondents to the proposed Update overwhelmingly support a deferral and noted that providing sufficient time for implementation of the guidance in Update 2014-09 is critical to its success. As such, the Board is issuing this Update in consideration of respondents' feedback, including the timing of when Update 2014-09 was issued, the current status of key standard-setting activities associated with the guidance in Update 2014-09, and the availability of information technology solutions to facilitate the implementation of the guidance in Update 2014-09. The amendments in this

Update defer the effective date of Update 2014-09 for all entities by one year. Public business entities, certain not-for-profit entities, and certain employee benefit plans should apply the guidance in Update 2014-09 to annual reporting periods beginning after December 15, 2017, including interim reporting periods within that reporting period. Earlier application is permitted only as of annual reporting periods beginning after December 15, 2016, including interim reporting periods within that reporting period. The Company is currently evaluating the impact this guidance may have on CONSOL Energy's financial statements.

In July 2015, the FASB issued Update 2015-11 - Inventory (Topic 330): Simplifying the Measurement of Inventory. The Board is issuing this Update as part of its Simplification Initiative. The amendments in this Update do not apply to inventory that is measured using last-in, first-out (LIFO) or the retail inventory method. The amendments apply to all other inventory, which includes inventory that is measured using first-in, first-out (FIFO) or average cost. Topic 330, Inventory, currently requires an entity to measure inventory at the lower of cost or market, where market could be replacement cost, net realizable value, or net realizable value less an approximately normal profit margin. In accordance with this Update, an entity should now measure

inventory within the scope of this Update at the lower of cost and net realizable value. Net realizable value is the estimated selling prices in the ordinary course of business, less reasonably predictable costs of completion, disposal, and transportation. Subsequent measurement is unchanged for inventory measured using LIFO or the retail inventory method. Other than the change in the subsequent measurement guidance from the lower of cost or market to the lower of cost and net realizable value for inventory within the scope of this Update, there are no other substantive changes to the guidance on measurement of inventory. For public business entities, the amendments in this Update are effective for fiscal years beginning after December 15, 2016, including interim periods within those fiscal years. The amendments in this Update should be applied prospectively with earlier application permitted as of the beginning of an interim or annual reporting period. The Company is currently evaluating the impact this guidance may have on CONSOL Energy's financial statements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

In addition to the risks inherent in operations, CONSOL Energy is exposed to financial, market, political and economic risks. The following discussion provides additional detail regarding CONSOL Energy's exposure to the risks of changing commodity prices, interest rates and foreign exchange rates.

CONSOL Energy is exposed to market price risk in the normal course of selling natural gas and to a lesser extent in the sale of coal. CONSOL Energy uses fixed-price contracts, options and derivative commodity instruments to minimize exposure to market price volatility in the sale of natural gas. CONSOL Energy sells coal under both short-term and long-term contracts with fixed price and/or indexed price contracts that reflect market value. Under our risk management policy it is not our intent to engage in derivative activities for speculative purposes.

CONSOL Energy has established risk management policies and procedures to strengthen the internal control environment of the marketing of commodities produced from its asset base. All of the derivative instruments without other risk assessment procedures are held for purposes other than trading. They are used primarily to mitigate uncertainty, volatility and cover underlying exposures. CONSOL Energy's market risk strategy incorporates fundamental risk management tools to assess market price risk and establish a framework in which management can maintain a portfolio of transactions within pre-defined risk parameters.

CONSOL Energy believes that the use of derivative instruments, along with our risk assessment procedures and internal controls, mitigates our exposure to material risks. However, the use of derivative instruments without other risk assessment procedures could materially affect CONSOL Energy's results of operations depending on market prices. Nevertheless, we believe that use of these instruments will not have a material adverse effect on our financial position or liquidity.

For a summary of accounting policies related to derivative instruments, see Note 1—Significant Accounting Policies in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K.

At December 31, 2015, our open derivative instruments were in a net asset position with a fair value of $267 million. A sensitivity analysis has been performed to determine the incremental effect on future earnings related to open derivative instruments at December 31, 2015. A hypothetical 10 percent increase in future natural gas prices would decrease future earnings related to derivatives by $129 million.

CONSOL Energy's interest expense is sensitive to changes in the general level of interest rates in the United States. At December 31, 2015, CONSOL Energy had $2,570 billion aggregate principal amount of debt outstanding under fixed-rate instruments and $1,137 million of debt outstanding under variable-rate instruments. CONSOL Energy's primary exposure to market risk for changes in interest rates relates to our revolving credit facility, under which there were $952 million of borrowings at December 31, 2015 and CNXC revolving credit facility under which there were $185 million of borrowings at December 31, 2015. A hypothetical 100 basis-point increase in the average rate for CONSOL Energy's and CNXC's revolving credit facility would decrease pre-tax future earnings related to interest expense by $9 million.

Almost all of CONSOL Energy’s transactions are denominated in U.S. dollars, and, as a result, it does not have material exposure to currency exchange-rate risks.

Hedging Volumes

As of January 13, 2016, our hedged volumes for the periods indicated are as follows:

	For the Three Months Ended				
	March 31,	June 30,	September 30,	December 31,	Total Year
2016 Fixed Price Volumes					
Hedged Bcf	55.6	55.6	56.2	56.2	223.6
Weighted Average Hedge Price per Mcf	$3.44	$3.13	$3.13	$3.31	$3.26
2017 Fixed Price Volumes					
Hedged Bcf	38.6	39.1	39.5	39.5	156.7
Weighted Average Hedge Price per Mcf	$2.99	$3.11	$3.11	$3.11	$3.08
2018 Fixed Price Volumes					
Hedged Bcf	18.7	18.9	19.1	19.1	75.8
Weighted Average Hedge Price per Mcf	$3.07	$3.07	$3.07	$3.07	$3.07

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders of CONSOL Energy Inc. and Subsidiaries

We have audited the accompanying consolidated balance sheets of CONSOL Energy Inc. and Subsidiaries as of December 31, 2015 and 2014, and the related consolidated statements of income, comprehensive income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2015. Our audits also included the financial statement schedule listed in the index at Item 15(a). These financial statements and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of CONSOL Energy Inc. and Subsidiaries at December 31, 2015 and 2014, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2015, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), CONSOL Energy Inc. and Subsidiaries' internal control over financial reporting as of December 31, 2015, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission 2013 framework and our report dated February 5, 2016 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Pittsburgh, Pennsylvania
February 5, 2016

CONSOL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME

(Dollars in thousands, except per share data)	For the Years Ended December 31,		
	2015	2014	2013
Revenues and Other Income:			
Natural Gas, NGLs and Oil Sales	$726,921	$1,004,924	$662,446
Gain on Commodity Derivative Instruments	392,942	23,193	75,255
Coal Sales	1,657,865	2,052,166	2,018,067
Other Outside Sales	30,967	276,242	259,783
Production Royalty Interests and Purchased Gas Sales	59,631	91,427	69,733
Freight-Outside Coal	25,597	28,148	35,438
Miscellaneous Other Income (Note 4)	145,968	207,103	111,483
Gain on Sale of Assets	74,510	43,601	67,480
Total Revenue and Other Income	3,114,401	3,726,804	3,299,685
Costs and Expenses:			
Exploration and Production Costs			
Lease Operating Expense	98,997	109,172	87,543
Transportation, Gathering and Compression (Note 27)	355,923	258,110	201,024
Production, Ad Valorem, and Other Fees	30,438	39,418	28,676
Direct Administrative and Selling	46,192	55,004	49,092
Depreciation, Depletion and Amortization	370,374	323,600	240,867
Exploration and Production Related Other Costs	10,119	23,355	61,104
Production Royalty Interests and Purchased Gas Costs	46,544	77,185	57,865
Other Corporate Expenses	90,583	86,588	95,535
Impairment of Exploration and Production Properties	828,905	—	—
General and Administrative	54,244	64,047	39,047
Total Exploration and Production Costs	1,932,319	1,036,479	860,753
Coal Costs			
Operating and Other Costs	863,199	1,322,737	1,315,584
Royalties and Production Taxes	78,844	100,890	102,128
Direct Administrative and Selling	33,476	44,106	49,223
Depreciation, Depletion and Amortization	279,209	280,150	256,647
Freight Expense	25,597	28,148	35,438
General and Administrative Costs	29,836	45,160	40,047
Other Corporate Expenses	39,687	55,321	55,802
Total Coal Costs	1,349,848	1,876,512	1,854,869
Other Costs			
Miscellaneous Operating Expense	64,096	309,174	315,180
General and Administrative Costs	—	788	936
Depreciation, Depletion and Amortization	18	1,896	2,674
Loss on Debt Extinguishment	67,751	95,267	—
Interest Expense (Note 5)	199,269	223,564	219,198
Total Other Costs	331,134	630,689	537,988
Total Costs and Expenses	3,613,301	3,543,680	3,253,610
(Loss) Earnings Before Income Tax	(498,900)	183,124	46,075
Income Tax (Benefit) Expense (Note 7)	(134,425)	14,347	(33,189)
(Loss) Income from Continuing Operations	(364,475)	168,777	79,264
(Loss) Income from Discontinued Operations, net	—	(5,687)	579,792
Net (Loss) Income	(364,475)	163,090	659,056

Less: Net Income (Loss) Attributable to Noncontrolling Interests	10,410	—	(1,386)
Net (Loss) Income Attributable to CONSOL Energy Shareholders	$(374,885)	$163,090	$660,442

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

CONSOL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
(CONTINUED)

(Dollars in thousands, except per share data)	For the Years Ended December 31, 2015	2014	2013
(Loss) Earnings Per Share			
Basic			
(Loss) Income from Continuing Operations	$(1.64)	$0.73	$0.35
(Loss) Income from Discontinued Operations	—	(0.02)	2.54
Total Basic (Loss) Earnings Per Share	$(1.64)	$0.71	$2.89
Dilutive			
(Loss) Income from Continuing Operations	$(1.64)	$0.73	$0.35
(Loss) Income from Discontinued Operations	—	(0.03)	2.52
Total Dilutive (Loss) Earnings Per Share	$(1.64)	$0.70	$2.87
Dividends Paid Per Share	$0.145	$0.25	$0.375

CONSOL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Dollars in thousands)

	For the Years Ended December 31, 2015	2014	2013
Net (Loss) Income	$(364,475)	$163,090	$659,056
Other Comprehensive (Loss) Income:			
Actuarially Determined Long-Term Liability Adjustments (Net of tax: $53,253, ($56,304), ($276,928))	(86,447)	94,989	456,493
Net Increase in the Value of Cash Flow Hedge (Net of tax: $-, ($55,767), ($29,407))	—	97,316	45,631
Reclassification of Cash Flow Hedges from Other Comprehensive Income to Earnings (Net of tax: $45,054, $10,465, $53,990)	(78,051)	(18,288)	(79,899)
Other Comprehensive (Loss) Income	(164,498)	174,017	422,225
Comprehensive (Loss) Income	(528,973)	337,107	1,081,281
Less: Net Income (Loss) Attributable to Noncontrolling Interests	10,410	—	(1,386)
Comprehensive (Loss) Income Attributable to CONSOL Energy Inc. Shareholders	$(539,383)	$337,107	$1,082,667

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

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CONSOL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Dollars in thousands)

	December 31, 2015	December 31, 2014
ASSETS		
Current Assets:		
Cash and Cash Equivalents	$72,578	$176,989
Accounts and Notes Receivable:		
Trade	200,508	260,943
Other Receivables	122,095	346,020
Inventories (Note 9)	97,438	101,873
Recoverable Income Taxes	13,887	20,401
Prepaid Expenses	298,257	187,742
Total Current Assets	804,763	1,093,968
Property, Plant and Equipment (Note 11):		
Property, Plant and Equipment	15,574,946	14,674,777
Less—Accumulated Depreciation, Depletion and Amortization	5,905,569	4,512,305
Total Property, Plant and Equipment—Net	9,669,377	10,162,472
Other Assets:		
Investment in Affiliates	237,330	152,958
Other	218,432	245,248
Total Other Assets	455,762	398,206
TOTAL ASSETS	$10,929,902	$11,654,646

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

CONSOL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Dollars in thousands, except per share data)

	December 31, 2015	December 31, 2014
LIABILITIES AND EQUITY		
Current Liabilities:		
Accounts Payable	$271,394	$531,973
Current Portion of Long-Term Debt (Note 14 and Note 15)	6,650	7,202
Short-Term Notes Payable (Note 12)	952,000	—
Other Accrued Liabilities (Note 13)	450,893	602,972
Total Current Liabilities	1,680,937	1,142,147
Long-Term Debt:		
Long-Term Debt (Note 14)	2,712,911	3,203,920
Capital Lease Obligations (Note 15)	35,294	39,456
Total Long-Term Debt	2,748,205	3,243,376
Deferred Credits and Other Liabilities:		
Deferred Income Taxes (Note 7)	74,629	259,024
Postretirement Benefits Other Than Pensions (Note 16)	630,892	703,680
Pneumoconiosis Benefits (Note 17)	113,032	116,941
Mine Closing (Note 8)	299,280	306,789
Gas Well Closing (Note 8)	164,634	175,369
Workers' Compensation (Note 17)	69,812	75,947
Salary Retirement (Note 16)	91,596	109,956
Reclamation (Note 8)	34,150	33,788
Other	166,959	158,171
Total Deferred Credits and Other Liabilities	1,644,984	1,939,665
TOTAL LIABILITIES	6,074,126	6,325,188
Stockholders' Equity:		
Common Stock, $0.01 Par Value; 500,000,000 Shares Authorized, 229,054,236 Issued and Outstanding at December 31, 2015; 230,265,463 Issued and Outstanding at December 31, 2014	2,294	2,306
Capital in Excess of Par Value	2,435,497	2,424,102
Preferred Stock, 15,000,000 Shares Authorized, None Issued and Outstanding	—	—
Retained Earnings	2,579,834	3,054,150
Accumulated Other Comprehensive Loss	(315,598)	(151,100)
Common Stock in Treasury, at Cost—No Shares at December 31, 2015 and 2014	—	—
Total CONSOL Energy Inc. Stockholders' Equity	4,702,027	5,329,458
Noncontrolling Interest	153,749	—
TOTAL EQUITY	4,855,776	5,329,458
TOTAL LIABILITIES AND EQUITY	$10,929,902	$11,654,646

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

CONSOL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(Dollars in thousands, except per share data)

	Common Stock	Capital in Excess of Par Value	Retained Earnings (Deficit)	Accumulated Other Comprehensive Income (Loss)	Common Stock in Treasury	Total CONSOL Energy Inc. Stockholders' Equity	Non-Controlling Interest	Total Equity
December 31, 2012	$2,284	$2,296,908	$2,402,551	$ (747,342)	$(609)	$3,953,792	$(47)	$3,953,745
Net Income (Loss)	—	—	660,442	—	—	660,442	(1,386)	659,056
Gas Cash Flow Hedge (Net of $24,583 Tax)	—	—	—	(34,268)	—	(34,268)	—	(34,268)
Actuarially Determined Long-Term Liability Adjustments (Net of ($276,928) Tax)	—	—	—	456,493	—	456,493	—	456,493
Comprehensive Income (Loss)	—	—	660,442	422,225	—	1,082,667	(1,386)	1,081,281
Issuance of Treasury Stock	—	—	(12,641)	—	609	(12,032)	—	(12,032)
Issuance of Common Stock	10	3,717	—	—	—	3,727	—	3,727
Tax Cost from Stock-Based Compensation	—	(2,075)	—	—	—	(2,075)	—	(2,075)
Amortization of Stock-Based Compensation Awards	—	66,042	—	—	—	66,042	—	66,042
Net Change in Noncontrolling Interest	—	—	—	—	—	—	1,433	1,433
Dividends ($0.375 per share)	—	—	(85,832)	—	—	(85,832)	—	(85,832)
December 31, 2013	2,294	2,364,592	2,964,520	(325,117)	—	5,006,289	—	5,006,289
Net Income	—	—	163,090	—	—	163,090	—	163,090
Gas Cash Flow Hedge (Net of ($45,302) Tax)	—	—	—	79,028	—	79,028	—	79,028
Actuarially Determined Long-Term Liability Adjustments (Net of ($56,304) Tax)	—	—	—	94,989	—	94,989	—	94,989

Comprehensive Income	—	—	163,090	174,017	—	337,107	—	337,107
Issuance of Treasury Stock	—	—	(15,954)	—	—	(15,954)	—	(15,954)
Issuance of Common Stock	12	15,004	—	—	—	15,016	—	15,016
Tax Benefit from Stock-Based Compensation	—	2,629	—	—	—	2,629	—	2,629
Amortization of Stock-Based Compensation Awards	—	41,877	—	—	—	41,877	—	41,877
Dividends ($0.25 per share)	—	—	(57,506)	—	—	(57,506)	—	(57,506)
December 31, 2014	2,306	2,424,102	3,054,150	(151,100)	—	5,329,458	—	5,329,458
Net (Loss) Income	—	—	(374,885)	—	—	(374,885)	10,410	(364,475)
Gas Cash Flow Hedge (Net of $45,054 Tax)	—	—	—	(78,051)	—	(78,051)	—	(78,051)
Actuarially Determined Long-Term Liability Adjustments (Net of $53,253 Tax)	—	—	—	(86,447)	—	(86,447)	—	(86,447)
Comprehensive (Loss) Income	—	—	(374,885)	(164,498)	—	(539,383)	10,410	(528,973)
Treasury Stock Activity	—	—	(12,181)	—	—	(12,181)	—	(12,181)
Issuance of Common Stock	10	8,278	—	—	—	8,288	—	8,288
Retirement of Common Stock (2,213,100 shares)	(22)	(17,683)	(53,969)	—	—	(71,674)	—	(71,674)
Tax Cost from Stock-Based Compensation	—	(3,706)	—	—	—	(3,706)	—	(3,706)
Amortization of Stock-Based Compensation Awards	—	24,506	—	—	—	24,506	—	24,506
Distributions to Noncontrolling Interest	—	—	—	—	—	—	(5,060)	(5,060)
Proceeds from Sale of MLP Interest	—	—	—	—	—	—	148,399	148,399
Dividends ($0.145 per share)	—	—	(33,281)	—	—	(33,281)	—	(33,281)
December 31, 2015	$2,294	$2,435,497	$2,579,834	$ (315,598)	$—	$4,702,027	$153,749	$4,855,776

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

CONSOL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

(Dollars in thousands)	For the Years Ended December 31,		
	2015	2014	2013
Operating Activities:			
Net (Loss) Income	$(364,475)	$163,090	$659,056
Adjustments to Reconcile Net Income to Net Cash Provided By Continuing Operating Activities:			
Net Loss (Income) from Discontinued Operations	—	5,687	(579,792)
Depreciation, Depletion and Amortization	649,601	605,646	500,188
Impairment of Exploration and Production Properties	828,905	—	—
Non-Cash Other Post-Employment Benefits	(261,750)	(45,749)	—
Stock-Based Compensation	24,506	41,877	56,987
Gain on Sale of Assets	(74,510)	(43,601)	(67,480)
Loss on Debt Extinguishment	67,751	95,267	—
Gain on Commodity Derivative Instruments	(392,942)	(23,193)	(75,255)
Net Cash Received in Settlement of Commodity Derivative Instruments	196,348	19,025	79,900
Deferred Income Taxes	(152,051)	(10,430)	(29,014)
Return on Equity Investment	35,466	102,174	—
Equity in Earnings of Affiliates	(54,897)	(49,791)	(33,133)
Changes in Operating Assets:			
Accounts and Notes Receivable	118,205	(97,248)	135,970
Inventories	4,435	19,933	12,894
Prepaid Expenses	127,687	4,536	(7,864)
Changes in Other Assets	3,792	(20,767)	23,800
Changes in Operating Liabilities:			
Accounts Payable	(148,580)	27,465	(99,944)
Accrued Interest	26,649	(9,868)	(87)
Other Operating Liabilities	(152,288)	195,431	(78,443)
Changes in Other Liabilities	(8,677)	(54,274)	—
Other	32,674	45,496	55,787
Net Cash Provided by Continuing Operations	505,849	970,706	553,570
Net Cash (Used In) Provided by Discontinued Operating Activities	—	(33,926)	105,206
Net Cash Provided by Operating Activities	505,849	936,780	658,776
Cash Flows from Investing Activities:			
Capital Expenditures	(1,022,567)	(1,493,425)	(1,496,056)
Changes in Restricted Cash	—	—	68,673
Proceeds from Sales of Assets	110,571	356,836	483,969
Net Investments in Equity Affiliates	(84,221)	95,207	(35,712)
Net Cash Used in Continuing Operations	(996,217)	(1,041,382)	(979,126)
Net Cash Provided by Discontinued Investing Activities	—	—	777,145
Net Cash Used in Investing Activities	(996,217)	(1,041,382)	(201,981)
Cash Flows from Financing Activities:			
Proceeds from (Payments on) Short-Term Borrowings	952,000	(11,736)	—
Payments on Miscellaneous Borrowings	(4,338)	(10,286)	(31,544)
Payments on Securitization Facility	—	—	(37,846)
Payments on Long-Term Notes, including Redemption Premium	(1,263,719)	(1,819,005)	—
Net Proceeds from Revolver - MLP	185,000	—	—
Distributions to Noncontrolling Interest	(5,060)	—	—

Proceeds from Sale of MLP Interest	148,359	—	—
Proceeds from Issuance of Long-Term Notes	492,760	1,859,920	—
Tax Benefit from Stock-Based Compensation	208	2,629	2,929
Dividends Paid	(33,281)	(57,506)	(85,832)
Proceeds from Issuance of Common Stock	8,288	15,016	3,727
Issuance of Treasury Stock	—	—	(2,151)
Purchases of Treasury Stock	(71,674)	—	—
Debt Issuance and Financing Fees	(22,586)	(24,861)	—
Net Cash Provided by (Used in) Continuing Operations	385,957	(45,829)	(150,717)
Net Cash Used in Discontinued Financing Activities	—	—	(520)
Net Cash Provided by (Used in) Financing Activities	385,957	(45,829)	(151,237)
Net (Decrease) Increase in Cash and Cash Equivalents	(104,411)	(150,431)	305,558
Cash and Cash Equivalents at Beginning of Period	176,989	327,420	21,862
Cash and Cash Equivalents at End of Period	$72,578	$176,989	$327,420

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

CONSOL ENERGY INC. AND SUBSIDIARIES
NOTES TO AUDITED CONSOLIDATED FINANCIAL STATEMENTS
(Dollars in thousands, except per share data)

NOTE 1—SIGNIFICANT ACCOUNTING POLICIES:

A summary of the significant accounting policies of CONSOL Energy Inc. and subsidiaries (CONSOL Energy or the Company) is presented below. These, together with the other notes that follow, are an integral part of the Consolidated Financial Statements.

Basis of Consolidation:

The Consolidated Financial Statements include the accounts of majority-owned and controlled subsidiaries. Investments in business entities in which CONSOL Energy does not have control, but has the ability to exercise significant influence over the operating and financial policies, are accounted for under the equity method. Investments in oil and gas producing entities are accounted for under the proportionate consolidation method. The accounts of variable interest entities, where CONSOL Energy is the primary beneficiary, are included in the Consolidated Financial Statements. All significant intercompany transactions and accounts have been eliminated in consolidation.

Discontinued Operations:

Businesses to be divested are classified in the Consolidated Financial Statements as either discontinued operations or held for sale when the provision of Accounting Standards Codification (ASC) Topic 205 or ASC Topic 360 are met. For businesses classified as discontinued operations, the balance sheet amounts and results of operations are reclassified from their historical presentation to assets and liabilities of discontinued operations on the Consolidated Balance Sheets and to discontinued operations on the Consolidated Statements of Income and Cash Flows, respectively, for all periods presented. The gains or losses associated with these divested businesses are recorded in discontinued operations on the Consolidated Statements of Income. Additionally, the accompanying notes, including segment information, do not include the assets, liabilities, or operating results of businesses classified as discontinued operations for all periods presented. Management expects these businesses will be disposed of within one year, without any significant continuing involvement following their divestiture.

Use of Estimates:

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and various disclosures. Actual results could differ from those estimates. The most significant estimates included in the preparation of the financial statements are related to other postretirement benefits, coal workers' pneumoconiosis, workers' compensation, salary retirement benefits, stock-based compensation, asset retirement obligations, deferred income tax assets and liabilities, contingencies, and the values of coal and gas reserves.

Cash and Cash Equivalents:

Cash and cash equivalents include cash on hand and on deposit at banking institutions as well as all highly liquid short-term securities with original maturities of three months or less.

Trade Accounts Receivable:

Trade accounts receivable are recorded at the invoiced amount and do not bear interest. CONSOL Energy reserves for specific accounts receivable when it is probable that all or a part of an outstanding balance will not be collected, such as customer bankruptcies. Collectability is determined based on terms of sale, credit status of customers and various other circumstances. CONSOL Energy regularly reviews collectability and establishes or adjusts the allowance as necessary using the specific identification method. Account balances are charged off against the allowance after all means of collection have been exhausted and the potential for recovery is considered remote. Reserves for uncollectible amounts were not material in the periods presented. In addition, there were no material financing receivables with a contractual maturity greater than one year at December 31, 2015 or 2014.

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Inventories:
Inventories are stated at the lower of cost or market. The cost of coal inventories is determined by the first-in, first-out (FIFO) method. Coal inventory costs include labor, supplies, equipment costs, operating overhead, depreciation, depletion, amortization, and other related costs. The cost of supplies inventory is determined by the average cost method and includes operating and maintenance supplies to be used in our coal and gas operations.
Property, Plant and Equipment:
CONSOL Energy uses the successful efforts method of accounting for gas producing activities. Costs of property acquisitions, successful exploratory, development wells and related support equipment and facilities are capitalized. Periodic valuation provisions for impairment of capitalized costs of unproved mineral interests are expensed. Costs of unsuccessful exploratory wells are expensed when such wells are determined to be non-productive, or if the determination cannot be made after finding sufficient quantities of reserves to continue evaluating the viability of the project. The costs of producing properties and mineral interests are amortized using the units-of-production method. Wells and related equipment and intangible drilling costs are also amortized on a units-of-production method. Units-of-production amortization rates are revised at least once per year, or more frequently if events and circumstances indicate an adjustment is necessary. Such revisions are accounted for prospectively as changes in accounting estimates.

Property, plant and equipment is recorded at cost upon acquisition. Expenditures which extend the useful lives of existing plant and equipment are capitalized. Interest costs applicable to major asset additions are capitalized during the construction period. Costs of additional mine facilities required to maintain production after a mine reaches the production stage, generally referred to as “receding face costs,” are expensed as incurred; however, the costs of additional airshafts and new portals are capitalized. Planned major maintenance costs which do not extend the useful lives of existing plant and equipment are expensed as incurred.

Coal exploration costs are expensed as incurred. Coal exploration costs include those incurred to ascertain existence, location, extent or quality of ore or minerals before beginning the development stage of the mine.

Costs of developing new underground mines and certain underground expansion projects are capitalized. Underground development costs, which are costs incurred to make the mineral physically accessible, include costs to prepare property for shafts, driving main entries for ventilation, haulage, personnel, construction of airshafts, roof protection and other facilities. Costs of developing the first pit within a permitted area of a surface mine are capitalized. A surface mine is defined as the permitted mining area which includes various adjacent pits that share common infrastructure, processing equipment and a common ore body. Surface mine development costs include construction costs for entry roads, drilling, blasting and removal of overburden in developing the first cut for mountain stripping or box cuts for surface stripping. Stripping costs incurred during the production phase of a mine are expensed as incurred.

Airshafts and capitalized mine development associated with a coal reserve are amortized on a units-of-production basis as the coal is produced so that each ton of coal is assigned a portion of the unamortized costs. The Company employs this method to match costs with the related revenues realized in a particular period. Rates are updated when revisions to coal reserve estimates are made. Coal reserve estimates are reviewed when information becomes available that indicates a reserve change is needed, or at a minimum once per year. Any material effect from changes in estimates is disclosed in the period the change occurs. Amortization of development cost begins when the development phase is complete and the production phase begins. At an underground mine, the end of the development phase and the beginning of the production phase takes place when construction of the mine for economic extraction is substantially complete. Coal extracted during the development phase is incidental to the mine's production capacity and is not considered to shift the mine into the production phase.

Coal reserves are controlled either through fee ownership or by lease. The duration of the leases vary; however, the lease terms generally are extended automatically through the exhaustion of economically recoverable reserves, as long as active mining continues. Coal interests held by lease provide the same rights as fee ownership for mineral extraction and are legally considered real property interests. The Company also makes advance payments (advanced mining royalties) to lessors under certain lease agreements that are recoupable against future production, and it makes payments that are generally based upon a specified rate per ton or a percentage of gross realization from the sale of the coal. The Company evaluates its properties periodically for impairment issues or whenever events or circumstances indicate that the carrying amount may not be recoverable.

Advance mining royalties are advance payments made to lessors under terms of mineral lease agreements that are recoupable against future production using the units-of-production method. Depletion of leased coal interests is computed using the units-of-production method over proven and probable coal reserves. Advance mining royalties and leased coal interests are evaluated

periodically, or at a minimum once per year, for impairment issues or whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. Any revisions are accounted for prospectively as changes in accounting estimates.

When properties are retired or otherwise disposed, the related cost and accumulated depreciation are removed from the respective accounts and any profit or loss on disposition is recognized as a gain or loss in other income.

Depreciation of plant and equipment is calculated on the straight-line method over their estimated useful lives or lease terms, generally as follows:

	Years
Buildings and improvements	10 to 45
Machinery and equipment	3 to 25
Leasehold improvements	Life of Lease

Costs to obtain coal lands are capitalized based on the cost at acquisition and are amortized using the units-of-production method over all estimated proven and probable coal reserve tons assigned and accessible to the mine. Proven and probable coal reserves exclude non-recoverable coal reserves and anticipated processing losses. Rates are updated when revisions to coal reserve estimates are made. Coal reserve estimates are reviewed when events and circumstances indicate a reserve change is needed, or at a minimum once a year. Amortization of coal interests begins when the coal reserve is produced. At an underground coal mine, a ton is considered produced once it reaches the surface area of the mine. Any material effect from changes in estimates is disclosed in the period the change occurs.

Costs for purchased and internally developed software are expensed until it has been determined that the software will result in probable future economic benefits and management has committed to funding the project. Thereafter, all direct costs of materials and services incurred in developing or obtaining software, including certain payroll and benefit costs of employees associated with the project, are capitalized and amortized using the straight-line method over the estimated useful life which does not exceed seven years.

Impairment of Long-lived Assets:

Impairment of long-lived assets is recorded when indicators of impairment are present and the undiscounted cash flows estimated to be generated by those assets are less than the assets' carrying value. The carrying value of the assets is then reduced to its estimated fair value which is usually measured based on an estimate of future discounted cash flows. Impairment of equity investments is recorded when indicators of impairment are present and the estimated fair value of the investment is less than the assets' carrying value.

Impairment of Proved Properties

CONSOL Energy performs a quantitative annual impairment test during the fourth quarter of each year over proved properties using the published NYMEX forward prices, timing, methods and other assumptions consistent with historical periods. During interim periods, management updates these annual tests whenever events or changes in circumstances indicate that a property’s carrying amount may not be recoverable. Throughout the first six months of 2015, spot prices and forward curves for natural gas continued to decline from December 31, 2014 prices, which, together with other macro-economic factors in the exploration and production industry, were deemed indicators of impairment for all of the Company's natural gas assets. Impairment tests require that the Company first compare future undiscounted cash flows by asset group to their respective carrying values. If the carrying amount exceeds the estimated undiscounted future cash flows, a reduction of the carrying amount of the natural gas properties to their estimated fair values is required, which is determined based on discounted cash flow techniques using a

market-specific weighted average cost of capital.

During the quarter ended June 30, 2015, certain of the Company's producing gas properties, primarily shallow oil and gas assets, failed the undiscounted cash flow portion of the test. After performing the discounted cash flow portion of the test, CONSOL Energy recorded an impairment of $824,742, included in Impairment of Exploration and Production Properties within the Consolidated Statements of Income. Valuation of the impaired assets is a Level 3 measurement as it incorporates significant unobservable inputs, such as future production levels and operating costs, within the discounted cash flow analysis. The impairment related to approximately 95% of the Company's shallow oil and gas assets in West Virginia and Pennsylvania.

There were no other additional impairments related to proved properties in the year ended December 31, 2015. There were no such impairments for the years ended December 31, 2014 or 2013.

Impairment of Unproved Properties

CONSOL Energy evaluates capitalized costs of unproved gas properties for recoverability on a prospective basis. Indicators of potential impairment include potential shifts in business strategy, overall economic factors and historical experience. If it is determined that the properties will not yield proved reserves, the related costs are expensed in the period the determination is made. For the quarter ended June 30, 2015, unproved property impairments relating to the determination that the properties will not yield proved reserves were $4,163 and are included in Impairment of Exploration and Production Properties within the Consolidated Statements of Income. This impairment primarily relates to the court ruling in June 2015 in the state of New York that officially bans hydraulic fracturing.

There were no other additional impairments related to unproved properties in the year ended December 31, 2015. There were no such impairments for the years ended December 31, 2014 and 2013.

Capitalized costs of unproved gas properties are evaluated for recoverability on a prospective basis. Indicators of potential impairment include potential shifts in business strategy, overall economic factors and historical experience. If it is determined that the properties will not yield proved reserves, the related costs are expensed in the period the determination is made. Exploration expense was $10,119, $23,355 and $61,104 for the years ended December 31, 2015, 2014 and 2013, respectively, which was primarily related to lease expirations.

Income Taxes:

Deferred tax assets and liabilities are recognized for the expected future tax consequences of events that have been recognized in CONSOL Energy's financial statements or tax returns. The provision for income taxes represents income taxes paid or payable for the current year and the change in deferred taxes, excluding the effects of acquisitions during the year. Deferred taxes result from differences between the financial and tax bases of CONSOL Energy's assets and liabilities and are adjusted for changes in tax rates and tax laws when changes are enacted. Valuation allowances are recorded to reduce deferred tax assets when it is more likely than not that a deferred tax benefit will not be realized.

CONSOL Energy evaluates all tax positions taken on the state and federal tax filings to determine if the position is more likely than not to be sustained upon examination. For positions that do not meet the more likely than not to be sustained criteria, the Company determines, on a cumulative probability basis, the largest amount of benefit that is more likely than not to be realized upon ultimate settlement. A previously recognized tax position is derecognized when it is subsequently determined that a tax position no longer meets the more likely than not threshold to be sustained. The evaluation of the sustainability of a tax position and the probable amount that is more likely than not is based on judgment, historical experience and on various other assumptions that the Company believes are reasonable under the circumstances. The results of these estimates, that are not readily apparent from other sources, form the basis for recognizing an uncertain tax position liability. Actual results could differ from those estimates upon subsequent resolution of identified matters.

Postretirement Benefits Other Than Pensions:

Postretirement benefit obligations established by the Coal Industry Retiree Health Benefit Act of 1992 (the Health Benefit Act) are treated as a multi-employer plan which requires expense to be recorded for the associated obligations as payments are made. Postretirement benefits other than pensions, except for those established pursuant to the Health Benefit Act, are accounted for in accordance with the Retirement Benefits Compensation and Non-retirement Postemployment Benefits Compensation Topics of the Financial Accounting Standards Board (FASB) Accounting Standards Codification, which requires employers to accrue the cost of such retirement benefits for the employees' active service periods. Such liabilities are determined on an actuarial basis and CONSOL Energy is primarily self-insured for these benefits. Differences between actual and expected results or changes in the value of obligations are recognized through Other Comprehensive Income.

Pneumoconiosis Benefits and Workers' Compensation:

CONSOL Energy is required by federal and state statutes to provide benefits to certain current and former totally disabled employees or their dependents for awards related to coal workers' pneumoconiosis. CONSOL Energy is also

required by various state statutes to provide workers' compensation benefits for employees who sustain employment-related physical injuries or some types of occupational disease. Workers' compensation benefits include compensation for their disability, medical costs, and on some occasions, the cost of rehabilitation. CONSOL Energy is primarily self-insured for these benefits. Provisions for estimated benefits are determined on an actuarial basis.

Mine Closing, Reclamation and Gas Well Closing Costs:

CONSOL Energy accrues for mine closing costs, reclamation costs, perpetual water care costs and dismantling and removing costs of gas-related facilities using the accounting treatment prescribed by the Asset Retirement and Environmental Obligations Topic of the FASB Accounting Standards Codification. This topic requires the fair value of an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. The present value of the estimated asset retirement costs is capitalized as part of the carrying amount of the long-lived asset. Depreciation of the capitalized asset retirement cost is generally determined on a units-of-production basis. Accretion of the asset retirement obligation is recognized over time and generally will escalate over the life of the producing asset, typically as production declines. Accretion is included in Deprecation, Depletion and Amortization on the Consolidated Statements of Income. Asset retirement obligations primarily relate to the closure of coal mines and natural gas wells, which includes treatment of water and the reclamation of land upon exhaustion of gas and coal reserves.

Accrued mine closing costs, perpetual care costs, reclamation and costs of dismantling and removing natural gas-related facilities are regularly reviewed by management and are revised for changes in future estimated costs and regulatory requirements.

Retirement Plans:

CONSOL Energy has non-contributory defined benefit retirement plans. Effective December 31, 2015, CONSOL's qualified defined benefit retirement plans have been frozen. The benefits for these plans are based primarily on years of service and employees' pay. These plans are accounted for using the guidance outlined in the Compensation - Retirement Benefits Topic of the FASB Accounting Standards Codification. The cost of these retiree benefits are recognized over the employees' service periods. CONSOL Energy uses actuarial methods and assumptions in the valuation of defined benefit obligations and the determination of expense. Differences between actual and expected results or changes in the value of obligations and plan assets are recognized through Other Comprehensive Income.

Revenue Recognition:

Revenues are recognized when title passes to the customers. For natural gas sales, this occurs at the contractual point of delivery. For domestic coal sales, this generally occurs when coal is loaded at mine or offsite storage locations. For export coal sales, this generally occurs when coal is loaded onto marine vessels at terminal locations. For equipment sales, this generally occurs when the products are delivered. For terminal, land, and research and development, revenue is recognized generally as the service is provided to the customer.

CONSOL Energy has operational natural gas-balancing agreements with various interstate pipelines. These imbalance agreements are managed internally using the sales method of accounting. The sales method recognizes revenue when the gas is taken by the purchaser.

CONSOL Energy sells natural gas to accommodate the delivery points of its customers. In general, this gas is purchased at market price and re-sold on the same day at market price less a small transaction fee. These matching buy/sell transactions include a legal right of offset of obligations and have been simultaneously entered into with the counterparty. These transactions qualify for netting under the Nonmonetary Transactions Topic of the FASB Accounting Standards Codification and are, therefore, recorded net within the Consolidated Statements of Income in the Production Royalty Interests and Purchased Gas Sales line.

CONSOL Energy purchases natural gas produced by third parties at market prices less a fee. The gas purchased from third party producers is then resold to end users or gas marketers at current market prices. These revenues and expenses are recorded gross as Production Royalty Interests and Purchased Gas Sales in the Consolidated Statements of Income. Purchased gas revenue is recognized when title passes to the customer. Purchased gas costs are recognized when title passes to CONSOL Energy from the third party producer.

Royalty Interest Gas Sales represent the revenues related to the portion of production sold by CONSOL Energy that belongs to royalty interest owners.

Freight Revenue and Expense:

Shipping and handling costs invoiced to coal customers and paid to third-party carriers are recorded as Freight-Outside Coal revenue and Freight Expense, respectively.

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Royalty Recognition:

Royalty expenses for gas rights are included in Production Royalty Interests and Purchased Gas Costs when the related revenue for the gas sale is recognized. Royalty expenses for coal rights are included in Cost of Goods Sold and Other Operating Charges when the related revenue for the coal sale is recognized. These royalty expenses are paid in cash in accordance with the terms of each agreement. Revenues for gas and coal sold related to production under royalty contracts, versus owned by CONSOL Energy, are recorded on a gross basis.

Contingencies:

From time to time, CONSOL Energy, or our subsidiaries, is subject to various lawsuits and claims with respect to such matters as personal injury, wrongful death, damage to property, exposure to hazardous substances, governmental regulations including environmental remediation, employment and contract disputes, and other claims and actions, arising out of the normal course of business. Liabilities are recorded when it is probable that obligations have been incurred and the amounts can be reasonably estimated. Estimates are developed through consultation with legal counsel involved in the defense of these matters and are based upon the nature of the lawsuit, progress of the case in court, view of legal counsel, prior experience in similar matters and management's intended response. Environmental liabilities are not discounted or reduced by possible recoveries from third-parties. Legal fees associated with defending these various lawsuits and claims are expensed when incurred.

Stock-Based Compensation:

Stock-based compensation expense for all stock-based compensation awards is based on the grant date fair value estimated in accordance with the provisions of the Stock Compensation Topic of the FASB Accounting Standards Codification. CONSOL Energy recognizes these compensation costs on a straight-line basis over the requisite service period of the award, which is generally the award's vesting term. See Note 19–Stock-Based Compensation for more information.

Earnings per Share:

Basic earnings per share are computed by dividing net (loss) income attributable to CONSOL Energy Shareholders by the weighted average shares outstanding during the reporting period. Diluted earnings per share is computed similarly to basic earnings per share, except that the weighted average shares outstanding are increased to include the number of additional shares of common stock that would have been outstanding if the potentially dilutive shares had been issued. Potentially dilutive securities include outstanding stock and performance options, restricted stock units, performance share units, and CONSOL stock units. The dilutive effect of potentially dilutive securities is reflected in diluted earnings per share by use of the treasury stock method. CONSOL Energy includes the impact of pro forma deferred tax assets in determining potential windfalls and shortfalls for purposes of calculating assumed proceeds under the treasury stock method. The table below sets forth the share-based awards that have been excluded from the computation of the diluted earnings per share because their effect would be anti-dilutive:

	For the Years Ended December 31,		
	2015	2014	2013
Anti-Dilutive Options	3,621,002	358,731	1,976,549
Anti-Dilutive Restricted Stock Units	1,375,659	—	282,230
Anti-Dilutive Performance Share Units	113,531	—	—
Anti-Dilutive Performance Share Options	802,804	—	802,804
	5,912,996	358,731	3,061,583

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The computations for basic and dilutive earnings per share are as follows:

	For the Years Ended December 31,		
	2015	2014	2013
(Loss) Income from Continuing Operations	$(364,475)	$168,777	$79,264
(Loss) Income from Discontinued Operations	—	(5,687)	579,792
Less: Net Income (Loss) Attributable to Noncontrolling Interest	10,410	—	(1,386)
Net (Loss) Income Attributable to CONSOL Energy Inc. Shareholders	$(374,885)	$163,090	$660,442
Weighted Average Shares of Common Stock Outstanding:			
Basic	229,186,125	229,994,407	228,728,628
Effect of Stock-based Compensation Awards	—	1,585,871	1,349,314
Dilutive	229,186,125	231,580,278	230,077,942
Earnings Per Share:			
Basic (Continuing Operations)	$(1.64)	$0.73	$0.35
Basic (Discontinued Operations)	—	(0.02)	2.54
Total Basic	$(1.64)	$0.71	$2.89
Dilutive (Continuing Operations)	$(1.64)	$0.73	$0.35
Dilutive (Discontinued Operations)	—	(0.03)	2.52
Total Dilutive	$(1.64)	$0.70	$2.87

Shares of common stock outstanding were as follows:

	2015	2014	2013
Balance, Beginning of Year	230,265,463	229,145,736	228,094,712
Issuance Related to Stock-Based Compensation(1)	1,001,873	1,119,727	1,051,024
Retirement of Common Stock(2)	(2,213,100)	—	—
Balance, End of Year	229,054,236	230,265,463	229,145,736

(1) See Note 19–Stock-Based Compensation for additional information.
(2) See Note 6–Stock Repurchase for additional information.

Other Comprehensive (Loss) Income:

Changes in Accumulated Other Comprehensive (Loss) / Income by component, net of tax, were as follows:

	Gains and Losses on Cash Flow Hedges	Postretirement Benefits	Total
Balance at December 31, 2014	$121,521	$(272,621)	$(151,100)
Other comprehensive income before reclassifications	—	37,579	37,579
Amounts reclassified from accumulated other comprehensive income	(78,051)	(124,026)	(202,077)
Other comprehensive loss	(78,051)	(86,447)	(164,498)
Balance at December 31, 2015	$43,470	$(359,068)	$(315,598)

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The following table shows the reclassification of adjustments out of Accumulated Other Comprehensive Loss:

	For the Years Ended December 31,		
	2015	2014	2013
Derivative Instruments (Note 23)			
Natural Gas Price Swaps	$(123,105)	$(28,753)	$(133,889)
Tax Benefit	45,054	10,465	53,990
Net of Tax	$(78,051)	$(18,288)	$(79,899)
Actuarially Determined Long-Term Liability Adjustments*(Note 16 and Note 17)			
Amortization of Prior Service Costs	$(336,993)	$(22,381)	$(32,164)
Recognized Net Actuarial Loss	119,222	46,155	86,481
Curtailment Loss (Gain)	5	(36,182)	—
Settlement Loss	19,053	29,095	39,482
Total	(198,713)	16,687	93,799
Tax Benefit (Expense)	74,687	(6,139)	(35,806)
Net of Tax	$(124,026)	$10,548	$57,993

*Excludes amounts related to the remeasurement of the Actuarially Determined Long-Term Liabilities for the years ended December 31, 2015, December 31, 2014 and December 31, 2013. Excludes $258,250, net of tax, of reclassifications of adjustments out of accumulated other comprehensive income related to discontinued operations for the year ended December 31, 2013.

Accounting for Derivative Instruments:

CONSOL Energy enters into financial derivative instruments to manage its exposure to commodity price volatility. The derivatives are accounted for as an asset or a liability in the accompanying Consolidated Balance Sheets at their fair value using “Level Two” inputs, which is further defined in Note 22 - Fair Value of Financial Instruments. Changes in the fair values of derivatives are recorded in earnings unless special hedge accounting criteria are met. For derivatives designated as cash flow hedges, the effective portions of changes in the fair values of the derivatives are reported in Other Comprehensive Income or Loss (OCI) on the Consolidated Balance Sheets, net of tax, and reclassified into Natural Gas, NGLs and Oil Sales on the Consolidated Statements of Income in the same period or periods in which the forecasted transactions affect earnings. Any ineffective portion of a hedge is recognized in earnings in the current period.

CONSOL Energy formally assesses, both at inception of the hedge and on an ongoing basis, whether each derivative is highly effective for the purpose of offsetting changes in the fair values or the cash flows of the hedged item. If it is determined that a derivative is not highly effective as a hedge or if a derivative ceases to be a highly effective hedge, CONSOL Energy will discontinue hedge accounting prospectively.

On December 31, 2014, CONSOL Energy de-designated all of its derivative positions as hedging instruments. Subsequent changes in fair value will be recorded in current earnings. Deferred gains and losses in OCI as of that date will be recorded in earnings when the related physical transaction occurs or when it is determined that the physical transaction is no longer probable to occur.

All of CONSOL Energy’s derivative instruments are subject to master netting arrangements with its counterparties, none of which currently require CONSOL Energy to post collateral for any of its hedges. However, as stated in the counterparty master agreements, if CONSOL Energy's obligations with one of its counterparties cease to be secured on the same basis as similar obligations with the other lenders under the credit facility, CONSOL Energy would be required to post collateral for hedges that are in a liability position in excess of defined thresholds. Each of CONSOL Energy's counterparty master agreements allows, in the event of default, the ability to elect early termination of outstanding contracts. If early termination is elected, CONSOL Energy and the applicable counterparty would net settle all open hedge positions.

CONSOL Energy is exposed to credit risk in the event of nonperformance by counterparties, whose creditworthiness is subject to continuing review. Historically, CONSOL Energy has not experienced any issues of non-performance by derivative counterparties.

Recent Accounting Pronouncements:

In January 2016, the FASB issued Update 2016-01 - Financial Instruments-Overall (Subtopic 825-10): Recognition and Measurement of Financial Asset and Financial Liabilities. The main objective in developing this Update is enhancing the reporting model for financial instruments to provide users of financial statements with more decision-useful information. The amendments in this Update address certain aspects of recognition, measurement, presentation and disclosure of financial instruments. This Update requires the following: equity investments (except those accounted for under the equity method of accounting or those that result in consolidation of the investee) to be measured at fair value with changes in fair value recognized in net income, a qualitative assessment to identify impairment of equity investments without readily determinable fair values, the use of the exit price notion when measuring the fair value of financial instruments for disclosure purposes, an entity to present separately in other comprehensive income the portion of the total change in the fair value of a liability resulting from a change in the instrument-specific credit risk when the entity has elected to measure the liability at fair value in accordance with the fair value option for financial instruments, and separate presentation of financial assets and financial liabilities by measurement category and form of financial assets on the balance sheet or the accompanying notes to the financial statements. The Update also eliminates the requirement for public business entities to disclose the method(s) and significant assumptions used to estimate the fair value that is required to be disclosed for financial instruments measured at amortized cost on the balance sheet and clarifies that an entity should evaluate the need for a valuation allowance on a deferred tax asset related to available-for-sale securities in combination with the entity's other deferred tax assets. For public business entities, the amendments in this Update are effective for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years. Early application to financial statements of fiscal years or interim periods that have not yet been issued is permitted as of the beginning of the fiscal year of adoption. The Company is currently evaluating the impact this guidance may have on CONSOL Energy's financial statements.
In August 2015, the FASB issued Update 2015-14 - Revenue from Contracts with Customers (Topic 606): Deferral of Effective Date. In response to stakeholders’ requests to defer the effective date of the guidance in Update 2014-09 - Revenue from Contracts with Customers (Topic 606), and in consideration of feedback received through extensive outreach with preparers, practitioners, and users of financial statements, the Board issued proposed Accounting Standards Update, Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date. Respondents to the proposed Update overwhelmingly support a deferral and noted that providing sufficient time for implementation of the guidance in Update 2014-09 is critical to its success. As such, the Board is issuing this Update in consideration of respondents’ feedback, including the timing of when Update 2014-09 was issued, the current status of key standard-setting activities associated with the guidance in Update 2014-09, and the availability of information technology solutions to facilitate the implementation of the guidance in Update 2014-09. The amendments in this Update defer the effective date of Update 2014-09 for all entities by one year. Public business entities, certain not-for-profit entities, and certain employee benefit plans should apply the guidance in Update 2014-09 to annual reporting periods beginning after December 15, 2017, including interim reporting periods within that reporting period. Earlier application is permitted only as of annual reporting periods beginning after December 15, 2016, including interim reporting periods within that reporting period. The Company is currently evaluating the impact this guidance may have on CONSOL Energy's financial statements.

In July 2015, the FASB issued Update 2015-11 - Inventory (Topic 330): Simplifying the Measurement of Inventory. The Board is issuing this Update as part of its Simplification Initiative. The amendments in this Update do not apply to inventory that is measured using last-in, first-out (LIFO) or the retail inventory method. The amendments apply to all other inventory, which includes inventory that is measured using first-in, first-out (FIFO) or average cost. Topic 330, Inventory, currently requires an entity to measure inventory at the lower of cost or market, where market could be replacement cost, net realizable value, or net realizable value less an approximately normal profit margin. In accordance with this Update, an entity should now measure inventory within the scope of this Update at the lower of cost and net realizable value. Net realizable value is the estimated selling prices in the ordinary course of business,

less reasonably predictable costs of completion, disposal, and transportation. Subsequent measurement is unchanged for inventory measured using LIFO or the retail inventory method. Other than the change in the subsequent measurement guidance from the lower of cost or market to the lower of cost and net realizable value for inventory within the scope of this Update, there are no other substantive changes to the guidance on measurement of inventory. For public business entities, the amendments in this Update are effective for fiscal years beginning after December 15, 2016, including interim periods within those fiscal years. The amendments in this Update should be applied prospectively with earlier application permitted as of the beginning of an interim or annual reporting period. The Company is currently evaluating the impact this guidance may have on CONSOL Energy's financial statements.

Reclassifications:

Certain amounts in prior periods have been reclassified to conform with the report classifications of the year ended December 31, 2015, respectively, with no effect on previously reported net income or stockholders' equity.

Subsequent Events:

The Company has evaluated all subsequent events through the date the financial statements were issued. No material recognized or non-recognizable subsequent events were identified.

NOTE 2—DISCONTINUED OPERATIONS:
In December 2013, CONSOL Energy completed the sale of its Consolidation Coal Company (CCC) subsidiary, which included all five of its longwall coal mines in West Virginia, to a subsidiary of Murray Energy Corporation (Murray Energy). CONSOL Energy retained overriding royalty interests in certain reserves sold in the transaction. Murray Energy also assumed $2,050,656 of CONSOL Energy's employee benefit obligations valued as of December 5, 2013 and its UMWA 1974 Pension Trust obligations. Murray Energy is primarily liable for all 1993 Coal Act liabilities. Cash proceeds of $825,285 were received related to this transaction, which were net of $24,715 in transaction fees. A pre-tax gain of $1,035,346 was included in Income from Discontinued Operations in the Consolidated Statements of Income. In the first quarter of 2014, there was a pre-tax reduction in gain on sale of $7,044 related to the estimated working capital adjustment and various other miscellaneous items.

For all periods presented in the accompanying Consolidated Statements of Income, the sale of CCC is classified as discontinued operations. There were no other active businesses classified as discontinued operations in the three-year period ended December 31, 2015.

In late 2013, CONSOL Energy reclassified CCC to discontinued operations based on the decision to divest the business. The Consolidated Financial Statements for all periods presented were reclassified to reflect the business in discontinued operations. The divestiture of CCC was completed on December 5, 2013.

The following table details selected financial information for the divested business included within discontinued operations:

	For the Years Ended December 31,		
	2015	2014	2013
Sales	$—	$—	$2,598,875
(Loss) Income from discontinued operations before income taxes	$—	$(7,044)	$969,685
Income taxes benefit (expense)	—	1,357	(389,893)
(Loss) Income from discontinued operations	$—	$(5,687)	$579,792

There were no remaining major classes of assets or liabilities of discontinued operations at December 31, 2015 and 2014.

NOTE 3—ACQUISITIONS AND DISPOSITIONS:
In September 2015, CONSOL Energy sold its 49% interest in Western Allegheny Energy (WAE), a joint venture with Rosebud Mining Company engaged in coal mining activities in Pennsylvania. CONSOL Energy received $76,297 in cash and a $2,136 reduction in certain liabilities. During the third quarter of 2015, CONSOL Energy also received a cash distribution of $10,780 from WAE. The net gain on the sale was $48,468 and was included in the Gain on Sale of Assets in the Consolidated Statements of Income.

In December 2014, CNX Gas Company finalized an agreement with Columbia Energy Ventures (CEVCO) to sublease from CEVCO approximately 20,000 acres of Utica Shale and Upper Devonian gas rights in Greene and Washington Counties in Pennsylvania and Marshall and Ohio Counties in West Virginia. Up-front bonus consideration of up to $96,106 will be paid by CONSOL Energy over a five year period as drilling occurs in addition to royalties, of which $49,533 was recorded in Other Current Liabilities and $40,286 was recorded on a discounted basis in Other Long-Term Liabilities. In the year ended December 31, 2015, CONSOL Energy made payments to

CEVCO totaling $50,969. As of December 31, 2015, the amount recorded in Other Current Liabilities was $8,349 and Other Long-term Liabilities was $29,333.

In December 2014, CONSOL Energy completed the sale of its industrial supplies subsidiary, to an unrelated third party for expected net proceeds of approximately $51,000, of which $44,035 was received and included in cash flows from investing activities during the year ended December 31, 2014. In connection with the sale, CONSOL Energy signed a supply agreement under which, among other things, it will continue to purchase certain goods exclusively from the new entity for a period of at least three years. CONSOL Energy recorded a net loss on the sale of $30,845, which was included in Gain on Sale of Assets in the Consolidated Statement of Income. In December 2015, there was $6,258 of expense related to the settlement of working capital adjustments and other matters in conjunction with the sale.

In March 2014, CONSOL Energy completed a sale-leaseback of longwall shields for the Harvey Mine (formerly the BMX Mine). Cash proceeds for the sale offset the basis of $75,357; therefore, no gain or loss was recognized on the sale. The five- year lease has been accounted for as an operating lease.

In December 2013, CONSOL Energy acquired the gas drilling rights to approximately 90,000 contiguous acres from Dominion Transmission, a unit of Dominion Resources. The acreage, which is associated with Dominion's Fink-Kennedy, Lost Creek, and Racket Newberne gas storage fields in West Virginia, lies in the northern portion of Lewis County and the southern portion of Harrison County. CONSOL anticipates that over one-half of the acres will have wet gas. CONSOL Energy has acquired the gas rights to both the Marcellus Shale and the Upper Devonian formations in the storage fields. Consideration of up to $190,000 will be paid by CONSOL Energy in two installments: 50% was paid at closing and the balance is due over time as the acres are drilled. In addition, CONSOL Energy will pay an overriding royalty to Dominion Resources based on a sliding scale. Finally, CONSOL Energy has committed to be an anchor shipper on Dominion's transmission system, with the specific terms to be negotiated at a future date. CONSOL Energy paid $91,243 in 2013 related to this transaction. In the year ended December 31, 2014, CONSOL Energy made an additional bonus payment of $16,000 to Dominion Transmission. Following the acquisition by CONSOL Energy, Noble Energy Inc., our joint venture partner, acquired 50% of the acres and reimbursed CONSOL Energy for 50% of the associated costs.

In August 2013, CONSOL Energy completed the sale of its 50% interest in the CONSOL Energy/Devon Energy joint venture in Alberta, Canada. The properties and coal leases included were those related to Grassy Mountain, Bellevue, Adanac, and Lynx Creek (Crowsnest Pass). Cash proceeds for the sale were $24,764. A gain of $15,260 was included in Gain on Sale of Assets in the Consolidated Statement of Income.

In June 2013, CONSOL Energy completed the sale of Potomac coal reserves in Grant and Tucker Counties in West Virginia. Cash proceeds for the sale were $25,000. A gain of $24,663 was included in Gain on Sale of Assets in the Consolidated Statement of Income.

In April 2013, the Company and the Commonwealth of Pennsylvania (Commonwealth) entered into a Settlement Agreement and Release settling all of the Commonwealth's claims regarding the Ryerson Park Dam (Dam) and the Ryerson Park Lake (Lake). The Settlement provided, in part, for the payment to the Commonwealth of $36,000 for use to rebuild the Dam and restore the Lake with $13,728 of the settlement amount credited to lease bonus and royalty payments on the Commonwealth's Marcellus gas interests within the Park, subject to the Company's agreement to extract the gas from surface facilities located outside of the boundaries of the Park. The Settlement also provided, in part, for the conveyance by the Company to the Commonwealth of eight surface parcels containing approximately 506 acres of land adjoining the Park after the parcels are no longer needed for the Company's operations and the conveyance by the Commonwealth to the Company of certain coal and mining rights in an area of the Bailey Mine where a mining permit application has been approved but with special conditions that will need further approval.

In March 2013, CNX Gas Company completed negotiations with theAllegheny County Airport Authority, which operates the Pittsburgh International Airport and the Allegheny County Airport, for the lease of the oil and gas rights on approximately 9.3 thousand acres. A majority of these contiguous acres are in the liquids area of the Marcellus Shale play. CNX Gas Company paid $46,315 as an up-front bonus payment at closing. At December 31, 2014, approximately 7.6% of the bonus payment continues to be held in escrow while negotiations continue for a portion of the acres associated with the Allegheny County Airport and other acres that have potentially defective title. CNX Gas Company must spud a well by February 21, 2015 and proceed with due diligence to complete the well or the lease terminates and CNX Gas Company forgoes the bonus. Our joint venture partner, Noble Energy Inc., has acquired a 50% interest in the acreage and accordingly, reimbursed CNX Gas Company for 50% of the associated costs during the year ended December 31, 2013.

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NOTE 4—MISCELLANEOUS OTHER INCOME:

	For the Years Ended December 31,		
	2015	2014	2013
Equity in earnings of affiliates	$54,897	$49,791	$33,133
Rental income	37,996	45,061	3,518
Royalty income	15,422	19,653	16,906
Right of way issuance	13,289	7,333	4,536
Gathering revenue	12,692	29,558	7,019
Interest income	2,299	2,303	15,889
Coal contract settlement	—	30,000	—
PA Turnpike settlement	—	—	9,000
Business interruption insurance	—	—	5,445
Other	9,373	23,404	16,037
Miscellaneous Other Income	$145,968	$207,103	$111,483

NOTE 5—INTEREST EXPENSE:

	For the Years Ended December 31,		
	2015	2014	2013
Interest on debt	$201,300	$239,984	$260,233
Interest on other payables, net	478	(2,847)	2,682
Interest capitalized	(2,509)	(13,573)	(43,717)
Total Interest Expense	$199,269	$223,564	$219,198

Interest on other payables for the years ended December 31, 2015 and December 31, 2013 includes interest expense of $53 and $1,369, respectively, related to uncertain tax positions. Interest on other payables for the year ended December 31, 2014 includes a reversal of interest expense of $6,200 related to uncertain tax positions. See Note 7–Income Taxes for more information.

NOTE 6— STOCK REPURCHASE:

In December 2014, CONSOL Energy's Board of Directors approved a stock repurchase program under which CONSOL Energy may purchase from time to time up to $250,000 of its common stock over the next two years. Under the terms of the program, CONSOL Energy may make repurchases in the open market, in privately negotiated transactions, accelerated repurchase programs or in structured share repurchase programs. Any repurchases of common stock will be funded from available cash on hand or short-term borrowings. The program does not obligate CONSOL Energy to acquire any particular amount of common stock, and it may be modified or suspended at any time at the Company's discretion. The program will be conducted in compliance with applicable legal requirements and within the limits imposed by any credit agreement, receivables purchase agreement or indenture and is subject to market conditions and other factors. During the year ended December 31, 2015, 2,213,100 shares were repurchased under this program and retired at an average price of $32.37 per share. No shares were repurchased under this program for the year ended December 31, 2014.

NOTE 7—INCOME TAXES:

Income tax (benefit) expense provided on earnings from continuing operations consisted of:

	For The Years Ended December 31,		
	2015	2014	2013
Current:			
U.S. Federal	$21,526	$15,625	$6,729
U.S. State	(4,911)	7,741	(10,904)
Non-U.S.	1,011	1,411	—
	17,626	24,777	(4,175)
Deferred:			
U.S. Federal	(192,139)	(10,697)	(32,125)
U.S. State	40,088	267	(4,651)
Non-U.S.	—	—	7,762
	(152,051)	(10,430)	(29,014)
Total Income Tax (Benefit) Expense	$(134,425)	$14,347	$(33,189)

The components of the net deferred taxes are as follows:

	December 31,	
	2015	2014
Deferred Tax Assets:		
Postretirement benefits other than pensions	$257,604	$283,188
Net operating loss - Federal	165,951	—
Alternative minimum tax	143,122	152,149
Gas well closing	79,246	77,610
Net operating loss - State	76,171	49,638
Mine closing	63,399	63,640
Equity Partnerships	45,746	28,316
Pneumoconiosis benefits	44,830	45,926
Mine subsidence	44,317	38,456
Foreign tax credit	39,850	—
Workers' compensation	31,544	32,949
Salary retirement	30,177	43,505
Reclamation	14,122	14,380
Capital lease	4,404	19,267
Other	65,427	81,690
Total Deferred Tax Assets	1,105,910	930,714
Valuation Allowance	(78,306)	(6,096)
Net Deferred Tax Assets	1,027,604	924,618
Deferred Tax Liabilities:		
Property, plant and equipment	(946,778)	(1,065,791)
Advance mining royalties	(44,921)	(37,621)
Gas hedge	(105,864)	(74,898)
Other	(4,670)	(5,331)
Total Deferred Tax Liabilities	(1,102,233)	(1,183,641)
Net Deferred Tax Liability	$(74,629)	$(259,023)

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As part of its simplification initiative, the FASB recently issued Update 2015-17 - Income Taxes: Balance Sheet Classification of Deferred Taxes that requires entities with a classified balance sheet to present all deferred tax assets and liabilities as noncurrent. The Accounting Standards Update allows entities to choose either prospective or retrospective transition. CONSOL Energy has chosen to early adopt this standard and to apply it retrospectively. For the year ended December 31, 2014, $66,569 of deferred tax assets were reclassified from Current Assets to offset Noncurrent Liabilities in the Consolidated Balance Sheets. For the year ended December 31, 2015, all deferred tax assets and liabilities are reported as noncurrent consistent with FASB guidance.

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. At December 31, 2015 and 2014, positive evidence considered included financial and tax earnings generated over the past three years for certain subsidiaries, reversals of financial to tax temporary differences and the implementation of and/or ability to employ various tax planning strategies. Negative evidence included financial and tax losses generated in prior periods and the inability to achieve forecasted results for those periods. CONSOL Energy continues to report, on an after federal tax basis, a deferred tax asset related to state operating losses of $76,171 with a related valuation allowance of $42,983 at December 31, 2015. The deferred tax asset related to state operating losses, on an after tax adjusted basis, was $49,638 with a related valuation allowance of $6,080 at December 31, 2014. A review of positive and negative evidence regarding these tax benefits concluded that the valuation allowances for various CONSOL Energy subsidiaries was warranted. The net operating losses expire at various times between 2016 and 2035. A valuation allowance on foreign tax credits of $25,903 has been recorded at December 31, 2015 and no valuation allowance was record at December 31, 2014. The foreign tax credits expire at various times between 2021 and 2023.

The deferred tax assets attributable to future deductible temporary differences for certain CONSOL Energy subsidiaries with histories of financial and tax losses were also reviewed for positive and negative evidence regarding the realization of the deferred tax assets. A valuation allowance of $9,420 and $16 on an after federal tax adjusted basis has also been recorded for 2015 and 2014, respectively. Management will continue to assess the potential for realizing deferred tax assets based upon income forecast data and the feasibility of future tax planning strategies and may record adjustments to valuation allowances against deferred tax assets in future periods, as appropriate, that could materially impact net income.

During 2015, the deferred tax asset relating to federal alternative minimum tax decreased $9,027. This change was due to 2015 business activity and the 2014 accrual to 2014 return adjustments.

The following is a reconciliation, stated as a percentage of pretax income, of the United States statutory federal income tax rate to CONSOL Energy's effective tax rate:

	For the Years Ended December 31,					
	2015		2014		2013	
	Amount	Percent	Amount	Percent	Amount	Percent
Statutory U.S. federal income tax rate	$(174,615)	35.0 %	$64,093	35.0 %	$16,126	35.0 %
Excess tax depletion	(31,906)	6.4	(43,140)	(23.6)	(51,104)	(110.9)
Effect of medicare prescription drug, improvement and modernization act of 2003	—	—	631	0.3	2,112	4.6
Effect of domestic production activities	—	—	(1,522)	(0.8)	5,680	12.3
Federal tax accrual to tax return reconciliation	15,453	(3.1)	(8,331)	(4.5)	(1,406)	(3.1)
IRS and state tax examination settlements	(36)	—	(5,124)	(2.8)	3	—
Net effect of state income taxes	(10,519)	2.1	5,249	2.9	(2,399)	(5.2)

Effect of change in federal valuation allowance	25,903	(5.2	)	—	—		—	—	
Effect of change in state valuation allowance	39,492	(7.9	)	(1,436	) (0.8	)	(4,659	) (10.1	)
Effect of foreign tax	1,011	(0.2	)	1,411	0.8		—	—	
Other	792	(0.2	)	2,516	1.3		2,458	5.3	
Income Tax (Benefit) Expense / Effective Rate	$(134,425)	26.9	%	$14,347	7.8	%	$(33,189	) (72.1	)%

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 $23,752 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 $31,370.

A reconciliation of the beginning and ending gross amounts of unrecognized tax benefits is as follows:

	For the Years Ended December 31,	
	2015	2014
Balance at beginning of period	$4,265	$34,786
Increase in unrecognized tax benefits resulting from tax positions taken during prior periods	8,437	4,265
Reduction in unrecognized tax benefits as a result of the lapse of the applicable statute of limitations	—	(2,540)
Reduction of unrecognized tax benefits as a result of a settlement with taxing authorities	—	(32,246)
Balance at end of period	$12,702	$4,265

If these unrecognized tax benefits were recognized, $4,265 would affect CONSOL Energy's effective income tax rate for 2015 and 2014.

CONSOL Energy and its subsidiaries file income tax returns in the United States and returns within various states and Canadian jurisdictions. With few exceptions, the Company is no longer subject to United States federal, state, local, or non-U.S. income tax examinations by tax authorities for the years before 2010.

In 2015, CONSOL Energy recognized an increase in unrecognized tax benefits of $8,437 for tax benefits resulting from a tax position taken on a state tax return.

CONSOL Energy recognizes interest accrued related to unrecognized tax benefits in its interest expense. As of December 31, 2015, the Company had an accrued liability of $53 for interest related to uncertain tax positions. At December 31, 2014, there was no accrued interest related to unrecognized tax positions. Interest expense of $53 and benefit of $6,200 was recorded in the Company's Consolidated Statements of Income for the years ended December 31, 2015 and 2014, respectively. During the year ended December 31, 2015, CONSOL Energy paid no interest related to income tax deficiencies. During the year ended December 31, 2014, CONSOL Energy paid $835 and $141 of interest related to income tax deficiencies for tax years 2008 and 2009, respectively.

CONSOL Energy recognizes penalties accrued related to uncertain tax positions in its income tax expense. As of December 31, 2015 and 2014, CONSOL Energy had no accrued liabilities for tax penalties.

NOTE 8—MINE CLOSING, RECLAMATION & GAS WELL CLOSING:

CONSOL Energy accrues for reclamation, mine closing costs, perpetual water care costs and dismantling and removing costs of natural gas related facilities using the accounting treatment prescribed by the Asset Retirement and Environmental Obligations Topic of the FASB Accounting Standards Codification. CONSOL Energy recognizes capitalized asset retirement costs by increasing the carrying amount of related long-lived assets. The obligation for asset retirements is included in Mine Closing, Reclamation, Gas Well Closing and Other Accrued Liabilities on the Consolidated Balance Sheets.

The reconciliation of changes in the asset retirement obligations at December 31, 2015 and 2014 is as follows:

	As of December 31,	
	2015	2014
Balance at beginning of period	$575,529	$600,875
Accretion expense	41,899	42,608
Payments	(36,105)	(52,339)
Revisions in estimated cash flows	(26,433)	(2,069)
Other	(5,286)	(13,546)
Balance at end of period	$549,604	$575,529

For the year ended December 31, 2015, Other includes ($2,133) related to the disposition of two Perpetual Care sites as part of the WAE sale (see Note 3 - Acquisitions and Dispositions for more information), and ($2,355) related to the disposition of the non-producing Emery Mine. For the year ended December 31, 2014, Other includes ($9,221) related to the disposition of the non-producing Hamilton Nos. 1 and 2 Mines, and ($4,325) related to the completion of this transfer of permits at the former Jones Fork Mines.

NOTE 9—INVENTORIES:

	December 31,	
	2015	2014
Coal	$21,495	$19,242
Supplies	75,943	82,631
Total Inventories	$97,438	$101,873

NOTE 10—ACCOUNTS RECEIVABLE SECURITIZATION:

CONSOL Energy and certain of its U.S. subsidiaries were party to a trade accounts receivable facility with financial institutions for the sale on a continuous basis of eligible trade accounts receivable. This facility was terminated on July 7, 2015.

CNX Funding Corporation, a wholly owned, special purpose, bankruptcy-remote subsidiary, bought and sold eligible trade receivables generated by certain subsidiaries of CONSOL Energy. Under the receivables facility, CONSOL Energy and certain subsidiaries, irrevocably and without recourse, sold all of their eligible trade accounts receivable to CNX Funding Corporation, who in turn sold these receivables to financial institutions and their affiliates, while maintaining a subordinated interest in a portion of the pool of trade receivables. This retained interest, which was included in Accounts and Notes Receivable Trade in the Consolidated Balance Sheets, was recorded at fair value. Due to a short average collection cycle for such receivables, CONSOL Energy's collection experience history and the composition of the designated pool of trade accounts receivable that were part of this program, the fair value of its retained interest approximated the total amount of the designated pool of accounts receivable. CONSOL Energy serviced the sold trade receivables for the financial institutions for a fee based upon market rates for similar services.

In accordance with the Transfers and Servicing Topic of the Financial Accounting Standards Board (FASB) Accounting Standards Codification, CONSOL Energy recorded transactions under the securitization facility as secured borrowings on the Consolidated Balance Sheets. The pledge of collateral was reported as Accounts Receivable - Securitized and the borrowings were classified as debt in Borrowings under Securitization Facility.

At December 31, 2014, eligible accounts receivable totaled $77,800. After taking into account outstanding letters of credit of $60,230, there remained $17,570 in subordinated retained interest at December 31, 2014. These changes were reflected in the Net Cash Used in Financing Activities section of the Consolidated Statement of Cash Flows. There were no borrowings under the securitization facility recorded on the Consolidated Balance Sheets at December 31, 2014. The outstanding borrowings at June 30, 2015 were repaid and the outstanding letters of credit at June 30, 2015 were transferred against the revolving credit facility upon termination on July 7, 2015.

The cost of funds under this facility was based upon LIBOR and commercial paper rates, plus a charge for administrative services paid to the financial institutions. Costs associated with the receivables facility totaled $432, $892 and $1,737 for the years ended December 31, 2015, 2014 and 2013, respectively. These costs were recorded as financing fees which are included in Other Costs - Miscellaneous Operating Expense in the Consolidated Statements of Income.

NOTE 11—PROPERTY, PLANT AND EQUIPMENT:

	December 31,	
E&P Property, Plant and Equipment	2015	2014
Intangible drilling cost	$3,452,989	$2,798,394
Proved gas properties	1,922,602	1,768,007
Unproved gas properties	1,421,083	1,540,835
Gas gathering equipment	1,147,173	1,088,238
Gas wells and related equipment	785,744	716,748
Other gas assets	125,703	123,539
Gas advance royalties	19,745	20,580
Total E&P Property, Plant and Equipment	8,875,039	8,056,341
Less: Accumulated Depreciation, Depletion and Amortization	2,695,674	1,523,760
Total E&P Property, Plant and Equipment - Net	6,179,365	6,532,581
Coal and Other Property, Plant and Equipment:		
Coal and other plant and equipment	3,797,361	3,726,514
Coal properties and surface lands	1,365,976	1,358,306
Airshafts	481,841	468,924
Mine development	405,282	414,501
Coal advance mining royalties	387,425	386,245
Leased coal lands	262,022	263,946
Total Coal and Other Property, Plant and Equipment	6,699,907	6,618,436
Less: Accumulated Depreciation, Depletion and Amortization	3,209,895	2,988,545
Total Coal and Corporate Property, Plant and Equipment - Net	3,490,012	3,629,891
Total Company Property, Plant and Equipment	15,574,946	14,674,777
Less - Total Company Accumulated Depreciation, Depletion and Amortization	5,905,569	4,512,305
Total Company Property, Plant and Equipment - Net	$9,669,377	$10,162,472

The following assets are amortized using the units-of-production method. Amounts reflect properties where mining or drilling operations have not yet commenced and therefore, are not being amortized for the years ended December 31, 2015 and 2014, respectively.

	December 31,	
	2015	2014
Unproved gas properties	$1,421,083	$1,540,835
Coal properties	465,988	477,444
Coal advance mining royalties	59,565	52,009
Airshafts	50,262	52,194
Leased coal lands	47,759	50,044
Gas advance royalties	19,745	20,580
Mine development	11,592	11,984
Total	$2,075,994	$2,205,090

As of December 31, 2015 and 2014, plant and equipment includes gross assets under capital lease of $81,624 and $87,055, respectively. Included in Gas gathering equipment under the E&P division is a capital lease for the Jewell Ridge Pipeline of $66,919 at December 31, 2015 and 2014 . The E&P division also maintains a capital lease for vehicles of $7,474 and $10,207 at December 31, 2015 and 2014 , respectively, which are included in Other gas assets. At December 31, 2015 and 2014, the All Other segment maintains capital leases for vehicles and computer equipment of $7,231 and $9,929, respectively, which are included in Coal and other plant and equipment. Accumulated amortization for capital leases was $47,909 and $49,735 at December 31, 2015 and 2014,

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respectively. Amortization expense for capital leases is included in Depreciation, Depletion and Amortization in the Consolidated Statements of Income. See Note 15–Leases for further discussion of capital leases.

Industry Participation Agreements

CONSOL Energy has two significant industry participation agreements (referred to as "joint ventures" or "JVs") that provided drilling and completion carries for our retained interests.

CNX Gas Company is party to a joint development agreement with Hess Ohio Developments, LLC (Hess) with respect to approximately 155 thousand net Utica Shale acres in Ohio in which each party has a 50% undivided interest. Under the agreement, as amended, Hess is obligated to pay a total of approximately $335,000 in the form of a 50% drilling carry of certain CONSOL Energy working interest obligations as the acreage is developed. As of December 31, 2015, Hess' remaining carry obligation is $1,747.

CNX Gas Company is party to a joint development agreement with Noble Energy, Inc. (Noble) with respect to approximately 700 thousand net Marcellus Shale oil and gas acres in West Virginia and Pennsylvania, in which each party owns a 50% undivided interest. Under the agreement, as amended, Noble Energy is obligated to pay a total of approximately $1,846,000 in the form of a one-third drilling carry of certain of CONSOL Energy's working interest obligations as the property is developed, subject to certain limitations. These limitations include the suspension of the carry if average Henry Hub natural gas prices are below $4.00 per million British thermal units (MMbtu) for three consecutive months. The carry was in effect from March 1, 2014, and remained effective until November 1, 2014 when average natural gas prices had been below $4.00/MMbtu for the three prior months and continues to be suspended. Restrictions also include a $400,000 annual maximum on Noble Energy's carried cost obligation. As of December 31, 2015, Noble Energy's remaining carry obligation is approximately $1,624,448.

NOTE 12—SHORT-TERM NOTES PAYABLE:

CONSOL Energy's current senior secured credit agreement expires on June 18, 2019. The credit facility allows for up to $2,000,000 of borrowings, which includes a $750,000 letters of credit sub-limit. CONSOL Energy can also request an additional $500,000 increase in the aggregate borrowing limit amount.

The current facility is secured by substantially all of the assets of CONSOL Energy and certain of its subsidiaries. Fees and interest rate spreads are based on the percentage of facility utilization, measured quarterly. Availability under the facility is limited to a borrowing base, which is determined by the lenders syndication agent and approved by the required number of lenders in good faith by calculating a value of CONSOL Energy's proved natural gas reserves.

The current facility contains a number of affirmative and negative covenants that limit the Company's ability to dispose of assets, make investments, purchase or redeem CONSOL Energy common stock, pay dividends, merge with another corporation and amend, modify or restate the senior unsecured notes. In May 2015, the facility was amended to allow, among other things, spinoffs, or other public equity offering transactions, in regard to subsidiaries that own metallurgical coal assets and thermal coal assets, and all arrangements, actions and transactions in connection therewith, including releases of associated entities or assets from the Credit Agreement and any liens granted under the loan documents. The Amendment also permits the incurrence of a term loan facility up to the aggregate principal amount of $600,000 at subsidiaries of the Company that own the thermal coal assets and the incurrence of a revolving credit facility up to an aggregate principal amount of $300,000 at subsidiaries of the Company that own the metallurgical coal assets. In November 2015, the Company's lending group reaffirmed the borrowing base of the facility.

The facility also requires that CONSOL Energy maintains a minimum interest coverage ratio of 2.50 to 1.00, which is calculated as the ratio of Adjusted EBITDA to cash interest expense of CONSOL Energy and certain of its subsidiaries, measured quarterly. CONSOL Energy must also maintain a minimum current ratio of 1.00 to 1.00, which is calculated as the ratio of current assets, plus revolver availability, to current liabilities excluding borrowings under the revolver, measured quarterly. At December 31, 2015, the interest coverage ratio was 5.32 to 1.00 and the current ratio was 2.29 to 1.00. Further, the credit facility allows unlimited investments in joint ventures for the development and operation of natural gas gathering systems and permits CONSOL Energy to separate its E&P and coal businesses if the leverage ratio (which is, essentially, the ratio of debt to EBITDA) of the E&P business immediately after the separation would not be greater than 2.75 to 1.00. The calculation of all of the ratios above exclude CNXC.

At December 31, 2015, the $2,000,000 facility had $952,000 of borrowings outstanding and $258,177 of letters of credit outstanding, leaving $789,823 of unused capacity. At December 31, 2014, the $2,000,000 facility had no borrowings outstanding and $244,418 of letters of credit outstanding, leaving $1,755,582 of unused capacity.

NOTE 13—OTHER ACCRUED LIABILITIES:

	December 31,	
	2015	2014
Subsidence liability	$87,682	$103,343
Royalties	40,297	52,456
Accrued Interest	38,406	51,404
Accrued payroll and benefits	30,657	37,293
Equipment leases	15,286	15,258
Accrued other taxes	15,172	17,951
Columbia Energy Ventures Majorsville Sublease	8,349	49,533
Short-term incentive compensation	7,714	36,272
Other	78,391	85,026
Current portion of long-term liabilities:		
Postretirement benefits other than pensions	46,105	57,279
Mine closing	30,560	32,222
Gas well closing	15,648	21,286
Workers' compensation	14,803	15,122
Pneumoconiosis benefits	9,471	9,156
Reclamation	5,332	6,075
Long-term disability	4,248	3,957
Salary retirement	2,772	9,339
Total Other Accrued Liabilities	$450,893	$602,972

NOTE 14—LONG-TERM DEBT:

	December 31,	
	2015	2014
Debt:		
Senior Notes due April 2022 at 5.875% (Principal of $1,850,000 plus Unamortized Premium of $5,617 and $6,506, Respectively)	$1,855,617	$1,856,506
Senior Notes due April 2023 at 8.00% (Principal of $500,000 less Unamortized Discount of $6,561)	493,439	—
Revolving Credit Facility - CNX Coal Resources LP	185,000	—
MEDCO Revenue Bonds in Series due September 2025 at 5.75%	102,865	102,865
Senior Notes due April 2020 at 8.25%, Issued at Par Value	74,470	1,014,800
Senior Notes due March 2021 at 6.375%, Issued at Par Value	20,611	250,000
Advance Royalty Commitments (16.35% and 7.91% Weighted Average Interest Rate, Respectively)	9,960	13,473
Other Long-Term Note Maturing in 2018 (Principal of $3,096 and $4,473 less Unamortized Discount of $327 and $643, Respectively)	2,769	3,830
Less: Unamortized Debt Issuance Costs	33,017	38,315
	2,711,714	3,203,159
Less: Amounts due in one year *	(1,197)	(761)
Long-Term Debt	$2,712,911	$3,203,920

* Represents $3,225 and $5,052 due in one year, less $4,422 and $5,813 of unamortized debt issuance costs at December 31, 2015 and 2014, respectively. Excludes current portion of Capital Lease Obligations of $7,847 and $7,963 at December 31, 2015 and 2014, respectively.

In April 2015, FASB issued Update 2015-03 - Interest-Imputation of Interest: Simplifying the Presentation of Debt Issuance Costs. To simplify the presentation of debt issuance costs, the amendments in this Update require that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct reduction from the carrying amount of that debt liability, consistent with debt discounts. This guidance is effective for fiscal years beginning after December 15, 2015 and is required to

be applied retrospectively to all prior periods presented. As permitted by the Update, CONSOL Energy elected to early adopt this guidance beginning in the fourth quarter of fiscal year 2015. The resulting reclassification of unamortized debt issuance costs from Other Assets to Long-Term Debt, net of the current portion, in the Consolidated Balance Sheets was $28,595 and $32,502 as of December 31, 2015 and 2014, respectively.

Annual undiscounted maturities on long-term debt during the next five years and thereafter are as follows:

Year ended December 31,	Amount
2016	$3,457
2017	3,164
2018	1,404
2019	185,899
2020	75,225
Thereafter	2,476,852
Total Long-Term Debt Maturities	$2,746,001

On March 30, 2015, CONSOL Energy closed on the private placement of $500,000 of 8.00% senior notes due in 2023 (the "2023 Notes") less $7,240 of unamortized bond discount. The 2023 Notes are guaranteed by substantially all of CONSOL Energy's wholly-owned domestic restricted subsidiaries. CONSOL Energy used the net proceeds of the sale of the 2023 Notes, together with borrowings under its revolving credit facility, to purchase $937,822 of its outstanding 8.25% senior notes due in 2020 and $229,176 of its outstanding 6.375% senior notes due in 2021. As part of this transaction, $67,734 loss on extinguishment was incurred and is included in Loss on Debt Extinguishment in the Consolidated Statements of Income.

On April 7, 2015, CONSOL Energy purchased $2,508 of its outstanding 8.25% senior notes due in 2020 and $213 of its outstanding 6.375% senior notes due in 2021. As part of this transaction, $17 loss on extinguishment was incurred and is included in Loss on Debt Extinguishment in the Consolidated Statements of Income.

On July 7, 2015, CNXC, a consolidated subsidiary of CONSOL Energy, entered into a Credit Agreement for a $400,000 revolving credit facility. As of December 31, 2015, CNXC had $185,000 of borrowings outstanding on the facility. CONSOL Energy is not a guarantor of CNXC's revolving credit facility. See Note 27 - Related Party Transactions for more information.

On April 16, 2014, CONSOL Energy purchased all the 8.00% senior notes that were due in 2017 at a price equal to 104.0% of the principal amount. As part of this transaction, $74,277 loss on extinguishment was incurred and is included in Loss on Debt Extinguishment on the Consolidated Statements of Income.

On August 12, 2014, CONSOL Energy closed on an additional $250,000 of its 5.875% senior notes due in 2022 at a price equal to 102.75% of the principal amount of the additional notes. CONSOL Energy used $235,200 of the net proceeds of the sale of the additional notes to purchase a portion of the outstanding 8.25% senior notes due in 2020 at price equal to 107.5% of the principal amount. As part of this transaction, $20,990 loss on extinguishment was incurred and is included in Loss on Debt Extinguishment in the Consolidated Statements of Income.

NOTE 15—LEASES:

CONSOL Energy uses various leased facilities and equipment in our operations. Future minimum lease payments under capital and operating leases, together with the present value of the net minimum capital lease payments, at December 31, 2015, are as follows:

	Capital Leases	Operating Leases
Year Ended December 31,		
2016	$10,592	$95,454
2017	9,681	87,986
2018	9,285	63,667
2019	8,653	28,725
2020	7,620	17,149
Thereafter	6,090	70,891
Total minimum lease payments	$51,921	$363,872
Less amount representing interest (1.62% – 7.36%)	8,780	
Present value of minimum lease payments	43,141	
Less amount due in one year	7,847	
Total Long-Term Capital Lease Obligation	$35,294	

Rental expense under operating leases was $124,569, $126,078, and $90,128 for the years ended December 31, 2015, 2014 and 2013, respectively.

At December 31, 2015, certain of the above operating leases for mining equipment are subleased to third-parties. The following represents the minimum rental payments for those operating subleases:

2016	2017	2018	2019	2020	Thereafter	Total
$ 26,685	$ 26,685	$ 26,685	$ 13,343	$ —	$ —	$ 93,398

CONSOL Energy leases certain owned mining equipment to a third-party under operating leases. The owned equipment included in gross property, plant and equipment was $31,059, with $12,424 accumulated depreciation at December 31, 2015.

At December 31, 2015, scheduled minimum rental payments for operating leases related to this equipment were as follows:

2016	2017	2018	2019	2020	Thereafter	Total
$ 7,425	$ 4,496	$ 2,992	$ 1,701	$ 627	$ —	$ 17,241

NOTE 16—PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS:
Pension:

CONSOL Energy has non-contributory defined benefit retirement plans. Effective December 31, 2015, CONSOL's qualified defined benefit retirement plans have been frozen.The benefits for these plans are based primarily on years of service and employees' pay. CONSOL Energy's qualified pension plan allows for lump-sum distributions of benefits earned up until December 31, 2005, at the employees' election.

On September 30, 2014, the qualified pension plan was remeasured to reflect an announced plan amendment that would reduce future accruals of pension benefits as of January 1, 2015. The plan amendment called for a hard freeze of the qualified defined benefit pension plan on January 1, 2015 for employees who were under age 40 or had less than 10 years of service as of September 30, 2014. Employees who were age 40 or over and had at least 10 years of service would continue in the defined benefit pension plan unchanged. The modifications to the pension plan resulted in a $21,624 reduction in the pension liability with a corresponding adjustment of $13,659 in Other Comprehensive Income, net of $7,965 in deferred taxes. Additionally, a curtailment gain of $549 was recognized with a corresponding adjustment of $347 in Other Comprehensive Income, net of $202 in deferred taxes.

On August 31, 2015, the qualified pension plan was remeasured to reflect another announced plan amendment that eliminated future accruals of pension benefits as of January 1, 2016. The plan amendment called for a hard freeze of the qualified defined benefit pension plan on January 1, 2016 for all remaining participants in the plan. The modifications to the pension plan resulted in a $26,352 reduction in the pension liability with a corresponding adjustment of $16,752 in Other Comprehensive Income, net of $9,600 in deferred taxes. Additionally, a curtailment loss of $5 was recognized with a corresponding adjustment of $3 in Other Comprehensive Income, net of $2 in deferred taxes. The amendment resulted in a remeasurement of the qualified pension plan at August 31, 2015. The remeasurement resulted in a change to the discount rate to 4.40% from 4.07% used at December 31, 2014. The remeasurement increased the pension liability by $17,793 with a corresponding adjustment of $11,106 in Other Comprehensive Income, net of $6,687 in deferred taxes.

According to the Defined Benefit Plans Topic of the Financial Accounting Standards Board (FASB) Accounting Standards Codification, if the lump sum distributions made during a plan year, which for CONSOL Energy is January 1 to December 31, exceed the total of the projected service cost and interest cost for the plan year, settlement accounting is required. Lump sum payments exceeded this threshold during the years ended December 31, 2015, 2014, and 2013. Accordingly, CONSOL Energy recognized expense of $19,053, $29,095, and $39,482 for the years ended December 31, 2015, 2014, and 2013 respectively, in Other Costs - Miscellaneous Operating Expense in the Consolidated Statements of Income. The settlement charges represented a pro rata portion of the net unrecognized loss based on the percentage reduction in the projected benefit obligation due to the lump sum payments. The settlement charges also resulted in remeasurements of the pension plan throughout 2015, 2014 and 2013.

In the third quarter of 2015, CONSOL Energy remeasured its pension plan as a result of the previously discussed plan amendment. In conjunction with this remeasurement, the method used to estimate the service and interest components of net periodic benefit cost for pension was changed. This change was also made to other postretirement benefits in the fourth quarter during the annual remeasurement of that plan. This change, compared to the previous method, resulted in a decrease in the service and interest components for pension cost in the third quarter and other postretirement benefits in the fourth quarter. Historically, CONSOL Energy estimated these service and interest cost components utilizing a single weighted-average discount rate derived from the yield curve used to measure the benefit obligation at the beginning of the period. CONSOL Energy has elected to utilize a full yield curve approach in the estimation of these components by applying the specific spot rates along the yield curve used in the determination of the benefit obligation to the relevant projected cash flows. This change was made to provide a more precise measurement of service and interest costs by improving the correlation between projected benefit cash flows to the

corresponding spot yield curve rates. This change does not affect the measurement of the total benefit obligations. CONSOL Energy has accounted for this change as a change in accounting estimate that is inseparable from a change in accounting principle and accordingly, has accounted for it prospectively.

In April 2015, the FASB issued Updated 2015-04 - Compensation-Retirement Benefits (Topic 715): Practical Expedient for the Measurement Date of an Employer's Defined Benefit Obligation and Plan Assets. For an entity that has a significant event in an interim period that calls for a remeasurement of defined benefit plan assets and obligations, the amendments in this Update also provide a practical expedient that permits the entity to remeasure defined benefit plan assets and obligations using the month-end that is closest to the date of the significant event. As permitted by this Update, CONSOL Energy has elected to early adopt this guidance.

Other Postretirement Benefit Plans:

Certain subsidiaries of CONSOL Energy provide medical and prescription drug benefits to retired employees not covered by the Coal Industry Retiree Health Benefit Act of 1992 (The Coal Act). Represented hourly employees are eligible to participate based upon the terms of the National Bituminous Coal Wage Agreement of 2011, or "The Coal Act".

On September 30, 2014, the Salaried OPEB plan and Production and Maintenance (P&M) OPEB plans were remeasured to reflect an announced plan amendment that would reduce retiree medical and life insurance benefits as of September 30, 2014. Effective September 30, 2014, no retiree medical or life benefits were to be provided to active employees. Salaried and P&M retirees as of September 30, 2014 were to continue in the OPEB plans for a maximum period up to December 31, 2019, and coverage thereafter was eliminated (see below for information on an additional amendment made to these plans in 2015). The Company elected to make cash transition payments totaling approximately $46,282 to the active employees whose retiree medical, prescription drug, and life insurance benefits were eliminated by the changes to the OPEB plans. These cash payments are not considered to be post-retirement benefits, and as such, they are not reflected in the actuarial calculations related to the OPEB plans. The amendment to the OPEB plans resulted in a $315,439 reduction in the OPEB liability with a corresponding adjustment of $199,252 in Other Comprehensive Income, net of $116,187 in deferred taxes. A curtailment gain of $35,633 was recognized in September 2014 with a corresponding adjustment of $22,508 in Other Comprehensive Income, net of $13,125 in deferred taxes. The amendment also resulted in a remeasurement of the OPEB plan at September 30, 2014.

On May 31, 2015, the Salaried and P&M OPEB plans were remeasured to reflect another plan amendment. Retirees continued to participate in the Salaried and P&M OPEB plans until December 31, 2015, and coverage thereafter has been eliminated. The amendment to the OPEB plans resulted in a $43,598 reduction in the OPEB liability with a corresponding increase of $27,716 in Other Comprehensive Income, net of $15,882 in deferred taxes. This amendment resulted in a remeasurement of the OPEB plan at May 31, 2015. The remeasurement resulted in a change to the discount rate to 1.60% for the Salaried OPEB plan and 1.65% for the P&M OPEB plan from 1.78% and 1.84%, respectively, used at December 31, 2014. The remeasurement decreased the OPEB liability by $1,070 with a corresponding increase of $680 in Other Comprehensive Income, net of $390 in deferred taxes. CONSOL Energy recognized income of $235,541 related to amortization of prior service credit, coupled with recognition of actuarial losses in Operating and Other Costs - Coal in the Consolidated Statements of Income for the year ended December 31, 2015 as a result of the changes made to the Salaried and P&M OPEB plans.
On December 5, 2013, CONSOL Energy completed the sale of its wholly-owned subsidiary Consolidation Coal Company and certain other subsidiaries to Murray Energy Corporation (the CCC Sale). As a result of the CCC Sale, the obligations for certain participants of the OPEB Plan are the primary responsibility of Murray Energy. This reduced CONSOL Energy's OPEB liability by $1,891,057 at December 31, 2013. These plan settlements resulted in adjustments of $339,318 in Other Comprehensive Income, net of $203,610 in deferred taxes at December 31, 2013. As the result of corporate staffing reductions associated with the sale, the Pension and OPEB plans also recognized curtailment gains of $374 and $39,650, respectively, for the year ended December 31, 2013. The curtailment gains resulted in adjustments of $231 and $24,515 in Other Comprehensive Income, net of $143 and $15,135 in deferred taxes for the Pension Plan and the OPEB plan, respectively, at December 31, 2013.

The reconciliation of changes in the benefit obligation, plan assets and funded status of these plans at December 31, 2015 and 2014, is as follows:

	Pension Benefits at December 31,		Other Postretirement Benefits at December 31,	
	2015	2014	2015	2014
Change in benefit obligation:				
Benefit obligation at beginning of period	$870,471	$812,644	$760,959	$1,021,974
Service cost	8,653	17,187	—	7,089
Interest cost	32,095	35,363	27,238	44,177
Actuarial (gain) loss	(39,563)	136,995	(9,224)	66,695
Plan amendments	—	—	(43,598)	(315,439)
Plan transfer*	—	—	(5,242)	—
Plan curtailments	(26,352)	(21,624)	—	—
Plan settlements	(51,497)	(82,776)	—	—
Participant contributions	—	—	1,649	1,643
Benefits and other payments	(30,400)	(27,318)	(60,027)	(65,180)
Benefit obligation at end of period	$763,407	$870,471	$671,755	$760,959
Change in plan assets:				
Fair value of plan assets at beginning of period	$751,176	$768,831	$—	$—
Actual (loss) return on plan assets	(9,293)	66,025	—	—
Company contributions	9,053	26,414	58,378	63,537
Participant contributions	—	—	1,649	1,643
Benefits and other payments	(30,400)	(27,318)	(60,027)	(65,180)
Plan settlements	(51,497)	(82,776)	—	—
Fair value of plan assets at end of period	$669,039	$751,176	$—	$—
Funded status:				
Current liabilities	$(2,772)	$(9,339)	$(40,863)	$(57,279)
Noncurrent liabilities	(91,596)	(109,956)	(630,892)	(703,680)
Net obligation recognized	$(94,368)	$(119,295)	$(671,755)	$(760,959)
Amounts recognized in accumulated other comprehensive income consist of:				
Net actuarial loss	$288,695	$334,362	$367,920	$471,085
Prior service credit	(2,201)	(2,862)	—	(292,728)
Net amount recognized (before tax effect)	$286,494	$331,500	$367,920	$178,357

*The plan transfer relates to the IBNR (incurred but not reported) costs associated with the terminated Salaried and P&M OPEB plans. These costs are now included in Other Accrued Liabilities in the Consolidated Balance Sheets.

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The components of net periodic benefit costs are as follows:

	Pension Benefits For the Years Ended December 31,			Other Postretirement Benefits For the Years Ended December 31,		
	2015	2014	2013	2015	2014	2013
Components of net periodic benefit cost:						
Service cost	$8,653	$17,187	$20,865	$—	$7,089	$18,680
Interest cost	32,095	35,363	36,829	27,238	44,177	111,687
Expected return on plan assets	(51,528)	(51,400)	(51,814)	—	—	—
Amortization of prior service (credits)	(666)	(1,217)	(1,611)	(336,327)	(21,163)	(30,552)
Recognized net actuarial loss	21,519	23,927	37,853	102,875	28,682	66,417
Curtailment loss (gain)	5	(549)	(374)	—	(35,633)	(39,650)
Settlement loss (gain)	19,053	29,095	39,482	(8,932)	—	(1,348,129)
Net periodic benefit cost (credit)	$29,131	$52,406	$81,230	$(215,146)	$23,152	$(1,221,547)

Expenses (income) attributable to discontinued operations included in the net periodic cost (credit) above (including settlements and curtailments associated with the CCC Sale) were $8,231 for the year ended December 31, 2013 for the Pension Plans and $(1,293,975) for the year ended December 31, 2013 for the OPEB Plans. There were no expenses attributable to discontinued operations in 2015 and 2014.

Amounts included in accumulated other comprehensive loss which are expected to be recognized in 2016 net periodic benefit costs:

	Pension Benefits	Other Postretirement Benefits
Prior service credit recognition	$(590)	$—
Actuarial loss recognition	$8,465	$19,168

CONSOL Energy utilizes a corridor approach to amortize actuarial gains and losses that have been accumulated under the Pension Plan. Cumulative gains and losses that are in excess of 10% of the greater of either the projected benefit obligation (PBO) or the market-related value of plan assets are amortized over the expected average remaining future service of the current active membership for the Pension plan.

CONSOL Energy also utilizes a corridor approach to amortize actuarial gains and losses that have been accumulated under the OPEB Plan. Cumulative gains and losses that are in excess of 10% of the greater of either the accumulated postretirement benefit obligation (APBO) or the market-related value of plan assets are amortized over the average future remaining lifetime of the current inactive population for the UMWA OPEB plan.

The following table provides information related to pension plans with an accumulated benefit obligation in excess of plan assets:

	As of December 31,	
	2015	2014
Projected benefit obligation	$763,407	$870,471
Accumulated benefit obligation	$761,124	$834,811
Fair value of plan assets	$669,039	$751,176

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Assumptions:

The weighted-average assumptions used to determine benefit obligations are as follows:

	Pension Benefits For the Year Ended December 31,		Other Postretirement Benefits For the Year Ended December 31,	
	2015	2014	2015	2014
Discount rate	4.50 %	4.07 %	4.50 %	3.80 %
Rate of compensation increase	3.80 %	3.80 %	—	—

The discount rates are determined using a Company-specific yield curve model (above-mean) developed with the assistance of an external actuary. The Company-specific yield curve models (above-mean) use a subset of the expanded bond universe to determine the Company-specific discount rate. Bonds used in the yield curve are rated AA by Moody's or Standard & Poor's as of the measurement date. The yield curve models parallel the plans' projected cash flows, and the underlying cash flows of the bonds included in the models exceed the cash flows needed to satisfy the Company plans.

The weighted-average assumptions used to determine net periodic benefit costs are as follows:

	Pension Benefits at December 31,			Other Postretirement Benefits at December 31,		
	2015	2014	2013	2015	2014	2013
Discount rate	4.07 %	4.87 %	4.00 %	4.03 %	4.88 %	4.05 %
Expected long-term return on plan assets	7.75 %	7.75 %	7.75 %	—	—	—
Rate of compensation increase	3.80 %	4.21 %	3.77 %	—	—	—

The long-term rate of return is the sum of the portion of total assets in each asset class held multiplied by the expected return for that class, adjusted for expected expenses to be paid from the assets. The expected return for each class is determined using the plan asset allocation at the measurement date and a distribution of compound average returns over a 20-year time horizon. The model uses asset class returns, variances and correlation assumptions to produce the expected return for each portfolio. The return assumptions used forward-looking gross returns influenced by the current Treasury yield curve. These returns recognize current bond yields, corporate bond spreads and equity risk premiums based on current market conditions.

The assumed health care cost trend rates are as follows:

	At December 31,		
	2015	2014	2013
Health care cost trend rate for next year	6.03 %	6.03 %	6.17 %
Rate to which the cost trend is assumed to decline (ultimate trend rate)	4.50 %	4.50 %	4.50 %
Year that the rate reaches ultimate trend rate	2026	2026	2026

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

	1-Percentage Point Increase	1-Percentage Point Decrease
Effect on total of service and interest cost components	$3,374	$(2,819)
Effect on accumulated postretirement benefit obligation	$80,300	$(67,646)

Assumed discount rates also have a significant effect on the amounts reported for both pension and other benefit costs. A one-quarter percentage point change in assumed discount rate would have the following effect on benefit costs:

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	0.25 Percentage Point Increase	0.25 Percentage Point Decrease
Pension benefit costs (decrease) increase	$(979)	$1,006
Other postemployment benefits costs (decrease) increase	$(320)	$318

Plan Assets:

The company's overall investment strategy is to meet current and future benefit payment needs through diversification across asset classes, fund strategies and fund managers to achieve an optimal balance between risk and return and between income and growth of assets through capital appreciation. Consistent with the objectives of the Trust and in consideration of the Trust's current funded status and the current level of market interest rates, the Retirement Board has approved an asset allocation strategy that will change over time in response to future improvements in the Trust's funded status and/or changes in market interest rates. Such changes in asset allocation strategy are intended to allocate additional assets to the fixed income asset class should the Trust's funded status improve. In this framework, the current target allocation for plan assets are 26 percent U.S. equity securities, 16.5 percent non-U.S. equity securities, 7.5 percent global equity securities, and 50 percent fixed income. Both the equity and fixed income portfolios are comprised of both active and passive investment strategies. The Trust is primarily invested in Mercer Common Collective Trusts. Equity securities consist of investments in large and mid/small cap companies with non-U.S. equities being derived from both developed and emerging markets. Fixed income securities consist of U.S. as well as international instruments, including emerging markets. The core domestic fixed income portfolios invest in government, corporate, asset-backed securities and mortgage-backed obligations. The average quality of the fixed income portfolio must be rated at least "investment grade" by nationally recognized rating agencies. Within the fixed income asset class, investments are invested primarily across various strategies such that its overall profile strongly correlates with the interest rate sensitivity of the Trust's liabilities in order to reduce the volatility resulting from the risk of changes in interest rates and the impact of such changes on the Trust's overall financial status. Derivatives, interest rate swaps, options and futures are permitted investments for the purpose of reducing risk and to extend the duration of the overall fixed income portfolio; however, they may not be used for speculative purposes. All or a portion of the assets may be invested in mutual funds or other commingled vehicles so long as the pooled investment funds have an adequate asset base relative to their asset class; are invested in a diversified manner; and have management and/or oversight by an Investment Advisor registered with the SEC. The Retirement Board, as appointed by the CONSOL Energy Board of Directors, reviews the investment program on an ongoing basis including asset performance, current trends and developments in capital markets, changes in Trust liabilities and ongoing appropriateness of the overall investment policy.

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The fair values of plan assets at December 31, 2015 and 2014 by asset category are as follows:

	Fair Value Measurements at December 31, 2015				Fair Value Measurements at December 31, 2014			
	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Asset Category								
Cash/Accrued Income	$631	$631	$—	$ —	$650	$650	$—	$ —
US Equities (a)	10	10	—	—	12	12	—	—
Mercer Collective Trusts								
US Large Cap Growth Equity (b)	39,426	—	39,426	—	53,617	—	53,617	—
US Large Cap Value Equity (c)	38,599	—	38,599	—	53,090	—	53,090	—
US Small/Mid Cap Growth Equity (d)	19,120	—	19,120	—	27,642	—	27,642	—
US Small/Mid Cap Value Equity (e)	19,345	—	19,345	—	26,473	—	26,473	—
US Core Fixed Income (f)	37,157	—	37,157	—	36,681	—	36,681	—
Non-US Core Equity (g)	89,923	—	89,923	—	115,783	—	115,783	—
Emerging Markets Equity (h)	18,786	—	18,786	—	27,150	—	27,150	—
Global Low Volatility Equity (i)	49,537	—	49,537	—	68,481	—	68,481	—
US Long Duration Investment Grade Fixed Income (j)	53,688	—	53,688	—	57,713	—	57,713	—
US Long Duration Fixed Income (k)	40,012	—	40,012	—	34,728	—	34,728	—
US Large Cap Passive Equity (l)	55,656	—	55,656	—	75,219	—	75,219	—
US Passive Fixed Income (m)	20,059	—	20,059	—	21,511	—	21,511	—
US Long Duration Passive Fixed Income (n)	39,914	—	39,914	—	33,149	—	33,149	—
US Ultra Long Duration Fixed Income (o)	11,663	—	11,663	—	12,555	—	12,555	—
US Active Long Corporate Investment (p)	131,832	—	131,832	—	101,420	—	101,420	—
Long Strips Fixed Income (q)	3,681	—	3,681	—	3,276	—	3,276	—
Opportunistic Fixed Income (r)	—	—	—	—	2,026	—	2,026	—

Total	$669,039	$641	$668,398	$ —	$751,176	$662	$750,514	$ —

(a) This category includes investments in US common stocks and corporate debt.

(b) This category invests primarily in common stock of large cap companies in the U.S. with above average earnings growth and revenue expectations. It targets broad diversification across economic sectors and seeks to achieve lower overall portfolio volatility by investing in complementary active managers with varying risk characteristics. Fund selection and allocations within the portfolio are implemented by Mercer's investment management team. The strategy is benchmarked to the Russell 1000 Growth Index.

(c) This category invests primarily in U.S. large cap companies that appear to be undervalued relative to their intrinsic value. It targets broad diversification across economic sectors and seeks to achieve lower overall portfolio volatility by investing in complementary active managers with varying risk characteristics. Fund selection and allocations within the portfolio are implemented by Mercer's investment management team. The strategy is benchmarked to the Russell 1000 Value Index.

(d) This category invests in small to mid-sized U.S. companies with above average earnings growth and revenue expectations. It targets broad diversification across economic sectors and seeks to achieve lower overall portfolio volatility by investing in complementary active managers with varying risk characteristics. Fund selection and allocations within the portfolio are implemented by Mercer's investment management team. The smaller cap orientation of the strategy requires the

investment team to be cognizant of liquidity and capital constraints, which are monitored on an ongoing basis. The strategy is benchmarked to the Russell 2500 Growth Index.

(e) This category invests in small to mid-sized U.S. companies that appear to be undervalued relative to their intrinsic value. It targets broad diversification across economic sectors and seeks to achieve lower overall portfolio volatility by investing in complementary active managers with varying risk characteristics. Fund selection and allocations within the portfolio are implemented by Mercer's investment management team. The smaller cap orientation of the strategy requires the investment team to be cognizant of liquidity and capital constraints, which are monitored on an ongoing basis. The strategy is benchmarked to the Russell 2500 Value Index.

(f) This category invests primarily in U.S. dollar-denominated investment grade and government securities. It may also invest opportunistically in out-of-benchmark positions including U.S. high yield, non-U.S. bonds, and Treasury Inflation-Protected Securities (TIPs). The strategy seeks to achieve lower overall portfolio volatility by investing in complementary active managers with varying risk characteristics, and total portfolio duration is targeted to be within 20% of the benchmark's duration. Total exposure to high yield issues is typically less than 10%, inclusive of direct investment in high yield and exposure through other core fixed income funds. Fund selection and allocations within the portfolio are implemented by Mercer's investment management team. The strategy is benchmarked to the Barclays Capital Aggregate Index.

(g) This category invests in all cap companies primarily operating in developed non-US markets, with some exposure to emerging markets. The strategy targets broad diversification across economic sectors and seeks to achieve lower overall portfolio volatility by investing in complementary active managers with varying risk characteristics. Total exposure to emerging markets is typically 10-15%, inclusive of direct investment in emerging markets and exposure through other non-U.S. equity funds. Fund selection and allocations within the portfolio are implemented by Mercer's investment management team. The strategy is benchmarked to the MSCI EAFE Index.

(h) This category invests in companies operating in non-US emerging markets. The strategy targets broad diversification across economic sectors and seeks to achieve lower overall portfolio volatility by investing in complementary active managers with varying risk characteristics. Fund selection and allocations within the portfolio are implemented by Mercer's investment management team. The strategy is benchmarked to the MSCI Emerging Markets Index.

(i) This category invests in companies operating in developed markets, globally. The strategy targets a diversified portfolio of equity securities issued by companies which the investment managers believe will exhibit less volatility in their price performance relative to the broad equity market as described by the MSCI World Index. The strategy is benchmarked to the MSCI World Index.

(j) This category invests in a passively managed U.S. long duration corporate investment grade portfolio at a 90% weight and a passively managed U.S. Long Treasury portfolio at a 10% weight. It seeks to provide broad exposure to U.S. long duration investment grade credit while allowing for short term liquidity through a strategic allocation to US Treasuries. The strategy is benchmarked 90% to the Barclays Capital U.S. Long Credit Index and 10% to the Barclays Capital Long Treasury.

(k) This category invests primarily in U.S. dollar denominated investment grade bonds and government securities with durations between 9 and 15 years. It may also invest opportunistically in out-of-benchmark positions including U.S. high yield, non-U.S. bonds, municipal bonds, and TIPs. The strategy seeks to achieve lower overall portfolio volatility by investing in complementary active managers with varying risk characteristics. Fund selection and allocations within the portfolio are implemented by Mercer's investment management team. The strategy is benchmarked to the Barclays Capital U.S. Long Government/Credit Index.

(l) This category invests in common stock of U.S. large cap companies. The strategy is benchmarked to the S&P 500 Index.

(m) This category invests primarily in U.S. dollar-denominated investment grade bonds and government securities. The strategy and its underlying passive investments are benchmarked to the Barclays Capital Aggregate Index.

(n) This category invests primarily in U.S. dollar-denominated investment grade bonds and government securities with durations between 9 and 15 years. The strategy and its underlying passive investments are benchmarked to the Barclays Capital Long Government/Credit Index.

(o) This category seeks to reduce the volatility of the plan's funded status and extend the duration of the assets by investing in a series of ultra long duration portfolios with target durations of up to 35 years. Each underlying portfolio is managed by a sub-advisor and consists of five interest rate swaps with sequential target or maturity dates, with the longest dated portfolio maturing in 2045. The interest rate swaps are fully collateralized, resulting in no leverage. The cash collateral is invested by the sub-advisor in an actively managed cash strategy that seeks to provide a return in excess of 3 month LIBOR. The ultra long duration strategy is used in conjunction with liability driven investing solutions, which seek to align the duration of the assets to the plan's liabilities. The Strategy is benchmarked to a Custom Liability Benchmark Portfolio.

(p) This category invests in a U.S. long duration corporate investment grade portfolio at a 90% weight and a U.S. long treasury portfolio at a 10% weight. It seeks to provide broad exposure to U.S. long duration investment grade corporate bonds with an emphasis on reducing default risk through active management while allowing for short term liquidity through a

strategic allocation to U.S. Treasuries. The strategy is benchmarked 90% to the Barclays Capital U.S. Long Corporate Index and 10% to the Barclay's Capital Long Treasury.

(q) This category invests primarily in long dated U.S. Treasury STRIPS often with maturities greater than 20 years. The strategy and its underlying passive investments are benchmarked to the Barclays Capital U.S. 20+ Year STRIPS Index.

(r) This category invests primarily in fixed income securities from issuers either located in developing/emerging markets or those rated below investment grade (high yield), globally. The strategy is benchmarked to a blended index of 50% JP Morgan Government Bond Index Emerging Markets Global Diversified and 50% Bank of America/Merrill Lynch Global High Yield Index.

There are no investments in CONSOL Energy stock held by these plans at December 31, 2015 or 2014.

There are no assets in the other postretirement benefit plans at December 31, 2015 or 2014.

Cash Flows:

If necessary, CONSOL Energy intends to contribute to the pension trust using prudent funding methods. However, the Company does not expect to contribute to the pension plan trust in 2016. Pension benefit payments are primarily funded from the trust. CONSOL Energy does not expect to contribute to the other postemployment plan in 2016 and intends to pay benefit claims as they are due.

The following benefit payments, reflecting expected future service, are expected to be paid:

	Pension Benefits	Other Postretirement Benefits
2016	$48,549	$40,863
2017	$48,053	$41,824
2018	$48,388	$42,048
2019	$48,413	$42,151
2020	$49,282	$42,373
Year 2021-2025	$238,468	$208,777

NOTE 17—COAL WORKERS' PNEUMOCONIOSIS (CWP) AND WORKERS' COMPENSATION:

CONSOL Energy is responsible under the Federal Coal Mine Health and Safety Act of 1969, as amended, for medical and disability benefits to employees and their dependents resulting from occurrences of coal workers' pneumoconiosis disease. CONSOL Energy is also responsible under various state statutes for pneumoconiosis benefits. CONSOL Energy primarily provides for these claims through a self-insurance program. The calculation of the actuarial present value of the estimated pneumoconiosis obligation is based on an annual actuarial study by independent actuaries and uses assumptions regarding disability incidence, medical costs, indemnity levels, mortality, death benefits, dependents and interest rates which are derived from actual company experience and outside sources. Recent legislative changes have not been favorable for CWP. Although these changes have not had a significant impact on the liability, CONSOL has noticed an increase in claims. Actuarial gains or losses can result from differences in incident rates and severity of claims filed as compared to original assumptions.

CONSOL Energy must also compensate individuals who sustain employment-related physical injuries or some types of occupational diseases and, on some occasions, for costs of their rehabilitation. Workers' compensation laws will also compensate survivors of workers who suffer employment-related deaths. Workers' compensation laws are administered by state agencies, and each state has its own set of rules and regulations regarding compensation that is owed to an employee that is injured in the course of employment. CONSOL Energy primarily provides for these claims through a self-insurance program. CONSOL Energy recognizes an actuarial present value of the estimated workers' compensation obligation calculated by independent actuaries. The calculation is based on claims filed and an estimate of claims incurred but not yet reported as well as various assumptions, including discount rate, future

healthcare trend rate, benefit duration and recurrence of injuries. Actuarial losses associated with workers' compensation have resulted from discount rate changes and differences in claims experience and incident rates as compared to prior assumptions.

On December 5, 2013, CONSOL Energy completed the CCC Sale, in connection with which the obligations for certain participants of the CWP and Workers' Compensation plans were transferred to Murray Energy. These plan settlements reduced CONSOL Energy's CWP and Workers' Compensation liabilities by $49,652 and $105,308, respectively at December 31, 2013 and resulted in adjustments of $43,892 and $13,768 in Other Comprehensive Income, net of $26,337 and $8,262 in deferred taxes for

CWP and Workers' Compensation, respectively, at December 31, 2013. The settlements were included in the results of discontinued operations.

	CWP at December 31,		Workers' Compensation at December 31,	
	2015	2014	2015	2014
Change in benefit obligation:				
Benefit obligation at beginning of period	$126,098	$121,183	$89,741	$85,096
State administrative fees and insurance bond premiums	—	—	3,581	3,352
Service, legal and administrative cost	6,491	5,674	9,389	9,781
Interest cost	5,116	5,537	3,195	3,577
Actuarial (gain) loss	(5,089)	5,578	(4,089)	3,805
Benefits paid	(10,113)	(11,874)	(18,999)	(15,523)
Settlements	—	—	347	(347)
Benefit obligation at end of period	$122,503	$126,098	$83,165	$89,741
Current assets	$—	$—	$1,450	$1,327
Current liabilities	(9,471)	(9,157)	(14,803)	(15,121)
Noncurrent liabilities	(113,032)	(116,941)	(69,812)	(75,947)
Net obligation recognized	$(122,503)	$(126,098)	$(83,165)	$(89,741)
Amounts recognized in accumulated other comprehensive income consist of:				
Net actuarial gain	$(68,101)	$(68,588)	$(13,440)	$(9,382)
Net amount recognized (before tax effect)	$(68,101)	$(68,588)	$(13,440)	$(9,382)

The components of the net periodic cost (credit) are as follows:

	CWP For the Years Ended December 31,			Workers' Compensation For the Years Ended December 31,		
	2015	2014	2013	2015	2014	2013
Service cost	$6,491	$5,674	$8,168	$9,389	$9,781	$15,943
Interest cost	5,116	5,537	7,031	3,195	3,577	6,401
Amortization of prior service cost	—	—	—	—	—	—
Recognized net actuarial gain	(5,576)	(6,196)	(16,384)	(31)	(382)	(2,630)
State administrative fees and insurance bond premiums	—	—	—	3,581	3,352	5,324
Settlement gain	—	—	(119,881)	—	—	(121,838)
Net periodic cost (credit)	$6,031	$5,015	$(121,066)	$16,134	$16,328	$(96,800)

Including settlements and curtailments associated with the CCC Sale, expenses (income) attributable to discontinued operations included in the net periodic cost (credit) were $(120,496) and $(113,097) for CWP and Workers' Compensation, respectively, for the year ended December 31, 2013. No amounts were included in discontinued operations for the years ended December 31, 2015 and 2014.

Following are amounts included in accumulated other comprehensive income that are expected to be recognized in 2016 net periodic benefit costs:

	CWP Benefits	Workers' Compensation Benefits

Actuarial gain recognition	$(5,531)	$(404)

CONSOL Energy utilizes a corridor approach to amortize actuarial gains and losses that have been accumulated under the Workers' Compensation and CWP plans. Cumulative gains and losses that are in excess of 10% of the greater of either the estimated liability or the market-related value of plan assets are amortized over the expected average remaining future service of the current active membership of the Workers' Compensation and CWP plans.

Assumptions:

The weighted-average discount rates used to determine benefit obligations and net periodic cost (benefit) are as follows:

	CWP			Workers' Compensation		
	For the Years Ended December 31,			For the Years Ended December 31,		
	2015	2014	2013	2015	2014	2013
Benefit obligations	4.60 %	4.21 %	4.75 %	4.26 %	3.84 %	4.57 %
Net periodic cost (benefit)	4.21 %	4.75 %	4.03 %	3.84 %	4.57 %	3.95 %

Discount rates are determined using a Company-specific yield curve model (above-mean) developed with the assistance of an external actuary. The Company-specific yield curve models (above-mean) use a subset of the expanded bond universe to determine the Company-specific discount rate. Bonds used in the yield curve are rated AA by Moody's or Standard & Poor's as of the measurement date. The yield curve models parallel the plans' projected cash flows, and the underlying cash flows of the bonds included in the models exceed the cash flows needed to satisfy the Company's plans.

Assumed discount rates have a significant affect on the amounts reported for both CWP costs and Workers' Compensation costs. A one-quarter percentage point change in assumed discount rate would have the following effect on benefit costs:

	0.25 Percentage Point Increase	0.25 Percentage Point Decrease
CWP costs (decrease) increase	$(431)	$459
Workers' compensation costs (decrease) increase	$(122)	$127

Cash Flows:

CONSOL Energy does not intend to make contributions to the CWP or Workers' Compensation plans in 2016, but it intends to pay benefit claims as they become due.

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

		Workers' Compensation		
	CWP Benefits	Total Benefits	Actuarial Benefits	Other Benefits
2016	$9,471	$17,248	$13,353	$3,895
2017	$7,764	$17,151	$13,159	$3,992
2018	$7,147	$17,161	$13,069	$4,092
2019	$6,977	$17,246	$13,052	$4,194
2020	$6,958	$17,395	$13,096	$4,299
Year 2021-2025	$36,082	$90,295	$67,131	$23,164

NOTE 18—OTHER EMPLOYEE BENEFIT PLANS:

UMWA Benefit Trusts:

The Coal Industry Retiree Health Benefit Act of 1992 (the Coal Act) created two multi-employer benefit plans: (1) the United Mine Workers of America Combined Benefit Fund (the Combined Fund) into which the former UMWA Benefit Trusts were merged, and (2) the United Mine Workers of America 1992 Benefit Plan (1992 Benefit Plan). In

connection with the sale of CCC and certain subsidiaries, CONSOL Energy retained responsibility for the contributions to these two funds. CONSOL Energy accounts for required contributions to these multi-employer trusts as expense when incurred.

The Combined Fund provides medical and death benefits for all beneficiaries of the former UMWA Benefit Trusts who were actually receiving benefits as of July 20, 1992. The 1992 Benefit Plan provides medical and death benefits to orphan UMWA-represented members eligible for retirement on February 1, 1993, and for those who retired between July 20, 1992 and September 30, 1994. The Act provides for the assignment of beneficiaries to former employers and the allocation of unassigned beneficiaries (referred to as orphans) to companies using a formula set forth in the Act. The Act requires that responsibility for funding the benefits to be paid to beneficiaries be assigned to their former signatory employers or related companies. This cost is recognized when contributions are assessed. CONSOL Energy's total contributions under the Act were $9,239, $10,121, and $11,435 for the years ended December 31, 2015, 2014 and 2013, respectively. Based on available information at December 31, 2015, CONSOL Energy's obligation for the Act is estimated to be approximately $101,240.

Pursuant to the provisions of the Tax Relief and Healthcare Act of 2006 (The 2006 Act) and the 1992 Benefit Plan, CONSOL Energy is required to provide security in an amount based on the annual cost of providing health care benefits for all individuals receiving benefits from the 1992 Benefit Plan who are attributable to CONSOL Energy, plus all individuals receiving benefits from an individual employer plan maintained by CONSOL Energy who are entitled to receive such benefits. In accordance with the terms of the 2006 Act and the 1992 Benefit Plan, CONSOL Energy must secure its obligations by posting letters of credit, which were $21,473, $21,394, and $60,741 at December 31, 2015, 2014 and 2013, respectively. The 2015, 2014 and 2013 security amounts were based on the annual cost of providing health care benefits and included a reduction in the number of eligible employees. The 2014 security amount also reflects the further reduction in the number of eligible individuals receiving benefits from CONSOL Energy's individual employer plan as the result of the CCC Sale, in connection with which the Company's obligation for certain participants was transferred to Murray Energy.

Equity Incentive Plans:

CONSOL Energy has an equity incentive plan that provides grants of stock-based awards to key employees and to non-employee directors. See Note 19–Stock-Based Compensation for further discussion of CONSOL Energy's equity incentive plans.

Investment Plan:

CONSOL Energy has an investment plan available to most non-represented employees. Throughout the year ended December 31, 2015, the Company's matching contribution was 6% of eligible compensation contributed by eligible employees. In conjunction with the qualified pension plan changes, beginning January 1, 2015, the Company contributed an additional 3% of eligible compensation into the 401(k) plan accounts for employees hired or rehired on or after October 1, 2014 or who were under age 40 or had less than 10 years of service with the Company as of September 30, 2014. This additional contribution was eliminated as of January 1, 2016. The Company may also make discretionary contributions to the Plan ranging from 1% to 4% (1% to 6% beginning January 1, 2016 and forward) of eligible compensation for eligible employees (as defined by the Plan). There were no such discretionary contributions made by the Company for the years ended December 31, 2015, 2014 and 2013, respectively. Total payments and costs were $24,075, $21,606, and $23,748 for the years ended December 31, 2015, 2014 and 2013, respectively.

Long-Term Disability:

CONSOL Energy has a Long-Term Disability Plan available to all eligible full-time salaried employees. The benefits for this plan are based on a percentage of monthly earnings, offset by all other income benefits available to the disabled.

	For the Years Ended December 31,		
	2015	2014	2013
Benefit cost (credit)	$2,619	$2,213	$(687)
Discount rate assumption used to determine net periodic benefit costs	3.18%	3.53%	3.04%

Expenses attributable to discontinued operations included in the net periodic cost (credit) above were $2,073 for the year ended December 31, 2013.

Liabilities incurred under the Long-Term Disability Plan are included in Other Accrued Liabilities and Deferred Credits and Other Liabilities–Other in the Consolidated Balance Sheets and amounted to a combined total of $19,789 and $22,427 at December 31, 2015 and 2014, respectively. As a result of the CCC Sale, the obligations for certain participants of the Long-Term Disability Plan now belong to Murray Energy. This was accounted for as a plan settlement and resulted in an adjustment at December 31, 2013 of $1,338 in Other Comprehensive Income, which is net of $803 in deferred taxes. This also reduced CONSOL Energy's Long-Term Disability liability by $10,140 at December 31, 2013.

NOTE 19—STOCK-BASED COMPENSATION:

CONSOL Energy adopted the CONSOL Energy Inc. Equity Incentive Plan (the Equity Incentive Plan) on April 7, 1999. The Equity Incentive Plan provides for grants of stock-based awards to key employees and to non-employee directors. Amendments to the Equity Incentive Plan have been approved by the Board of Directors since the commencement of the plan. Most recently, in May 2012, the Board of Directors approved an 8,000,000 increase to the total number of shares available for issuance, which brought the total number of shares of common stock that can be covered by grants to 31,800,000. At December 31, 2015, 2,246,532 shares of common stock remain available for all awards. The Equity Incentive Plan provides that the aggregate number of shares available for issuance will be reduced by one share for each share issued in settlement of stock options and by 1.62 for each share issued in settlement of Performance Share Units (PSUs), Restricted Stock Units (RSUs), or CONSOL Stock Units (CSUs). No award of stock options may be exercised under the Equity Incentive Plan after the tenth anniversary of the effective date of the award.

For only those shares expected to vest, CONSOL Energy recognizes stock-based compensation costs on a straight-line basis over the requisite service period of the award, which is generally the vesting term. Awards granted in 2013 and 2014 vest immediately if granted to retiree-eligible employees who are aged 62 and older. Awards granted in 2013 and 2014 vest at the end of one year when granted to employees aged 55 to 62 and who have also completed ten years of service. Awards granted in 2013 and 2014 vest over a three-year term at 33% per year for all other employees. Awards granted in 2015 vest over a three-year term at 33% per year. If an employee leaves the Company, all unvested shares are forfeited. The vesting of all awards will accelerate in the event of death and disability and may accelerate upon a change in control of CONSOL Energy. See each specific award section for special vesting terms related to non-employee directors and other specific awards. The total stock-based compensation expense recognized during the years ended December 31, 2015, 2014 and 2013 was $24,506, $41,877 and $56,987, respectively. The related deferred tax benefit totaled $9,229, $15,243 and $21,769, for the years ended December 31, 2015, 2014 and 2013, respectively. As of December 31, 2015, CONSOL Energy has $26,109 of unrecognized compensation cost related to all nonvested stock-based compensation awards, which is expected to be recognized over a weighted-average period of 1.74 years. When stock options are exercised and restricted and performance stock unit awards become vested, the issuances are made from CONSOL Energy's common stock shares.

Stock Options:

CONSOL Energy did not grant stock option awards during the years ended December 31, 2015, 2014 or 2013. The last awards were granted during 2012. A summary of the status of stock options granted is presented below:

	Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (in thousands)
Balance at December 31, 2014	4,043,029	$41.24		
Granted	—	$—		
Exercised	(363,620)	$22.78		
Forfeited	(58,407)	$38.23		
Balance at December 31, 2015	3,621,002	$43.15	3.04	$—
Vested	3,621,002	$43.15	3.04	$—
Exercisable at December 31, 2015	3,621,002	$43.15	3.04	$—

At December 31, 2015, there are 3,599,109 stock options outstanding under the Equity Incentive Plan. No fully vested employee stock options which vested under terms ranging from six months to one year are outstanding.

Non-employee director stock options vest 33% per year, beginning one year after the grant date. There are 21,893 fully vested stock options outstanding under these grants.

The aggregate intrinsic value in the table above represents the total pretax intrinsic value (the difference between CONSOL Energy's closing stock price on the last trading day of the year ended December 31, 2015 and the option's

exercise price, multiplied by the number of in-the-money options) that would have been received by the option holders had all option holders exercised their

options on December 31, 2015. This amount varies based on the fair market value of CONSOL Energy's stock. The total intrinsic value of options exercised for the years ended December 31, 2015, 2014 and 2013 was $2,744, $14,545 and $6,820, respectively.

Cash received from option exercises for the years ended December 31, 2015, 2014 and 2013 was $8,281, $15,011 and $3,720, respectively. The tax impact from option exercises totaled $208, $2,629, and $2,929, for the years ended December 31, 2015, 2014 and 2013, respectively. This excess tax benefit is included in cash flows from financing activities in the Consolidated Statements of Cash Flows.

Restricted Stock Units:

Under the Equity Incentive Plan, CONSOL Energy grants certain employees and non-employee directors restricted stock unit awards, which entitle the holder to shares of common stock as the award vests. Non-employee director restricted stock units vest at the end of one year. In 2014, restricted stock units were granted that will vest over a five year period unless certain market conditions are met, in which the award will accelerate. Compensation expense is recognized over the vesting period of the units, described above. The total fair value of restricted stock units granted during the years ended December 31, 2015, 2014 and 2013 was $26,550, $31,360 and $20,687, respectively. The total fair value of restricted stock units vested during the years ended December 31, 2015, 2014 and 2013 was $20,793, $15,686 and $37,002, respectively. The following table represents the nonvested restricted stock units and their corresponding fair value (based upon the closing share price) at the date of grant:

	Number of Shares	Weighted Average Grant Date Fair Value
Nonvested at December 31, 2014	1,248,191	$36.76
Granted	910,188	$29.17
Vested	(570,773)	$36.43
Forfeited	(211,947)	$30.74
Nonvested at December 31, 2015	1,375,659	$32.80

Performance Share Units:

Under the Equity Incentive Plan, CONSOL Energy grants certain employees performance share unit awards, which entitle the holder to shares of common stock subject to the achievement of certain market and performance goals. Compensation expense is recognized over the performance measurement period of the units in accordance with the provisions of the Stock Compensation Topic of the FASB Accounting Standards Codification for awards with market and performance vesting conditions. At December 31, 2015, achievement of the market goal is not probable, but achievement of the performance goal is probable. The total fair value of performance share units granted during the years ended December 31, 2015, 2014 and 2013 was $18,771, $11,853 and $1,270, respectively. The total fair value of performance share units vested during the years ended December 31, 2015, 2014 and 2013 was $20,083, $18,759 and $10,899, respectively. The following table represents the nonvested performance share units and their corresponding fair value (based upon the closing share price) on the date of grant:

	Number of Shares	Weighted Average Grant Date Fair Value
Nonvested at December 31, 2014	480,607	$31.99
Granted	520,888	$36.04
Vested	(497,134)	$40.40
Forfeited	(12,868)	$30.09
Nonvested at December 31, 2015	491,493	$27.83

Performance Options:

Under the Equity Incentive Plan, CONSOL Energy granted certain employees performance options, which entitled the holder to shares of common stock subject to the achievement of certain performance goals. Compensation expense was recognized over the vesting period of the options, described above. The Black-Scholes option valuation model was used to value each tranche separately. The total fair value of performance options vested during the years ended December 31, 2014 and 2013 was $4,949 and $1,650, respectively. A summary of the status of performance options granted is presented below:

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	Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (in thousands)
Balance at December 31, 2014	802,804	$45.05		
Granted	—	$—		
Exercised	—	$—		
Forfeited	—	$—		
Balance at December 31, 2015	802,804	$45.05	4.42	$—
Vested	802,804	$45.05	4.42	$—
Exercisable at December 31, 2015	802,804	$45.05	4.42	$—

CONSOL Stock Units:

Under the Equity Incentive Plan, CONSOL Energy granted certain employees CONSOL Stock Unit Awards, which entitled the holder to shares of common stock subject to the achievement of certain market and performance goals. Compensation expense was recognized over the performance measurement period of the units in accordance with the provisions of the Stock Compensation Topic of the FASB Accounting Standards Codification for awards with market and performance vesting conditions. CONSOL Energy used the Monte Carlo methodology to estimate the fair value of the CONSOL Stock Units. At December 31, 2015, the achievement of the market and performance goals is not probable. The total fair value of CONSOL Stock Units granted during the years ended December 31, 2015, 2014 and 2013 was $110, $189 and $28,381 respectively. The following table represents the nonvested CONSOL Stock Unit awards and their corresponding fair value (based upon the closing share price) at the date of grant:

	Number of Shares	Weighted Average Grant Date Fair Value
Nonvested at December 31, 2014	819,552	$33.74
Granted	4,616	$23.83
Forfeited	(20,170)	$33.72
Nonvested at December 31, 2015	803,998	$33.68

NOTE 20—SUPPLEMENTAL CASH FLOW INFORMATION:

The following are non-cash transactions that impact the investing and financing activities of CONSOL Energy. For non-cash transactions that relate to acquisitions and dispositions, see Note 2 - Discontinued Operations and Note - 3 Acquisitions and Dispositions.

CONSOL Energy obtains capital lease arrangements for company-used vehicles. For the years ended December 31, 2015, 2014 and 2013, CONSOL Energy entered into non-cash capital lease arrangements of $5,208, $1,572 and $4,178, respectively.

As of December 31, 2015, 2014 and 2013, CONSOL Energy purchased goods and services related to capital projects in the amount of $30,761, $74,292 and $40,870, respectively, which are included in accounts payable.

The following table shows cash paid (received) during the year for:

	For the Years Ended December 31,		
	2015	2014	2013
Interest (net of amounts capitalized)	$207,094	$233,631	$209,580
Income taxes	$(59,584)	$(81,962)	$35,079

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NOTE 21—CONCENTRATION OF CREDIT RISK AND MAJOR CUSTOMERS:

CONSOL Energy markets natural gas primarily to gas wholesalers, thermal coal principally to electric utilities in the United States, Canada and Western Europe and metallurgical coal to steel and coke producers worldwide.

Concentration of credit risk is summarized below:

	December 31,	
	2015	2014
Gas wholesalers	$72,664	$117,912
Thermal coal utilities	67,185	85,527
Coal brokers and distributors	48,972	41,983
Steel and coke producers	5,721	10,043
Various other	5,966	5,478
Total Accounts Receivable Trade	$200,508	$260,943

Accounts receivable from thermal coal utilities and steel and coke producers included amounts sold under the accounts receivable securitization facility at December 31, 2014. This facility was terminated on July 7, 2015. See Note 10–Accounts Receivable Securitization for further discussion.

During the year ended December 31, 2015, coal sales to Xcoal Energy Resources were $356,151 and coal sales to Duke Energy were $352,192, each of which comprised over 10% of the Company's revenues.

During the year ended December 31, 2014, coal sales to Duke Energy were $394,849 and coal sales to Xcoal Energy Resources were $344,617, each of which comprised over 10% of the Company's revenues.

During the year ended December 31, 2013, coal sales to Xcoal Energy Resources were $495,242 and coal sales to Duke Energy were $346,424, each of which comprised over 10% of the Company's revenues.

NOTE 22—FAIR VALUE OF FINANCIAL INSTRUMENTS:

CONSOL Energy determines the fair value of assets and liabilities based on the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants. The fair values are based on assumptions that market participants would use when pricing an asset or liability, including assumptions about risk and the risks inherent in valuation techniques and the inputs to valuations. The fair value hierarchy is based on whether the inputs to valuation techniques are observable or unobservable. Observable inputs reflect market data obtained from independent sources (including NYMEX forward curves, LIBOR-based discount rates and basis forward curves), while unobservable inputs reflect the Company's own assumptions of what market participants would use.

The fair value hierarchy includes three levels of inputs that may be used to measure fair value as described below.

Level One - Quoted prices for identical instruments in active markets.

Level Two - The fair value of the assets and liabilities included in Level 2 are based on standard industry income approach models that use significant observable inputs, including NYMEX forward curves, LIBOR-based discount rates and basis forward curves.

Level Three - Unobservable inputs significant to the fair value measurement supported by little or no market activity. The significant unobservable inputs used in the fair value measurement of the Company's third party guarantees are the credit risk of the third party and the third party surety bond markets. A significant increase or decrease in these values, in isolation, would have a directionally similar effect resulting in higher or lower fair value measurement of the Company's Level 3 guarantees.

In those cases when the inputs used to measure fair value meet the definition of more than one level of the fair value hierarchy, the lowest level input that is significant to the fair value measurement in its totality determines the applicable level in the fair value hierarchy.

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The financial instruments measured at fair value on a recurring basis are summarized below:

	Fair Value Measurements at December 31, 2015			Fair Value Measurements at December 31, 2014		
Description	Level 1	Level 2	Level 3	Level 1	Level 2	Level 3
Gas Derivatives	$—	$266,558	$—	$—	$193,069	$—
Murray Energy Guarantees	$—	$—	$1,228	$—	$—	$1,275

The following methods and assumptions were used to estimate the fair value for which the fair value option was not elected:

Cash and cash equivalents: The carrying amount reported in the balance sheets for cash and cash equivalents approximates its fair value due to the short-term maturity of these instruments.

Short-term notes payable: The carrying amount reported in the Consolidated Balance Sheets for short-term notes payable approximates its fair value due to the short-term maturity of these instruments.

Long-term debt: The fair value of long-term debt is measured using unadjusted quoted market prices or estimated using discounted cash flow analyses. The discounted cash flow analyses are based on current market rates for instruments with similar cash flows.

The carrying amounts and fair values of financial instruments for which the fair value option was not elected are as follows:

	December 31, 2015		December 31, 2014	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and Cash Equivalents	$72,578	$72,578	$176,989	$176,989
Short-Term Notes Payable	$952,000	$952,000	$—	$—
Long-Term Debt	$2,744,731	$1,848,040	$3,241,474	$3,169,154

Cash and cash equivalents represent highly-liquid instruments and constitute Level 1 fair value measurements. Certain of the Company’s debt is actively traded on a public market and, as a result, constitute Level 1 fair value measurements. The portion of the Company’s debt obligations that are not actively traded are valued through reference to the applicable underlying benchmark rate and, as a result, constitute Level 2 fair value measurements.

NOTE 23—DERIVATIVE INSTRUMENTS:

CONSOL Energy enters into financial derivative instruments to manage its exposure to commodity price volatility. CONSOL Energy de-designated all of its cash flow hedges on December 31, 2014 and accounts for all existing and future gas commodity hedges on a mark-to-market basis with changes in fair value recorded in current period earnings. In connection with this change, CONSOL Energy froze the balances recorded in Accumulated Other Comprehensive Income at December 31, 2014 and will reclassify balances to earnings as the underlying physical transactions occur, unless it is no longer probable that the physical transaction will occur at which time the related gains deferred in Other Comprehensive Income (OCI) will be immediately recorded in earnings.

CONSOL Energy is exposed to credit risk in the event of non-performance by counterparties. The creditworthiness of counterparties is subject to continuing review. The Company has not experienced any issues of non-performance by derivative counterparties.

None of the Company's counterparty master agreements currently require CONSOL Energy to post collateral for any of its positions. However, as stated in the counterparty master agreements, if CONSOL Energy's obligations with one of its counterparties cease to be secured on the same basis as similar obligations with the other lenders under the credit

facility, CONSOL Energy would have to post collateral for instruments in a liabilities position in excess of defined thresholds. All of the Company's derivative instruments are subject to master netting arrangements with our counterparties. CONSOL Energy recognizes all financial derivative instruments as either assets or liabilities at fair value on the Consolidated Balance Sheets on a net basis by counterparty.

Each of CONSOL Energy's counterparty master agreements allows, in the event of default, the ability to elect early termination of outstanding contracts. If early termination is elected, CONSOL Energy and the applicable counterparty would net settle all open hedge positions.

CONSOL Energy’s commodity derivative instruments accounted for a total notional amount of production of 456.1 Bcf at December 31, 2015 and are forecasted to settle through 2018. At December 31, 2014, the commodity derivative instruments accounted for a total notional amount of production of 215.9 Bcf. At December 31, 2015, the basis only swaps were for notional amounts of 124.4 Bcf and are forecasted to settle through 2018. At December 31, 2014, the basis only swaps were for notional amounts of 10.6 Bcf.

The gross fair value of CONSOL Energy's derivative instruments at December 31, 2015 and December 31, 2014 were as follows:

Asset Derivative Instruments			Liability Derivative Instruments		
	December 31,			December 31,	
	2015	2014		2015	2014
Commodity Derivative Instruments					
Prepaid Expense	$234,409	$123,676	Other Liabilities	$5,137	$—
Other Assets	44,539	68,656	Other Accrued Liabilities	—	—
Total Asset:	$278,948	$192,332	Total Liability:	$5,137	$—
Basis Only Swaps					
Prepaid Expense	$5,429	$1,064	Other Liabilities	$1,569	$—
Other Assets	1,093	—	Other Accrued Liabilities	12,206	327
Total Asset:	$6,522	$1,064	Total Liability:	$13,775	$327

The effect of derivative instruments on our Consolidated Statements of Income was as follows:

	Year Ended December 31,		
	2015	2014	2013
Cash Received in Settlement of Commodity Derivative Instruments			
Natural Gas Swaps	$193,976	$19,025	$79,900
Natural Gas Basis Swaps	2,372	—	—
Total Cash Received in Settlement of Commodity Derivative Instruments	$196,348	$19,025	$79,900
Non-Cash Portion of Gain (Loss) on Commodity Derivative Instruments			
Natural Gas Swaps	$81,142	$—	$—
Natural Gas Basis Swaps	(7,653)	—	—
Reclassified from Accumulated OCI	123,105	—	—
Gain (Loss) Recognized for Ineffectiveness*	—	4,168	(4,645)
Total Non-Cash Portion of Gain (Loss) on Commodity Derivative Instruments	$196,594	$4,168	$(4,645)
Gain (Loss) on Commodity Derivative Instruments			
Natural Gas Swaps	$275,118	$19,025	$79,900
Natural Gas Basis Swaps	(5,281)	—	—
Reclassified from Accumulated OCI	123,105	—	—
Gain (Loss) Recognized for Ineffectiveness*	—	4,168	(4,645)
Total Gain (Loss) on Commodity Derivative Instruments	$392,942	$23,193	$75,255

* No amounts were excluded from effectiveness testing of cash flow hedges.

Changes in Accumulated OCI, net of tax, attributable to cash flow hedges that were de-designated December 31, 2014 were as follows:

	Year Ended December 31,		
	2015	2014	2013
Natural Gas Price Swaps and Options			
Beginning Balance – Accumulated OCI	$121,521	$42,493	$76,761
Gain recognized in Accumulated OCI	—	97,316	45,631
Gain Reclassified from Accumulated OCI (Net of tax: $45,054, $10,465, $53,990)	(78,051)	(18,288)	(79,899)
Ending Balance – Accumulated OCI	$43,470	$121,521	$42,493

CONSOL Energy expects to reclassify an additional $43,470, net of tax of $25,011, out of Accumulated Other Comprehensive Income during the year ending December 31, 2016.

NOTE 24—COMMITMENTS AND CONTINGENT LIABILITIES:

CONSOL Energy and its subsidiaries are subject to various lawsuits and claims with respect to such matters as personal injury, wrongful death, damage to property, exposure to hazardous substances, governmental regulations including environmental remediation, employment and contract disputes and other claims and actions arising out of the normal course of business. CONSOL Energy accrues the estimated loss for these lawsuits and claims when the loss is probable and can be estimated. The Company's current estimated accruals related to these pending claims, individually and in the aggregate, are immaterial to the financial position, results of operations or cash flows of CONSOL Energy. It is possible that the aggregate loss in the future with respect to these lawsuits and claims could ultimately be material to the financial position, results of operations or cash flows of CONSOL Energy; however, such amounts cannot be reasonably estimated. The amount claimed against CONSOL Energy is disclosed below when an amount is expressly stated in the lawsuit or claim, which is not often the case. The maximum aggregate amount claimed in those lawsuits and claims, regardless of probability, where a claim is expressly stated or can be estimated, exceeds the aggregate amounts accrued for all lawsuits and claims by approximately $661,860.

The following lawsuits and claims include those for which a loss is probable and an accrual has been recognized.

Hale Litigation: This class action lawsuit was filed on September 23, 2010 in the U.S. District Court in Abingdon, Virginia. The putative class consists of forced-pooled unleased gas owners whose ownership of the coalbed methane (CBM) gas was declared to be in conflict with rights of others. The lawsuit seeks a judicial declaration of ownership of the CBM and damages based on allegations CNX Gas Company failed to either pay royalties due to conflicting claimants or deemed lessors or paid them less than required because of the alleged practice of improper below market sales and/or taking alleged improper post-production deductions. On September 30, 2013, the District Judge entered an Order certifying the class, and CNX Gas Company appealed the Order to the U.S. Fourth Circuit Court of Appeals. On August 19, 2014, the Fourth Circuit agreed with CNX Gas Company, reversed the Order certifying the class and remanded the case to the trial court for further proceedings consistent with the decision. On April 23, 2015, Plaintiffs filed a Renewed Motion for Class Certification, and on June 23, 2015, CNX Gas Company filed its Opposition to same. The Court held a hearing on the Motion on September 18, 2015 and has not yet ruled. CONSOL Energy continues to believe this action cannot properly proceed as a class action in any form, believes the case has meritorious defenses, and intends to defend it vigorously. The Company has established an accrual to cover its estimated liability for this case. This accrual is immaterial to the overall financial position of CONSOL Energy and is included in Other Accrued Liabilities on the Consolidated Balance Sheets.

Addison Litigation: This class action lawsuit was filed on April 28, 2010 in the United States District Court in Abingdon, Virginia. The putative class consists of gas lessors whose gas ownership is in conflict. The lawsuit seeks a judicial declaration of ownership of the CBM and damages based on the allegations that CNX Gas Company failed to

either pay royalties due these conflicting claimant lessors or paid them less than required because of the alleged practice of improper below market sales and/or taking alleged improper post-production deductions. On September 30, 2013, the District Judge entered an Order certifying the class, and CNX Gas Company appealed the Order to the U.S. Court of Appeals for the Fourth Circuit. On August 19, 2014, the Fourth Circuit agreed with CNX Gas Company, reversed the Order certifying the class and remanded the case to the trial court for further proceedings consistent with the decision. On April 23, 2015, Plaintiffs filed a Renewed Motion for Class Certification, and on June 23, 2015, CNX Gas Company filed its Opposition to same. The Court held a hearing on the Motion on September 18, 2015 and has not yet ruled. CONSOL Energy continues to believe this action cannot properly proceed as a class action in any form, believes the case has meritorious defenses, and intends to defend it vigorously. The Company has established an accrual to cover its estimated liability for this case. This accrual is immaterial to the overall financial position of CONSOL Energy and is included in Other Accrued Liabilities on the Consolidated Balance Sheets.

Clean Water Act - Bailey Mine: The Company received from the U.S. EPA on April 8, 2011 a request for information relating to National Pollutant Discharge Element System (NPDES) Permit compliance at the Company's Bailey and Enlow Fork Mines. In response, Consol Pennsylvania Coal Company submitted water discharge monitoring and other data to the EPA. The investigation has focused primarily on exceedances at three discharge points: Pond 12, Pond 2 and Pond 13. In early 2013, the case was referred to the U.S. Department of Justice (DOJ), and the Pennsylvania Department of Environmental Protection (PA DEP) also became involved. On December 18, 2014, the DOJ provided the Company a proposed Consent Decree to resolve certain Clean Water Act and Clean Streams Law claims against CONSOL Energy, Inc. and Consol Pennsylvania Coal Company with respect to the Bailey Mine Complex. The parties continue to negotiate the terms of the proposed Consent Decree. The Company has established an accrual to cover its estimated liability in this matter. This accrual is immaterial to the overall financial position of CONSOL Energy and is included in Other Accrued Liabilities on the Consolidated Balance Sheets.

The following royalty and land rights lawsuits and claims include those for which a loss is reasonably possible, but not probable, and accordingly, an accrual may not have been recognized. These claims are influenced by many factors which prevent the estimation of a range of potential loss. These factors include, but are not limited to, generalized allegations of unspecified damages (such as improper deductions), discovery having not commenced or not having been completed, unavailability of expert reports on damages and non-monetary issues are being tried. For example, in instances where a gas lease termination is sought, damages would depend on speculation as to if and when the gas production would otherwise have occurred, how many wells would have been drilled on the lease premises, what their production would be, what the cost of production would be, and what the price of gas would be during the production period. An estimate is calculated, if applicable, when sufficient information becomes available.

Virginia Mine Void Litigation: The Company is currently defending three lawsuits naming Consolidation Coal Company (CCC), Island Creek Coal Company (ICCC), CNX Gas Company, and/or CONSOL Energy. The lawsuits were filed in the U.S. District Court for the Western District of Virginia. On October 26, 2015, the trial court granted summary judgment in favor of the defendants in two of the actions upon its finding that plaintiffs' claims are barred by the applicable statutes of limitation. Plaintiffs have appealed both cases to the U.S. Court of Appeals for the Fourth Circuit. The third case remains pending in the trial court. On January 26, 2016, six mine void lawsuits that have twice before been filed and voluntarily dismissed, were refiled for a third time in state court but have not been served. The Complaints seek damages and injunctive relief in connection with the transfer of water from mining activities at Buchanan Mine into void spaces in inactive ICCC mines adjacent to the Buchanan operations, voids ostensibly underlying plaintiffs’ properties. While some of the plaintiffs have an ownership interest in the coal, others have some interest in one or more of the fee, surface, oil/gas or other mineral estates. The suits allege the water storage precludes access to and has damaged coal, impeded coalbed methane gas production and was made without compensation to the property owners. Plaintiffs seek recovery in tort, contract and trespass assumpsit (quasi-contract). The suits each seek damages between $50,000 and in excess of $100,000 plus punitive damages. The Company intends to vigorously defend these suits.

Kennedy Litigation: The Company is a party to a case filed on March 26, 2008 captioned Earl Kennedy (and others) v. CNX Gas Company and CONSOL Energy in the Court of Common Pleas of Greene County, Pennsylvania. The lawsuit alleges that CNX Gas Company and CONSOL Energy trespassed and converted gas and other minerals allegedly belonging to the plaintiffs in connection with wells drilled by CNX Gas Company. The complaint, as amended, seeks injunctive relief, including removing CNX Gas Company from the property, and compensatory damages of $20,000. The suit also sought to overturn existing law as to the ownership of coalbed methane in Pennsylvania, but that claim was dismissed by the court. The suit further sought a determination that the Pittsburgh 8 coal seam does not include the “roof/rider” coal. The court held a bench trial on the “roof/rider” coal issue in November 2011 and ruled in favor of CNX Gas Company and CONSOL Energy. On March 3, 2014, the Company won summary judgment on Counts 1 through 10 of the Amended Complaint, each relating to the alleged trespass of horizontal CBM wells into strata other than the Pittsburgh 8 Seam. The last remaining Count, seeking to quiet title to approximately 40

acres of Pittsburgh Seam coal, was nonsuited by Plaintiffs, without prejudice, on March 26, 2014. Plaintiffs filed Notices of Appeal with the Pennsylvania Superior Court. On April 22, 2015, the Superior Court issued its decision, affirming each of the orders and judgments entered in favor of CONSOL Energy by the trial court. On May 21, 2015, Plaintiffs filed a Petition for Allowance of Appeal with the Pennsylvania Supreme Court, which denied the Petition on December 31, 2015. The litigation is now concluded.

Rowland Litigation: Rowland Land Company filed a complaint in May 2011 against CONSOL Energy, CNX Gas Company, Dominion Resources Inc., and EQT Production Company (EQT) in Raleigh County Circuit Court, West Virginia. Rowland is the lessor on a 33,000 acre oil and gas lease in southern West Virginia. EQT was the original lessee, but farmed out the development of the lease to Dominion Resources in exchange for an overriding royalty. Dominion Resources sold the indirect subsidiary that held the lease to a subsidiary of CONSOL Energy on April 30, 2010. Subsequent to that acquisition, the subsidiary that held the lease was merged into CNX Gas Company as part of an internal reorganization. Rowland alleges that (i) Dominion Resources' sale of the subsidiary to CONSOL Energy was a change in control that required its consent under the terms of the farmout agreement

and lease, and/or (ii) the subsequent merger of the subsidiary into CNX Gas Company was an assignment that required its consent under the lease. The parties have reached a settlement in principle of this matter, which will be dismissed with prejudice.

At December 31, 2015, CONSOL Energy has provided the following financial guarantees, unconditional purchase obligations and letters of credit to certain third parties, as described by major category in the following table. These amounts represent the maximum potential total of future payments that we could be required to make under these instruments. These amounts have not been reduced for potential recoveries under recourse or collateralization provisions. Generally, recoveries under reclamation bonds would be limited to the extent of the work performed at the time of the default. No amounts related to these financial guarantees and letters of credit are recorded as liabilities on the financial statements. CONSOL Energy management believes that these guarantees will expire without being funded, and therefore, the commitments will not have a material adverse effect on financial condition.

	Amount of Commitment Expiration Per Period				
	Total Amounts Committed	Less Than 1 Year	1-3 Years	3-5 Years	Beyond 5 Years
Letters of Credit:					
Employee-Related	$63,837	$55,524	$8,313	$—	$—
Environmental	3,059	—	3,059	—	—
Other	191,281	177,742	13,539	—	—
Total Letters of Credit	258,177	233,266	24,911	—	—
Surety Bonds:					
Employee-Related	115,353	114,053	1,300	—	—
Environmental	535,738	494,210	41,528	—	—
Other	21,906	20,865	1,041	—	—
Total Surety Bonds	672,997	629,128	43,869	—	—
Guarantees:					
Coal	33,400	33,400	—	—	—
Other	74,902	40,110	14,553	12,405	7,834
Total Guarantees	108,302	73,510	14,553	12,405	7,834
Total Commitments	$1,039,476	$935,904	$83,333	$12,405	$7,834

Included in the above table are commitments and guarantees entered into in conjunction with the sale of Consolidation Coal Company and certain of its subsidiaries, which contain all five of its longwall coal mines in West Virginia, and its river operations to a subsidiary of Murray Energy Corporation (Murray Energy). As part of the sales agreement, CONSOL Energy has guaranteed certain equipment lease obligations and coal sales agreements that were assumed by Murray Energy. In the event that Murray Energy would default on the obligations defined in the agreements, CONSOL Energy would be required to perform under the guarantees. If CONSOL Energy would be required to perform, the stock purchase agreement provides various recourse actions. At December 31, 2015 and December 31, 2014, the fair value of these guarantees was $1,228 and $1,275, respectively, and are included in Other Accrued Liabilities on the Consolidated Balance Sheets. The fair value of certain guarantees was determined using CONSOL Energy’s risk-adjusted interest rate. Significant increases or decreases in the risk-adjusted interest rates may result in a significantly higher or lower fair value measurement. Coal sales agreement guarantees were valued based on an evaluation of coal market pricing compared to contracted sales price and includes an adjustment for nonperformance risk. No other amounts related to financial guarantees and letters of credit are recorded as liabilities in the financial statements. Significant judgment is required in determining the fair value of these guarantees. The guarantees of the leases and sales agreements are classified within Level 3 of the fair value hierarchy.

CONSOL Energy regularly evaluates the likelihood of default for all guarantees based on an expected loss analysis and records the fair value, if any, of its guarantees as an obligation in the consolidated financial statements.

CONSOL Energy and CNX Gas Company enter into long-term unconditional purchase obligations to procure major equipment purchases, natural gas firm transportation, gas drilling services and other operating goods and services. These purchase obligations are not recorded on the Consolidated Balance Sheets. As of December 31, 2015, the purchase obligations for each of the next five years and beyond were as follows:

Obligations Due	Amount
Less than 1 year	$193,685
1 - 3 years	308,206
3 - 5 years	245,834
More than 5 years	664,833
Total Purchase Obligations	$1,412,558

NOTE 25—SEGMENT INFORMATION:

CONSOL Energy consists of two principal business divisions: Exploration and Production (E&P) and Coal. The principal activity of the E&P division, which includes four reportable segments, is to produce pipeline quality natural gas for sale primarily to natural gas wholesalers. The E&P division's reportable segments are Marcellus, Utica, Coalbed Methane, and Other Gas. The Other Gas segment is primarily related to shallow oil and gas production as well as Upper Devonian Shale, and includes the Company's purchased gas activities and general and administrative activities, as well as various other activities assigned to the E&P division but not allocated to each individual well type.

The principal activities of the Coal division, which includes three reportable segments, are mining, preparation and marketing of thermal coal, sold primarily to power generators, and metallurgical coal, sold to metal and coke producers. The Coal division's reportable segments are Pennsylvania (PA) Operations, Virginia (VA) Operations, and Other Coal. Each of these reportable segments includes a number of operating segments (individual mines). For the year ended December 31, 2015, the PA Operations aggregated segment includes the following mines: Bailey Mine, Enlow Fork Mine, and Harvey Mine and the corresponding preparation plant facilities. For the year ended December 31, 2015, the VA Operations aggregated segment includes the Buchanan Mine and the corresponding preparation plant facilities. For the year ended December 31, 2015, the Other Coal segment includes the Miller Creek Complex, coal terminal operations, the Company's purchased coal activities, idled mine activities and general and administrative activities, as well as various other activities assigned to the Coal division but not allocated to each individual mine.

CONSOL Energy’s All Other division includes expenses from various other 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).

In the preparation of the following information, intersegment sales have been recorded at amounts approximating market. Operating profit for each segment is based on sales less identifiable operating and non-operating expenses. Assets are reflected at the division level for E&P and are not allocated between each individual E&P segment. These assets are not allocated to each individual segment due to the diverse asset base controlled by CONSOL Energy, whereby each individual asset may service more than one segment within the division. An allocation of such asset base would not be meaningful or representative on a segment by segment basis.

Industry segment results for the year ended December 31, 2015 are:

	Marcellus Shale	Utica Shale	Coalbed Methane	Other Gas	Total Gas	PA Operations	VA Operations	Other Coal	Total Coal	All Oth
Sales—Outside	$372,589	$92,223	$200,645	$61,464	$726,921	$1,289,043	$247,546	$121,276	$1,657,865	$—
Gain on Commodity Derivative Instruments	98,398	6,430	67,281	220,833	392,942	—	—	—	—	—
Other Outside Sales	—	—	—	—	—	—	—	30,967	30,967	—
Sales—Purchased Gas	—	—	—	14,450	14,450	—	—	—	—	—
Sales—Production Royalty Interests	—	—	—	45,181	45,181	—	—	—	—	—
Freight—Outside	—	—	—	—	—	15,236	1,584	8,777	25,597	—
Intersegment Transfers	—	—	1,538	—	1,538	—	—	—	—	—
Total Sales and Freight	$470,987	$98,653	$269,464	$341,928	$1,181,032	$1,304,279	$249,130	$161,020	$1,714,429	$—
Earnings (Loss) Before Income Taxes	$36,331	$(21,891)	$45,862	$(739,159)	$(678,857)	$407,269	$71,034	$22,102	$500,405	$(2
Segment Assets					$6,892,284	$2,076,301	$371,691	$1,299,625	$3,747,617	$20
Depreciation, Depletion and Amortization					$370,374	$176,863	$49,958	$52,388	$279,209	$18
Capital Expenditures					$832,446	$136,291	$33,396	$10,682	$180,369	$9,

(A) Included in the Coal segment are sales of $356,151 to Xcoal Energy Resources and sales of $352,192 to Duke Energy, each comprising over 10% of sales.
(B) Includes equity in earnings of unconsolidated affiliates of $46,614 and $8,283 for E&P and Coal, respectively.
(C) Includes investments in unconsolidated equity affiliates of $234,803 and $2,527 for E&P and Coal, respectively.

Industry segment results for the year ended December 31, 2014 are:

	Marcellus Shale	Utica Shale	Coalbed Methane	Other Gas	Total Gas	PA Operations	VA Operations	Other Coal	Total Coal	All Other
Sales—Outside	$458,272	$86,948	$340,739	$118,965	$1,004,924	$1,616,989	$297,088	$138,089	$2,052,166	$—
Gain on Commodity Derivative Instruments	14,869	1,247	4,103	2,974	23,193	—	—	—	—	—
Other Outside Sales	—	—	—	—	—	—	—	41,255	41,255	234,98
Sales—Purchased Gas	—	—	—	8,999	8,999	—	—	—	—	—
Sales—Production Royalty Interests	—	—	—	82,428	82,428	—	—	—	—	—
Freight—Outside	—	—	—	—	—	16,767	616	10,765	28,148	—
Intersegment Transfers	—	—	2,458	—	2,458	—	—	—	—	78,229
Total Sales and Freight	$473,141	$88,195	$347,300	$213,366	$1,122,002	$1,633,756	$297,704	$190,109	$2,121,569	$313,2
Earnings (Loss) Before Income Taxes	$151,617	$41,064	$91,672	$(94,639)	$189,714	$430,968	$11,507	$(33,090)	$409,385	$(32,8
Segment Assets					$7,364,185	$2,094,041	$323,299	$1,644,468	$4,061,808	$61,04
Depreciation, Depletion and Amortization					$323,600	$173,355	$48,289	$58,506	$280,150	$1,896
Capital Expenditures					$1,103,656	$340,305	$26,700	$13,171	$380,176	$9,593

(D) Included in the Coal segment are sales of $394,849 to Duke Energy and sales of $344,617 to Xcoal Energy Resources, each comprising over 10% of sales.

(E) Includes equity in earnings of unconsolidated affiliates of $32,217, $19,324 and $(1,750) for E&P, Coal, and All Other, respectively.

(F) Includes investments in unconsolidated equity affiliates of $121,721 and $31,237 for E&P and Coal, respectively.

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Industry segment results for the year ended December 31, 2013 are:

	Marcellus Shale	Utica Shale	Coalbed Methane	Other Gas	Total Gas	PA Operations	VA Operations	Other Coal	Total Coal	All Oth
Sales—Outside	$234,450	$4,370	$302,392	$121,234	$662,446	$1,357,337	$450,033	$210,697	$2,018,067	$—
Gain on Commodity Derivative Instruments	17,396	—	33,338	24,521	75,255	—	—	—	—	—
Other Outside Sales	—	—	—	—	—	—	—	43,364	43,364	216
Sales—Purchased Gas	—	—	—	6,531	6,531	—	—	—	—	—
Sales—Production Royalty Interests	—	—	—	63,202	63,202	—	—	—	—	—
Freight—Outside	—	—	—	—	—	17,779	4,010	13,649	35,438	—
Intersegment Transfers	—	—	3,168	—	3,168	—	—	—	—	127
Total Sales and Freight	$251,846	$4,370	$338,898	$215,488	$810,602	$1,375,116	$454,043	$267,710	$2,096,869	$34
Earnings (Loss) Before Income Taxes	$79,462	$(3,980)	$81,260	$(158,356)	$(1,614)	$310,467	$89,470	$(55,544)	$344,393	$(1
Segment Assets					$6,334,459	$1,963,801	$345,109	$1,992,255	$4,301,165	$17
Depreciation, Depletion and Amortization					$240,867	$129,230	$52,282	$75,135	$256,647	$2,(
Capital Expenditures					$968,607	$410,910	$21,431	$50,248	$482,589	$44

(G) Included in the Coal segment are sales of $495,242 to Xcoal Energy Resources and sales of $346,424 to Duke Energy, each comprising over 10% of sales.

(H) Includes equity in earnings of unconsolidated affiliates of $14,684 and $18,449 for E&P and Coal, respectively.

(I) Includes investments in unconsolidated equity affiliates of $206,060, $83,865, and $1,750 for E&P, Coal, and All Other, respectively.

Reconciliation of Segment Information to Consolidated Amounts:

Revenue and Other Income:

	For the Years Ended December 31,		
	2015	2014	2013
Total Segment Sales and Freight from External Customers	$2,500,981	$3,452,907	$3,045,467
Gain on Commodity Derivative Instruments	392,942	23,193	75,255
Other Income not Allocated to Segments (Note 4)	145,968	207,103	111,483
Gain on Sale of Assets	74,510	43,601	67,480
Total Consolidated Revenue and Other Income	$3,114,401	$3,726,804	$3,299,685

(Loss) Earnings Before Income Taxes:

	For the Years Ended December 31,		
	2015	2014	2013
Segment (Loss) Earnings Before Income Taxes for Total Reportable Business Segments	$(178,452)	$599,099	$342,779
Segment Loss Before Income Taxes for All Other Businesses	(29,223)	(32,821)	(17,201)
Interest (Expense), net (J)	(199,269)	(223,564)	(219,198)
Evaluation Fees for Non-Core Asset Dispositions (J)	—	(9,785)	(15,168)
Loss on Debt Extinguishment	(67,751)	(95,267)	—
Other Non-Operating Activity (J)	(24,205)	(54,538)	(45,137)
Earnings Before Income Taxes	$(498,900)	$183,124	$46,075

Total Assets:

	December 31,	
	2015	2014
Segment Assets for Total Reportable Business Segments	$10,639,901	$11,425,993
Segment Assets for All Other Businesses	203,611	61,042
Items Excluded from Segment Assets:		
Cash and Other Investments (J)	72,503	147,210
Recoverable Income Taxes	13,887	20,401
Total Consolidated Assets	$10,929,902	$11,654,646

(J) Excludes amounts specifically related to the gas segment.

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Enterprise-Wide Disclosures:

CONSOL Energy's Revenues by geographical location (K):

	For the Years Ended December 31,		
	2015	2014	2013
United States	$2,395,882	$3,331,388	$2,924,419
Europe	67,685	91,340	83,878
South America	20,959	21,685	29,787
Canada	5,836	8,494	3,575
Other	10,619	—	3,808
Total Revenues and Freight from External Customers (L)	$2,500,981	$3,452,907	$3,045,467

(K) CONSOL Energy attributes revenue to individual countries based on the location of the customer.
(L) CONSOL Energy has contractual relationships with certain U.S. based customers who distribute coal to international markets. The table above reflects the ultimate destination of CONSOL Energy coal.

CONSOL Energy's Property, Plant and Equipment by geographical location:

	December 31,	
	2015	2014
United States	$9,658,353	$10,151,448
Canada	11,024	11,024
Total Property, Plant and Equipment, net	$9,669,377	$10,162,472

NOTE 26—GUARANTOR SUBSIDIARIES FINANCIAL INFORMATION:
The payment obligations under the $74,470, 8.250% per annum senior notes due April 1, 2020, the $20,611, 6.375% per annum senior notes due March 1, 2021, the $1,855,617, 5.875% per annum senior notes due April 15, 2022, and the $493,439, 8.000% per annum senior notes due April 1, 2023 issued by CONSOL Energy are jointly and severally, and also fully and unconditionally, guaranteed by certain subsidiaries of CONSOL Energy. In accordance with positions established by the Securities and Exchange Commission (SEC), the following financial information sets forth separate financial information with respect to the parent, CNX Gas, a guarantor subsidiary, CNX Coal Resources LP (CNXC), a non-guarantor subsidiary, and the remaining guarantor and non-guarantor subsidiaries. The principal elimination entries include investments in subsidiaries and certain intercompany balances and transactions. CONSOL Energy, the parent, and a guarantor subsidiary manage several assets and liabilities of all other wholly owned subsidiaries. These include, for example, deferred tax assets, cash and other post-employment liabilities. These assets and liabilities are reflected as parent company or guarantor company amounts for purposes of this presentation.

Income Statement for the Year Ended December 31, 2015:

	Parent Issuer	CNX Gas Guarantor	Other Subsidiary Guarantors	CNXC Non-Guarantor	Other Subsidiary Non-Guarantors	Elimination	Consolidated
Revenues and Other Income:							
Natural Gas, NGLs and Oil Sales	$—	$728,458	$—	$ —	$—	$ (1,537)	$726,921
Gain on Commodity Derivative Instruments	—	392,942	—	—	—	—	392,942
Coal Sales	—	—	1,400,056	257,809	—	—	1,657,865
Other Outside Sales	—	—	30,967	—	—	—	30,967
Production Royalty Interests and Purchased Gas Sales	—	59,631	—	—	—	—	59,631
Freight-Outside Coal	—	—	22,550	3,047	—	—	25,597
Miscellaneous Other Income	(172,008)	65,502	80,112	704	4,105	167,553	145,968
Gain (Loss) on Sale of Assets	—	12,540	61,921	49	—	—	74,510
Total Revenue and Other Income	(172,008)	1,259,073	1,595,606	261,609	4,105	166,016	3,114,401
Costs and Expenses:							
Exploration and Production Costs							
Lease Operating Expense	—	98,997	—	—	—	—	98,997
Transportation, Gathering and Compression	—	355,923	—	—	—	—	355,923
Production, Ad Valorem, and Other Fees	—	30,438	—	—	—	—	30,438
Direct Administrative and Selling	—	46,192	—	—	—	—	46,192
Depreciation, Depletion and Amortization	—	370,374	—	—	—	—	370,374
Exploration and Production Related Other Costs	—	10,119	—	—	9	(9)	10,119
Production Royalty Interests and Purchased Gas Costs	—	46,544	—	—	—	—	46,544
Other Corporate Expenses	—	90,583	—	—	—	—	90,583
Impairment of Exploration and Production Properties	—	828,905	—	—	—	—	828,905
General and Administrative	—	54,244	—	—	—	—	54,244
Total Exploration and Production Costs	—	1,932,319	—	—	9	(9)	1,932,319
Coal Costs							
Operating and Other Costs	7,099	—	717,222	140,415	—	(1,537)	863,199
	—	—	68,573	10,271	—	—	78,844

Royalties and Production Taxes							
Direct Administrative and Selling	—	—	28,391	5,085	—	—	33,476
Depreciation, Depletion and Amortization	602	—	243,298	35,309	—	—	279,209
Freight Expense	—	—	22,550	3,047	—	—	25,597
General and Administrative Costs	—	—	21,512	8,324	—	—	29,836
Other Corporate Expenses	—	—	39,687	—	—	—	39,687
Total Coal Costs	7,701	—	1,141,233	202,451	—	(1,537)	1,349,848
Other Costs							
Miscellaneous Operating Expense	62,673	—	915	—	508	—	64,096
Depreciation, Depletion and Amortization	2	—	16	—	—	—	18
Loss on Debt Extinguishment	67,751	—	—	—	—	—	67,751
Interest Expense	186,291	5,613	6,389	8,495	76	(7,595)	199,269
Total Other Costs	316,717	5,613	7,320	8,495	584	(7,595)	331,134
Total Costs And Expenses	324,418	1,937,932	1,148,553	210,946	593	(9,141)	3,613,301
(Loss) Earnings Before Income Tax	(496,426)	(678,859)	447,053	50,663	3,512	175,157	(498,900)
Income Tax (Benefit) Expense	(121,541)	(257,056)	242,843	—	1,329	—	(134,425)
Net Income (Loss)	(374,885)	(421,803)	204,210	50,663	2,183	175,157	(364,475)
Less: Net Income Attributable to Noncontrolling Interest	—	—	—	—	—	10,410	10,410
Net Income (Loss) Attributable to CONSOL Energy Shareholders	$(374,885)	$(421,803)	$204,210	$ 50,663	$2,183	$ 164,747	$(374,885)

Balance Sheet at December 31, 2015:

	Parent Issuer	CNX Gas Guarantor	Other Subsidiary Guarantors	CNXC Non-Guarantor	Other Subsidiary Non-Guarantors	Elimination	Consolidated
Assets:							
Current Assets:							
Cash and Cash Equivalents	$64,999	$75	$—	$6,531	$973	$—	$72,578
Accounts and Notes Receivable:							
Trade	—	72,664	112,326	15,518	—	—	200,508
Other Receivables	18,933	99,001	3,784	377	—	—	122,095
Inventories	—	13,815	73,832	9,791	—	—	97,438
Recoverable Income Taxes	72,913	(59,026)	—	—	—	—	13,887
Prepaid Expenses	27,245	244,680	22,252	4,080	—	—	298,257
Total Current Assets	184,090	371,209	212,194	36,297	973	—	804,763
Property, Plant and Equipment:							
Property, Plant and Equipment	156,475	8,875,027	5,850,962	692,482	—	—	15,574,946
Less-Accumulated Depreciation, Depletion and Amortization	111,442	2,695,674	2,777,724	320,729	—	—	5,905,569
Total Property, Plant and Equipment-Net	45,033	6,179,353	3,073,238	371,753	—	—	9,669,377
Other Assets:							
Investment in Affiliates	11,276,858	234,803	6,293	—	—	(11,280,624)	237,330
Other	53,529	47,892	102,932	14,079	—	—	218,432
Total Other Assets	11,330,387	282,695	109,225	14,079	—	(11,280,624)	455,762
Total Assets	$11,559,510	$6,833,257	$3,394,657	$422,129	$973	$(11,280,624)	$10,929,902
Liabilities and Equity:							
Current Liabilities:							
Accounts Payable	$74,555	$149,930	$19,069	$14,023	$—	$13,817	$271,394
Accounts Payable (Recoverable)-Related Parties	3,321,299	1,521,444	(4,622,929)	3,452	(209,449)	(13,817)	—
Current Portion of Long-Term Debt	(2,754)	6,798	2,557	49	—	—	6,650
Short-Term Notes Payable	952,000	—	—	—	—	—	952,000
Other Accrued Liabilities	63,668	102,753	254,543	29,929	—	—	450,893
Total Current Liabilities	4,408,768	1,780,925	(4,346,760)	47,453	(209,449)	—	1,680,937
Long-Term Debt:	2,423,276	33,141	110,742	181,046	—	—	2,748,205
Deferred Credits and Other Liabilities:							
Deferred Income Taxes	(122,547)	197,176	—	—	—	—	74,629

Postretirement Benefits Other Than Pensions	—	—	630,892	—	—	—	630,892
Pneumoconiosis Benefits	—	—	111,485	1,547	—	—	113,032
Mine Closing	—	—	292,558	6,722	—	—	299,280
Gas Well Closing	—	135,174	29,383	77	—	—	164,634
Workers' Compensation	—	—	67,469	2,343	—	—	69,812
Salary Retirement	91,596	—	—	—	—	—	91,596
Reclamation	—	—	34,150	—	—	—	34,150
Other	56,390	105,588	4,410	571	—	—	166,959
Total Deferred Credits and Other Liabilities	25,439	437,938	1,170,347	11,260	—	—	1,644,984
Total CONSOL Energy Inc. Stockholders' Equity	4,702,027	4,581,253	6,460,328	182,370	210,422	(11,434,373)	4,702,027
Noncontrolling Interest	—	—	—	—	—	153,749	153,749
Total Liabilities and Equity	$11,559,510	$6,833,257	$3,394,657	$ 422,129	$ 973	$(11,280,624)	$10,929,902

Condensed Statement of Cash Flows for the Year Ended December 31, 2015:

	Parent	CNX Gas Guarantor	Other Subsidiary Guarantors	CNXC Non-Guarantor	Other Subsidiary Non-Guarantors	Elimination	Consolidated
Net Cash (Used in) Provided by Operating Activities	$(153,931)	$624,788	$(279,950)	$ 60,795	$ (92)	$254,239	$505,849
Cash Flows from Investing Activities:							
Capital Expenditures	$(9,752)	$(832,446)	$(153,112)	$ (27,257)	$ —	$—	$(1,022,567)
Proceeds From Sales of Assets	142	10,298	100,075	56	—	—	110,571
(Investments in), net of Distributions from, Equity Affiliates	—	(79,756)	(4,465)	—	—	—	(84,221)
Net Cash (Used in) Provided by Investing Activities	$(9,610)	$(901,904)	$(57,502)	$ (27,201)	$ —	$—	$(996,217)
Cash Flows from Financing Activities:							
Proceeds from (Payments on) Short-Term Borrowings	$952,000	$252,900	$—	$ —	$ —	$(252,900)	$952,000
(Payments on) Proceeds from Miscellaneous Borrowings	(1,281)	(6,391)	3,374	(40)	—	—	(4,338)
Payments on Long-Term Borrowings	(1,263,719)	—	—	(8,761)	—	8,761	(1,263,719)
Proceeds from Revolver - MLP	—	—	200,000	185,000	—	(200,000)	185,000
Distributions of Noncontrolling Interest	—	—	—	(11,353)	—	6,293	(5,060)
Proceeds from Sale of MLP Interest	—	—	148,359	148,359	—	(148,359)	148,359
Proceeds from Long-Term Borrowings	492,760	—	—	13,592	—	(13,592)	492,760
Net Distributions from Offering to Parent	—	—	—	(342,711)	—	342,711	—
Net Change in Parent Advancements	—	—	—	(6,823)	—	6,823	—
Tax Benefit from Stock-Based Compensation	208	—	—	—	—	—	208
Dividends Paid	(33,281)	—	—	—	—	—	(33,281)
Proceeds from Issuance of Common Stock	8,288	—	—	—	—	—	8,288
Treasury Stock Activity	(71,674)	—	—	—	—	—	(71,674)
	—	—	(14,281)	(4,329)	—	(3,976)	(22,586)

Debt Issuance and Financing Fees							
Net Cash Provided by (Used in) Financing Activities	$83,301	$246,509	$337,452	$ (27,066)	$ —	$(254,239)	$385,957

Statement of Comprehensive Income for the Year Ended December 31, 2015:

	Parent	CNX Gas Guarantor	Other Subsidiary Guarantors	CNXC Non-Guarantor	Other Subsidiary Non-Guarantors	Elimination	Consolidated
Net (Loss) Income	$(374,885)	$(421,803)	$204,210	$50,663	$2,183	$175,157	$ (364,475)
Other Comprehensive (Loss) Income:							
Actuarially Determined Long-Term Liability Adjustments	(86,447)	—	(84,974)	(1,473)	—	86,447	(86,447)
Reclassification of Cash Flow Hedge from OCI to Earnings	(78,051)	(78,051)	—	—	—	78,051	(78,051)
Other Comprehensive (Loss) Income:	(164,498)	(78,051)	(84,974)	(1,473)	—	164,498	(164,498)
Comprehensive (Loss) Income	(539,383)	(499,854)	119,236	49,190	2,183	339,655	(528,973)
Less: Comprehensive Income Attributable to Noncontrolling Interest	—	—	—	—	—	10,410	10,410
Comprehensive (Loss) Income Attributable to CONSOL Energy Inc. Shareholders	$(539,383)	$(499,854)	$119,236	$49,190	$2,183	$329,245	$ (539,383)

Income Statement for the Year Ended December 31, 2014:

	Parent Issuer	CNX Gas Guarantor	Other Subsidiary Guarantors	CNXC Non-Guarantor	Other Subsidiary Non-Guarantors	Elimination	Consolidated
Revenues and Other Income:							
Natural Gas, NGLs and Oil Sales	$—	$1,007,381	$—	$ —	$—	$(2,457)	$1,004,924
Gain on Commodity Derivative Instruments	—	23,193	—	—	—	—	23,193
Coal Sales	—	—	1,728,768	323,398	—	—	2,052,166
Other Outside Sales	—	—	41,255	—	234,987	—	276,242
Production Royalty Interests and Purchased Gas Sales	—	91,427	—	—	—	—	91,427
Freight-Outside Coal	—	—	24,795	3,353	—	—	28,148
Miscellaneous Other Income	420,176	67,308	170,164	7,580	9,668	(467,793)	207,103
Gain (Loss) on Sale of Assets	—	45,917	(2,485)	148	21	—	43,601
Total Revenue and Other Income	420,176	1,235,226	1,962,497	334,479	244,676	(470,250)	3,726,804
Costs and Expenses:							
Exploration and Production Costs							
Lease Operating Expense	—	109,172	—	—	—	—	109,172
Transportation, Gathering and Compression	—	258,110	—	—	—	—	258,110
Production, Ad Valorem, and Other Fees	—	39,418	—	—	—	—	39,418
Direct Administrative and Selling	—	55,004	—	—	—	—	55,004
Depreciation, Depletion and Amortization	—	323,600	—	—	—	—	323,600
Exploration and Production Related Other Costs	—	22,718	637	—	—	—	23,355
Production Royalty Interests and Purchased Gas Costs	—	77,197	—	—	—	(12)	77,185
Other Corporate Expenses	—	86,588	—	—	—	—	86,588
General and Administrative	—	64,047	—	—	—	—	64,047
Total Exploration and Production Costs	—	1,035,854	637	—	—	(12)	1,036,479
Coal Costs							
Operating and Other Costs	23,524	—	1,129,678	171,993	—	(2,458)	1,322,737
Royalties and Production Taxes	—	—	86,779	14,111	—	—	100,890
	—	—	37,662	6,444	—	—	44,106

Direct Administrative and Selling							
Depreciation, Depletion and Amortization	558	—	244,921	34,671	—	—	280,150
Freight Expense	—	—	24,795	3,353	—	—	28,148
General and Administrative Costs	—	—	32,098	13,062	—	—	45,160
Other Corporate Expenses	—	—	55,321	—	—	—	55,321
Total Coal Costs	24,082	—	1,611,254	243,634	—	(2,458)	1,876,512
Other Costs							
Miscellaneous Operating Expense	76,828	—	1,235	—	231,111	—	309,174
General and Administrative Costs	—	—	—	—	788	—	788
Depreciation, Depletion and Amortization	25	—	57	—	1,814	—	1,896
Loss on Debt Extinguishment	95,267	—	—	—	—	—	95,267
Interest Expense	213,384	9,021	41,798	6,946	235	(47,820)	223,564
Total Other Costs	385,504	9,021	43,090	6,946	233,948	(47,820)	630,689
Total Costs And Expenses	409,586	1,044,875	1,654,981	250,580	233,948	(50,290)	3,543,680
Earnings (Loss) Before Income Tax	10,590	190,351	307,516	83,899	10,728	(419,960)	183,124
Income Tax (Benefit) Expense	(152,500)	66,441	96,348	—	4,058	—	14,347
Income (Loss) From Continuing Operations	163,090	123,910	211,168	83,899	6,670	(419,960)	168,777
Loss From Discontinued Operations, net	—	—	—	—	(5,687)	—	(5,687)
Net Income (Loss) Attributable to CONSOL Energy Shareholders	$163,090	$123,910	$211,168	$ 83,899	$983	$(419,960)	$163,090

Balance Sheet at December 31, 2014:

	Parent Issuer	CNX Gas Guarantor	Other Subsidiary Guarantors	CNXC Non-Guarantor	Other Subsidiary Non-Guarantors	Elimination	Consolidated
Assets:							
Current Assets:							
Cash and Cash Equivalents	$145,236	$30,682	$—	$3	$1,068	$—	$176,989
Accounts and Notes Receivable:							
Trade	—	117,912	—	—	143,031	—	260,943
Other Receivables	25,256	309,247	29,052	384	12	(17,931)	346,020
Inventories	—	14,748	76,486	10,639	—	—	101,873
Recoverable Income Taxes	79,426	(59,025)	—	—	—	—	20,401
Prepaid Expenses	32,742	129,796	21,282	3,922	—	—	187,742
Total Current Assets	282,660	543,360	126,820	14,948	144,111	(17,931)	1,093,968
Property, Plant and Equipment:							
Property, Plant and Equipment	158,555	8,066,308	5,763,321	686,593	—	—	14,674,777
Less-Accumulated Depreciation, Depletion and Amortization	108,432	1,497,569	2,618,597	287,707	—	—	4,512,305
Total Property, Plant and Equipment-Net	50,123	6,568,739	3,144,724	398,886	—	—	10,162,472
Other Assets:							
Investment in Affiliates	12,571,886	121,721	27,544	—	—	(12,568,193)	152,958
Notes Receivable	—	—	160,831	—	—	(160,831)	—
Other	141,704	71,339	27,228	4,977	—	—	245,248
Total Other Assets	12,713,590	193,060	215,603	4,977	—	(12,729,024)	398,206
Total Assets	$13,046,373	$7,305,159	$3,487,147	$418,811	$144,111	$(12,746,955)	$11,654,646
Liabilities and Equity:							
Current Liabilities:							
Accounts Payable	$86,313	$385,381	$44,566	$15,713	$—	$—	$531,973
Accounts Payable (Recoverable)-Related Parties	4,498,933	182,758	(5,334,094)	—	(67,747)	720,150	—
Current Portion of Long-Term Debt	(3,193)	6,602	3,463	18,261	—	(17,931)	7,202
Short-Term Notes Payable	—	720,150	—	—	—	(720,150)	—
Other Accrued Liabilities	119,484	172,787	275,130	35,571	—	—	602,972
Total Current Liabilities	4,701,537	1,467,678	(5,010,935)	69,545	(67,747)	(17,931)	1,142,147
Long-Term Debt:	3,092,948	37,342	112,757	161,160	—	(160,831)	3,243,376

Deferred Credits and Other Liabilities:							
Deferred Income Taxes	(248,700)	507,724	—	—	—	—	259,024
Postretirement Benefits Other Than Pensions	—	—	698,401	5,279	—	—	703,680
Pneumoconiosis Benefits	—	—	115,691	1,250	—	—	116,941
Mine Closing	—	—	299,663	7,126	—	—	306,789
Gas Well Closing	—	116,930	57,604	835	—	—	175,369
Workers' Compensation	—	—	73,566	2,381	—	—	75,947
Salary Retirement	109,956	—	—	—	—	—	109,956
Reclamation	—	—	33,788	—	—	—	33,788
Other	61,174	94,378	2,010	609	—	—	158,171
Total Deferred Credits and Other Liabilities	(77,570)	719,032	1,280,723	17,480	—	—	1,939,665
Total CONSOL Energy Inc. Stockholders' Equity	5,329,458	5,081,107	7,104,602	170,626	211,858	(12,568,193)	5,329,458
Total Liabilities and Equity	$13,046,373	$7,305,159	$3,487,147	$418,811	$144,111	$(12,746,955)	$11,654,646

Condensed Statement of Cash Flows for the Year Ended December 31, 2014:

	Parent	CNX Gas Guarantor	Other Subsidiary Guarantors	CNXC Non-Guarantor	Other Subsidiary Non-Guarantors	Elimination	Consolidated
Net Cash (Used in) Provided by Continuing Operations	$(178,921)	$567,851	$43,102	$ 114,109	$ 36,902	$387,663	$970,706
Net Cash Used in Discontinued Operating Activities	—	—	—	—	(33,926)	—	(33,926)
Net Cash (Used in) Provided by Operating Activities	$(178,921)	$567,851	$43,102	$ 114,109	$ 2,976	$387,663	$936,780
Cash Flows from Investing Activities:							
Capital Expenditures	$(4,420)	$(1,103,656)	$(317,288)	$ (68,061)	$ —	$—	$(1,493,425)
Proceeds From Sales of Assets	44,049	92,507	205,030	15,237	13	—	356,836
(Investments in), net of Distributions from, Equity Affiliates	—	85,248	9,959	—	—	—	95,207
Net Cash Provided by (Used in) Investing Activities	$39,629	$(925,901)	$(102,299)	$ (52,824)	$ 13	$—	$(1,041,382)
Cash Flows from Financing Activities:							
(Payments on) Proceeds from Miscellaneous Borrowings	$(12,135)	$387,663	$(7,238)	$ (19)	$ (2,630)	$(387,663)	$(22,022)
Payments on Long-Term Borrowings	(1,819,005)	—	—	(1,849)	—	1,849	(1,819,005)
Proceeds from Long-Term Borrowings	1,859,920	—	—	11,371	—	(11,371)	1,859,920
Net Change in Parent Advancements	—	—	—	(70,788)	—	70,788	—
Tax Benefit from Stock-Based Compensation	2,629	—	—	—	—	—	2,629
Dividends Paid	(57,506)	—	—	—	—	—	(57,506)
Proceeds from Issuance of Common Stock	15,016	—	—	—	—	—	15,016
Debt Issuance and Financing Fees	(24,861)	—	—	—	—	—	(24,861)
Other Financing Activities	—	(5,169)	5,169	—	—	—	—
Net Cash (Used in) Provided by Financing	$(35,942)	$382,494	$(2,069)	$ (61,285)	$ (2,630)	$(326,397)	$(45,829)

Activities

Statement of Comprehensive Income for the Year Ended December 31, 2014:

	Parent	CNX Gas Guarantor	Other Subsidiary Guarantors	CNXC Non-Guarantor	Other Subsidiary Non-Guarantors	Elimination	Consolidated
Net Income (Loss)	$163,090	$123,910	$211,168	$83,899	$983	$(419,960)	$ 163,090
Other Comprehensive Income (Loss):							
Actuarially Determined Long-Term Liability Adjustments	94,989	—	61,550	33,439	—	(94,989)	94,989
Net (Decrease) Increase in the Value of Cash Flow Hedge	97,316	97,316	—	—	—	(97,316)	97,316
Reclassification of Cash Flow Hedge from OCI to Earnings	(18,288)	(18,288)	—	—	—	18,288	(18,288)
Other Comprehensive Income (Loss):	174,017	79,028	61,550	33,439	—	(174,017)	174,017
Comprehensive Income (Loss) Attributable to CONSOL Energy Inc. Shareholders	$337,107	$202,938	$272,718	$117,338	$983	$(593,977)	$ 337,107

Income Statement for the Year Ended December 31, 2013:

	Parent Issuer	CNX Gas Guarantor	Other Subsidiary Guarantors	CNXC Non-Guarantor	Other Subsidiary Non-Guarantors	Elimination	Consolidated
Revenues and Other Income:							
Natural Gas, NGLs and Oil Sales	$—	$665,835	$—	$ —	$—	$(3,389)	$662,446
Gain on Commodity Derivative Instruments	—	75,255	—	—	—	—	75,255
Coal Sales	—	—	1,746,600	271,467	—	—	2,018,067
Other Outside Sales	—	—	43,364	—	216,419	—	259,783
Production Royalty Interests and Purchased Gas Sales	—	69,733	—	—	—	—	69,733
Freight-Outside Coal	—	—	31,882	3,556	—	—	35,438
Miscellaneous Other Income	886,280	36,372	60,804	1,336	18,332	(891,641)	111,483
Gain (Loss) on Sale of Assets	—	21,000	46,490	(124)	114	—	67,480
Total Revenue and Other Income	886,280	868,195	1,929,140	276,235	234,865	(895,030)	3,299,685
Costs and Expenses:							
Exploration and Production Costs							
Lease Operating Expense	—	87,543	—	—	—	—	87,543
Transportation, Gathering and Compression	—	201,024	—	—	—	—	201,024
Production, Ad Valorem, and Other Fees	—	28,676	—	—	—	—	28,676
Direct Administrative and Selling	—	49,092	—	—	—	—	49,092
Depreciation, Depletion and Amortization	—	240,867	—	—	—	—	240,867
Exploration and Production Related Other Costs	—	61,104	—	—	—	—	61,104
Production Royalty Interests and Purchased Gas Costs	—	57,906	—	—	—	(41)	57,865
Other Corporate Expenses	—	95,535	—	—	—	—	95,535
General and Administrative	—	39,047	—	—	—	—	39,047
Total Exploration and Production Costs	—	860,794	—	—	—	(41)	860,753
Coal Costs							
Operating and Other Costs	15,505	—	1,152,290	151,514	—	(3,725)	1,315,584
Royalties and Production Taxes	—	—	91,082	11,046	—	—	102,128
	—	—	43,536	5,687	—	—	49,223

Direct Administrative and Selling							
Depreciation, Depletion and Amortization	643	—	230,158	25,846	—	—	256,647
Freight Expense	—	—	31,882	3,556	—	—	35,438
General and Administrative Costs	—	—	27,846	12,201	—	—	40,047
Other Corporate Expenses	—	—	55,802	—	—	—	55,802
Total Coal Costs	16,148	—	1,632,596	209,850	—	(3,725)	1,854,869
Other Costs							
Miscellaneous Operating Expense	133,715	—	(34,226)	—	215,691	—	315,180
General and Administrative Costs	—	—	—	—	936	—	936
Depreciation, Depletion and Amortization	697	—	—	—	1,977	—	2,674
Interest Expense	211,449	8,605	43,367	2,093	47	(46,363)	219,198
Total Other Costs	345,861	8,605	9,141	2,093	218,651	(46,363)	537,988
Total Costs And Expenses	362,009	869,399	1,641,737	211,943	218,651	(50,129)	3,253,610
Earnings (Loss) Before Income Tax	524,271	(1,204)	287,403	64,292	16,214	(844,901)	46,075
Income Tax (Benefit) Expense	(136,171)	1,420	95,429	—	6,133	—	(33,189)
Income (Loss) From Continuing Operations	660,442	(2,624)	191,974	64,292	10,081	(844,901)	79,264
Income From Discontinued Operations, net	—	—	—	—	579,792	—	579,792
Net Income (Loss)	660,442	(2,624)	191,974	64,292	589,873	(844,901)	659,056
Less: Net Income Attributable to Noncontrolling Interest	—	(1,386)	—	—	—	—	(1,386)
Net Income (Loss) Attributable to CONSOL Energy Shareholders	$660,442	$(1,238)	$191,974	$ 64,292	$589,873	$(844,901)	$660,442

Condensed Statement of Cash Flows for the Year Ended December 31, 2013:

	Parent	CNX Gas Guarantor	Other Subsidiary Guarantors	CNXC Non-Guarantor	Other Subsidiary Non-Guarantors	Elimination	Consolidated
Net Cash Provided by (Used in) Continuing Operations	$51,093	$440,763	$478,267	$ 94,416	$ (843,456)	$332,487	$553,570
Net Cash Provided by Discontinued Operating Activities	—	—	—	—	105,206	—	105,206
Net Cash Provided by (Used in) Operating Activities	$51,093	$440,763	$478,267	$ 94,416	$ (738,250)	$332,487	$658,776
Cash Flows from Investing Activities:							
Capital Expenditures	$(68,796)	$(968,607)	$(376,471)	$ (82,182)	$ —	$—	$(1,496,056)
Change in Restricted Cash	—	—	68,673	—	—	—	68,673
Proceeds From Sales of Assets	327,964	350,975	(209,636)	14,554	112	—	483,969
(Investments in), net of Distributions from, Equity Affiliates	—	(47,500)	11,788	—	—	—	(35,712)
Net Cash Provided by (Used in) Continuing Operations	259,168	(665,132)	(505,646)	(67,628)	112	—	(979,126)
Net Cash Provided by Discontinued Investing Activities	—	—	—	—	777,145	—	777,145
Net Cash Provided by (Used in) Investing Activities	$259,168	$(665,132)	$(505,646)	$ (67,628)	$ 777,257	$—	$(201,981)
Cash Flows from Financing Activities:							
Proceeds from (Payments on) Short-Term Borrowings	$—	$332,487	$—	$ —	$ —	$(332,487)	$—
(Payments on) Proceeds from Miscellaneous Borrowings	(25,952)	—	(4,787)	(13)	(792)	—	(31,544)
Payments on Securitization Facility	—	—	—	—	(37,846)	—	(37,846)
Payments on Long-Term Borrowings	—	—	—	(9,591)	—	9,591	—
Proceeds from Long-Term Borrowings	—	—	—	18,893	—	(18,893)	—
Net Change in Parent Advancements	—	—	—	(36,078)	—	36,078	—

Dividends (Paid)	14,168	(100,000)	—	—	—	—	(85,832)
Proceeds from Issuance of Common Stock	3,727	—	—	—	—	—	3,727
Other Financing Activities	778	(5,232)	5,232	—	—	—	778
Net Cash (Used in) Provided by Continuing Operations	(7,279)	227,255	445	(26,789)	(38,638)	(305,711)	(150,717)
Net Cash Used in Discontinued Financing Activities	—	—	—	—	(520)	—	(520)
Net Cash (Used in) Provided by Financing Activities	$(7,279)	$227,255	$445	$ (26,789)	$ (39,158)	$(305,711)	$(151,237)

Statement of Comprehensive Income for the Year Ended December 31, 2013:

	Parent	CNX Gas Guarantor	Other Subsidiary Guarantors	CNXC Non-Guarantor	Other Subsidiary Non-Guarantors	Elimination	Consolidated
Net Income (Loss)	$660,442	$(2,624)	$191,974	$64,292	$589,873	$(844,901)	$659,056
Other Comprehensive Income (Loss):							
Actuarially Determined Long-Term Liability Adjustments	456,493	—	448,074	8,419	—	(456,493)	456,493
Net (Decrease) Increase in the Value of Cash Flow Hedge	45,631	45,631	—	—	—	(45,631)	45,631
Reclassification of Cash Flow Hedge from OCI to Earnings	(79,899)	(79,899)	—	—	—	79,899	(79,899)
Other Comprehensive Income (Loss):	422,225	(34,268)	448,074	8,419	—	(422,225)	422,225
Comprehensive Income (Loss)	1,082,667	(36,892)	640,048	72,711	589,873	(1,267,126)	1,081,281
Less: Comprehensive Income Attributable to Noncontrolling Interest	—	—	—	—	—	(1,386)	(1,386)
Comprehensive Income (Loss) Attributable to CONSOL Energy Inc. Shareholders	$1,082,667	$(36,892)	$640,048	$72,711	$589,873	$(1,265,740)	$1,082,667

NOTE 27—RELATED PARTY TRANSACTIONS

CONE Midstream Partners LP

On September 30, 2011, CNX Gas Company and Noble Energy, Inc., an unrelated third party and joint venture partner, formed CONE Gathering LLC (CONE) to develop and operate each company's gas gathering system needs in the Marcellus Shale play. CONSOL Energy accounts for CNX Gas Company's 50% ownership interest in CONE Gathering LLC under the equity method of accounting.

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, the Partnership received net proceeds of $412,741 from the offering, after deducting underwriting discounts and commissions, and structuring fees of $28,779 along with additional estimated offering expenses of approximately $1,230. Of the proceeds received, $203,986 was distributed to both CNX Gas Company LLC ("CNX Gas Company") and Noble Energy on September 30, 2014.

During the year ended December 31, 2015, there were $8,894 of additional capital contributions to CONE Gathering LLC and $78,293 to the Partnership. The capital contributions were offset, in part, by $16,719 of distributions from the Partnership. During the year ended December 31, 2014, there were $87,117 of additional capital contributions to CONE Gathering LLC and no distributions from the Partnership.

Following the CONE Midstream Partners IPO in September 2014, CONE Gathering LLC has a 2% general partner interest in the Partnership, while each sponsor has a 32.1% limited partner interest. CNX Gas Company accounts for its portion of the earnings in the Partnership under the equity method of accounting. At December 31, 2015, CNX Gas Company and Noble Energy each continue to own a 50% interest in the assets of CONE Gathering LLC that were not contributed to the Partnership. Equity in earnings of affiliates for the years ended December 31, 2015, 2014 and 2013 related to CONE Gathering LLC was $20,916, $25,521 and $14,974 respectively. For the year ended December 31, 2015 and 2014 equity in earnings of affiliates related to CONE Midstream Partners LP was $22,883 and $4,286 respectively. There were no equity in earnings related to CONE Midstream Partners LP for the year ended December 31, 2013.

For the years ended December 31, 2015, 2014 and 2013 CONE Gathering LLC (prior to September 30, 2014) and the Partnership (after September 30, 2014) provided gathering services to CNX Gas Company in the ordinary course of business. For the years December 31, 2015, 2014 and 2013 gathering services were $105,368, $65,584 and $35,765 respectively. These costs were included in Exploration and Production Costs - Transportation, Gathering and Compression on CONSOL Energy’s accompanying Consolidated Statements of Income. At December 31, 2015 and December 31, 2014, CONSOL Energy had a net payable of $12,216 and $21,535 respectively, due to both the Partnership and CONE Gathering LLC primarily for accrued but unpaid gathering services and unpaid capital contributions. The net payable for both periods is included in Accounts Payable on CONSOL Energy’s accompanying Consolidated Balance Sheets.

During the year ended December 31, 2015, CONSOL Energy purchased $2,239 of supply inventory from the Partnership. There was no supply inventory purchased during the year ended December 31, 2014.

CNX Coal Resources LP

On July 7, 2015, CNXC closed its initial public offering of 5,000,000 common units representing limited partnership interests at a price to the public of $15.00 per unit. 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.

In connection with the IPO offering, CNXC entered into a $400,000 senior secured revolving credit facility with certain lenders and PNC Bank, National Association, as administrative agent ("PNC"). Obligations under the revolving credit facility are guaranteed by CNXC's subsidiaries (the "guarantor subsidiaries") and are secured by substantially all of CNXC's and CNXC's subsidiaries' assets pursuant to a security agreement and various mortgages. In connection with the new revolving credit facility, CNXC made an initial draw of $200,000, and after origination fees of $3,000, the net proceeds were $197,000.

The total net proceeds related to these transactions that were distributed to CONSOL Energy were $342,711.

CNXC results are fully consolidated. Charges for services from CONSOL Energy include the following:

	For the Years Ended December 31,		
	2015	2014	2013
Operating and Other Costs	$3,709	$4,186	$3,290
Selling and Direct Administrative Expenses	5,085	6,444	5,687
General and Administrative Expenses	3,829	9,303	7,937
Total Services from CONSOL Energy	$12,623	$19,933	$16,914

At December 31, 2015, CNXC had a net payable to CONSOL Energy in the amount of $3,452. This payable includes reimbursements for business expenses, executive fees, debt issuance and financing fees, stock-based compensation and other items.

Supplemental Gas Data (unaudited):

The following information was prepared in accordance with the FASB's Accounting Standards Update No. 2010-03, “Extractive Activities-Oil and Gas (Topic 932).”

Capitalized Costs:

	As of December 31,	
	2015	2014
Proved properties	$1,922,602	$1,768,007
Unproved properties	1,421,083	1,540,835
Intangible drilling costs	3,452,989	2,798,394
Wells and related equipment	785,744	716,748
Gathering assets	1,147,173	1,088,238
Gas well plugging	115,121	111,227
Total Property, Plant and Equipment	8,844,712	8,023,449
Accumulated Depreciation, Depletion and Amortization	(2,691,005)	(1,515,983)
Net Capitalized Costs	$6,153,707	$6,507,466

Costs incurred for property acquisition, exploration and development (*):

	For the Years Ended December 31,		
	2015	2014	2013
Property acquisitions			
Proved properties	$—	$—	$—
Unproved properties	76,676	119,597	260,477
Development	666,315	952,733	629,100
Exploration	95,371	45,006	95,413
Total	$838,362	$1,117,336	$984,990

(*) Includes costs incurred whether capitalized or expensed.

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Results of Operations for Producing Activities:

	For the Years Ended December 31,		
	2015	2014	2013
Natural Gas, NGLs and Oil Sales	$728,458	$1,007,381	$665,614
Gain on Commodity Derivative Instruments	392,942	23,193	75,255
Production Royalty Interests and Purchased Gas Sales	59,631	91,427	69,733
Total Revenue	1,181,031	1,122,001	810,602
Lease Operating Expense	98,997	109,172	96,601
Production, Ad Valorem, and Other Fees	30,438	39,418	28,676
Transportation, Gathering and Compression	356,240	258,110	201,024
Production Royalty Interests and Purchased Gas Costs	46,544	77,197	57,906
Direct Administrative, Selling & Other Costs	46,192	55,004	49,092
Impairment of Exploration and Production Properties	828,905	—	—
Other Costs	10,119	22,718	61,107
DD&A	370,374	323,600	231,809
Total Costs	1,787,809	885,219	726,215
Pre-tax Operating Income / (Loss)	(606,778)	236,782	84,387
Income Taxes / (Benefit)	(229,762)	82,925	32,067
Results of Operations for Producing Activities excluding Corporate and Interest Costs	$(377,016)	$153,857	$52,320

The following is production, average sales price and average production costs, excluding ad valorem and severance taxes, per unit of production:

	For the Years Ended December 31,		
	2015	2014	2013
Production (MMcfe)	328,657	235,714	172,380
Average gas sales price before effects of financial settlements (per Mcf)	$2.22	$4.26	$3.85
Average effects of financial settlements (per Mcf)	$0.60	$0.11	$0.45
Average gas sales price including effects of financial settlements (per Mcf)	$2.82	$4.37	$4.30
Average lifting costs, excluding ad valorem and severance taxes (per Mcf)	$0.30	$0.46	$0.56

During the years ended December 31, 2015, 2014 and 2013, we drilled 132.8, 180.3, and 139.8 net development wells, respectively. There were no net dry development wells in 2015, 2014, or 2013.

During the years ended December 31, 2015, 2014 and 2013, we drilled 2.5, 8.5, and 5.5 net exploratory wells, respectively. There were no net dry exploratory wells in 2015, 2014, or 2013.

At December 31, 2015, there were 18.0 net development wells and no exploratory wells that have been partially drilled but not turned in-line. Additionally there are 49.5 net developmental wells that are drilled but uncompleted and 20 net developmental wells and 1 net exploratory well that have been completed and are awaiting final tie-in to production.

We are committed to provide 270.7 Bcf of gas under existing sales contracts or agreements over the course of the next four years. We expect to produce sufficient quantities from existing proved developed reserves to satisfy these commitments.

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:

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	Gross	Net(1)
Producing Gas Wells (including gob wells)	17,349	12,834
Producing Oil Wells	188	29
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 of 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.

Proved Oil and Gas Reserves Quantities:

Annually, the preparation of natural gas reserves estimates are completed in accordance with CONSOL Energy's prescribed internal control procedures, which include verification of input data into a gas reserves forecasting and economic evaluation software, as well as multi-functional management review. The input data verification includes reviews of the price and cost assumptions used in the economic model to determine the reserves. Also, the production volumes are reconciled between the system used to calculate the reserves and other accounting/measurement systems. The technical employee responsible for overseeing the preparation of the reserve estimates is a petroleum engineer with over 10 years of experience in the oil and gas industry. Our 2015 gas reserves results, which are reported in the Supplemental Gas Data year ended December 31, 2015 Form 10-K, were audited by Netherland, Sewell & Associates, Inc. The technical person primarily responsible for overseeing the audit of our reserves is a registered professional engineer in the state of Texas with over 15 years of experience in the oil and gas industry. The gas reserves estimates are as follows:

	Natural Gas (MMcfe)	NGLs (Mbbls)	Condensate & Crude Oil (Mbbls)	Consolidated Operations (MMcfe)
Balance December 31, 2012 (c)	3,905,437	13,374	1,296	3,993,458
Revisions (a)	176,045	(1,017)	336	171,953
Price Changes	104,728	4	1	104,757
Extensions and Discoveries (b)	1,567,634	9,623	1,343	1,633,426
Production	(168,737)	(438)	(170)	(172,380)
Balance December 31, 2013 (c)	5,585,107	21,546	2,806	5,731,214
Revisions (d)	(46,560)	40,363	3,756	218,168
Price Changes	15,512	—	—	15,512
Extensions and Discoveries (e)	979,801	18,459	1,314	1,098,436
Production	(216,260)	(2,578)	(664)	(235,714)
Balance December 31, 2014 (c)	6,317,600	77,790	7,212	6,827,616
Revisions (f)	1,052,978	45,993	6,662	1,368,909
Price Changes	(2,866,123)	(45,675)	(3,208)	(3,159,421)
Extensions and Discoveries (g)	840,800	13,916	1,707	934,542
Production	(285,041)	(5,812)	(1,458)	(328,657)
Balance December 31, 2015 (c)	5,060,214	86,212	10,915	5,642,989
Proved developed reserves (h):				
December 31, 2013	2,470,412	5,939	1,375	2,514,294
December 31, 2014	2,979,906	32,405	4,061	3,198,706
December 31, 2015	3,310,894	59,196	5,180	3,697,152
Proved undeveloped reserves:				
December 31, 2013	3,114,695	15,607	1,431	3,216,920
December 31, 2014	3,337,694	45,385	3,151	3,628,910
December 31, 2015	1,749,320	27,016	5,736	1,945,837

(a) Revisions are primarily due to corporate planning changes that affect the number of wells (5-Years) forecasted to be drilled in our various areas and reservoirs. These changes along with upward revisions attributable to efficiencies in operations and well performance had the total affect of the positive revisions for 2013.

(b) Extensions and Discoveries in 2013 are primarily due to the addition of wells on our Marcellus Shale acreage more than one offset location away with reliable technology.

(c) Proved developed and proved undeveloped gas reserves are defined by SEC Rule 4.10(a) of Regulation S-X. Generally, these reserves would be commercially recovered under current economic conditions, operating methods and government regulations. CONSOL Energy cautions that there are many inherent uncertainties in estimating proved reserve quantities, projecting future production rates and timing of development expenditures. Proved oil and gas reserves are estimated quantities of natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions and government regulations. Proved developed reserves are reserves expected to be recovered through existing wells, with existing equipment and operating methods.

(d) Revisions for 2014 are primarily due to efficiencies in operations and well optimization and had the total effect of positive revisions. Additionally, the 2014 revisions include a reclassification of ethane volumes from natural gas to NGLs.

(e) Extensions and Discoveries in 2014 are primarily due to the addition of wells on our Marcellus and Utica Shale acreage. We also included Marcellus Shale wells which are more than one offset location away due to continued use of reliable technology.

(f) The upward revisions in 2015 are attributable to efficiencies in operations and well performance.

(g) Extensions and Discoveries in 2015 are due mainly to the high grading of locations which resulted in the addition of wells on our Marcellus and Utica Shale acreage more than one offset location away with continued use of reliable technology.

(h) Included in our proved developed reserves at December 31, 2015 are producing wells with negative undiscounted cash flows that represent 258.1 Bcfe of natural gas and equivalents which represents 4.6% of our total reserves quantities. These consist primarily of conventional wells and the company includes these wells in our reserves as we continue to produce the properties.

	For the Year Ended December 31, 2015
Proved Undeveloped Reserves (MMcfe)	
Beginning proved undeveloped reserves	3,628,910
Undeveloped reserves transferred to developed(a)	(462,010)
Price Changes	(2,625,414)
Plan and other revisions (b)	655,605
Extension and discoveries (c)	748,746
Ending proved undeveloped reserves(d)(e)	1,945,837

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(a) During 2015, various exploration and development drilling and evaluations were completed. Approximately, $330,686 of capital was spent in the year ended December 31, 2015 related to undeveloped reserves that were transferred to developed.

(b) Plan and other revisions are due to high grading of locations. These changes along with upward revisions attributable to efficiencies in operations and well performance had the total affect of a positive revision.

(c) Extensions and discoveries in 2015 are due mainly to the high grading of locations which resulted in the addition of wells on our Marcellus and Utica Shale acreage more than one offset location away with continued use of reliable technology.

(d) Included in proved undeveloped reserves at December 31, 2015 are approximately 215,987 MMcfe of reserves that have been reported for more than five years. These reserves specifically relate to CONSOL Energy's Buchanan Mine, more specifically, to GOB (a rubble zone formed in the cavity created by the extraction of coal) production due to a complex fracture being generated in the overburden strata above the mined seam. Mining operations take a significant amount of time and our GOB forecasts are consistent with the future plans of the Buchanan Mine. Evidence also exists that supports the continual operation of the mine beyond the current plan, unless there was an extreme circumstance resulting from an external factor. These reasons constitute that specific circumstances exist to continue recognizing these reserves for CONSOL Energy.

(e) Included in proved undeveloped reserves at December 31, 2015 are 293 gross proved undeveloped locations that generate positive future net revenue but have negative present worth discounted at 10 percent as of December 31, 2015, representing 36.0% of our total proved undeveloped reserves. Additionally, the 700.9 Bcfe of natural gas and equivalents attributable to these locations represent approximately 12.4% of our total proved reserves. The Company includes these well sites in its current drilling plans and currently intends to drill these sites as our economic modeling of these well locations generate positive future cash flows.

The following table represents the capitalized exploratory well cost activity as indicated:

	December 31, 2015
Costs pending the determination of proved reserves at December 31, 2014	
For a period one year or less	$24,647
For a period greater than one year but less than five years	12,893
For a period greater than five years	—
Total	$37,540

December 31, 2015	2014	2013
$17,179	$27,453	$12,140

Costs reclassified to wells, equipment and facilities based on the determination of proved reserves			
Costs expensed due to determination of dry hole or abandonment of project	$—	$2,041	$8,596

CONSOL Energy's proved natural gas reserves are located in the United States.

Standardized Measure of Discounted Future Net Cash Flows:

The following information has been prepared in accordance with the provisions of the Financial Accounting Standards Board's Accounting Standards Update No. 2010-03, “Extractive Activities-Oil and Gas (Topic 932).” This topic requires the standardized measure of discounted future net cash flows to be based on the average, first-day-of-the-month price for the year. Because prices used in the calculation are average prices for that year, the standardized measure could vary significantly from year to year based on the market conditions that occurred.

The projections should not be viewed as realistic estimates of future cash flows, nor should the “standardized measure” be interpreted as representing current value to CONSOL Energy. Material revisions to estimates of proved reserves may occur in the future; development and production of the reserves may not occur in the periods assumed; actual prices realized are expected to vary significantly from those used; and actual costs may vary. CONSOL Energy's investment and operating decisions are not based on the information presented, but on a wide range of reserve estimates that include probable as well as proved reserves and on different price and cost assumptions.

The standardized measure is intended to provide a better means for comparing the value of CONSOL Energy's proved reserves at a given time with those of other gas producing companies than is provided by a comparison of raw proved reserve quantities.

	December 31,		
	2015	2014	2013
Future Cash Flows:			
Revenues	$11,837,732	$28,502,852	$21,602,594
Production costs	(6,584,947)	(10,100,868)	(7,105,962)
Development costs	(1,220,010)	(3,368,621)	(3,902,875)
Income tax expense	(1,532,454)	(5,711,989)	(4,025,626)
Future Net Cash Flows	2,500,321	9,321,374	6,568,131
Discounted to present value at a 10% annual rate	(1,481,017)	(6,337,216)	(4,887,320)
Total standardized measure of discounted net cash flows	$1,019,304	$2,984,158	$1,680,811

The following are the principal sources of change in the standardized measure of discounted future net cash flows for consolidated operations during:

	December 31,		
	2015	2014	2013
Balance at beginning of period	$2,984,158	$1,680,811	$736,206
Net changes in sales prices and production costs	(4,151,684)	517,731	1,295,956
Sales net of production costs	(589,533)	(559,563)	(365,477)
Net change due to revisions in quantity estimates	408,006	151,233	132,900
Net change due to extensions, discoveries and improved recovery	157,016	418,775	383,308
Development costs incurred during the period	666,315	952,733	625,824
Difference in previously estimated development costs compared to actual costs incurred during the period	8,911	(102,949)	(123,976)
Changes in estimated future development costs	374,982	595,221	(486,518)
Net change in future income taxes	1,259,744	(798,470)	(578,951)
Accretion of discount and other	(98,611)	128,636	61,539
Total discounted cash flow at end of period	$1,019,304	$2,984,158	$1,680,811

Supplemental Coal Data (unaudited)

	Millions of Tons For the Year Ended December 31,				
	2015	2014	2013	2012	2011
Proven and probable coal reserves at beginning of period	3,238	3,032	4,229	4,314	4,229
Purchased reserves	24	—	1	—	6
Reserves sold in place	(43)	(233)	(1,199)	(155)	—
Production	(29)	(32)	(55)	(55)	(62)
Revisions and other changes	(143)	471	56	125	141
Consolidated proven and probable coal reserves at end of period* (1)	3,047	3,238	3,032	4,229	4,314
Proportionate share of proven and probable coal reserves of unconsolidated equity affiliates (excluded from the table above)*	—	55	57	41	145

* Proven and probable coal reserves are the equivalent of “demonstrated reserves” under the coal resource classification system of the U.S. Geological Survey. Generally, these reserves would be commercially mineable at year-end prices and cost levels, using current technology and mining practices.

(1) 143.3 Million tons for the Mason Dixon Project are controlled by CCC, a former subsidiary of CONSOL Energy that was sold in December 2013. As of filing, these tons are still controlled by CCC 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.

CONSOL Energy's coal reserves are located in nearly every major coal-producing region in North America. At December 31, 2015, 315 million tons were assigned to mines either in production or temporarily idled. The proven and probable coal reserves at December 31, 2015 include 2,531 million tons of thermal coal reserves, of which approximately 4 percent has a sulfur content equivalent to less than 1.2 pounds sulfur dioxide per million British thermal unit (Btu), 11 percent has a sulfur content equivalent to between 1.2 and 2.5 pounds sulfur dioxide per million Btu, and 85 percent has a sulfur content equivalent to greater than 2.5 pounds sulfur dioxide per million Btu. The reserves also include 516 million tons of metallurgical coal in consolidated reserves, of which approximately 37 percent has a sulfur content equivalent to less than 1.2 pounds sulfur dioxide per million Btu and 63 percent has a sulfur content equivalent to between 1.2 and 2.5 pounds sulfur dioxide per million Btu.

Our estimate of proven and probable coal reserves has been determined by CONSOL Energy’s geologists and mining engineers. CONSOL Energy 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 factor. The 2014 re-evaluations resulted in 407 million of the total 471 million additional tons of proven and probable reserves added as result of revisions and other changes in 2014. During 2014, an independent third-party audited approximately 86% of the above revisions and other changes that occurred in 2014.

Supplemental Quarterly Information (unaudited):
(Dollars in thousands, except per share data)

	Three Months Ended			
	March 31, 2015	June 30, 2015	September 30, 2015	December 31, 2015
Sales (A)	$842,835	$604,680	$723,955	$696,855
Freight Revenue	$6,525	$4,251	$3,219	$11,602
Costs and Expenses (B)	$494,321	$442,520	$359,181	$331,881
Freight Expense	$6,525	$4,251	$3,219	$11,602
Income (Loss) from Continuing Operations (C)	$79,031	$(603,301)	$125,470	$34,325
Income from Discontinued Operations	$—	$—	$—	$—
Net Income (Loss) Attributable to CONSOL Energy Inc Shareholders	$79,031	$(603,301)	$118,980	$30,405
Earnings Per Share				
Basic:				
Income (Loss) from Continuing Operations	$0.34	$(2.64)	$0.52	$0.13
Income from Discontinued Operations	$—	$—	$—	$—
Net Income (Loss)	$0.34	$(2.64)	$0.52	$0.13
Dilutive:				
Income (Loss) from Continuing Operations	$0.34	$(2.64)	$0.52	$0.13
Income from Discontinued Operations	$—	$—	$—	$—
Net Income (Loss)	$0.34	$(2.64)	$0.52	$0.13

	Three Months Ended			
	March 31, 2014	June 30, 2014	September 30, 2014	December 31, 2014
Sales (A)	$900,485	$855,867	$833,806	$857,794
Freight Revenue	$9,945	$10,109	$2,497	$5,597
Costs and Expenses (B)	$563,141	$615,912	$596,770	$563,331
Freight Expense	$9,945	$10,109	$2,497	$5,597
Income (Loss) from Continuing Operations	$121,691	$(24,935)	$(1,645)	$73,666
Loss from Discontinued Operations	$(5,687)	$—	$—	$—
Net Income (Loss) Attributable to CONSOL Energy Inc Shareholders	$116,004	$(24,935)	$(1,645)	$73,666
Earnings Per Share				
Basic:				
Income (Loss) from Continuing Operations	$0.53	$(0.11)	$(0.01)	$0.32
Loss from Discontinued Operations	$(0.02)	$—	$—	$—
Net Income (Loss)	$0.51	$(0.11)	$(0.01)	$0.32
Dilutive:				
Income (Loss) from Continuing Operations	$0.53	$(0.11)	$(0.01)	$0.32
Loss from Discontinued Operations	$(0.03)	$—	$—	$—
Net Income (Loss)	$0.50	$(0.11)	$(0.01)	$0.32

(A) Includes natural gas, NGLs, and oil sales; gain on commodity derivative instruments; coal sales; other outside sales; and production royalty interests and purchased gas sales.
(B) Includes exploration and production costs, coal costs, and miscellaneous operating expense, excluding DD&A, other corporate expenses, general and administrative, loss on debt extinguishment, interest expense and freight expense.

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(C) Includes an impairment of $828,905 that was recorded during the three months ended June 30, 2015 related to CONSOL Energy's exploration and production properties. The impairment primarily related to the write down of the Company's shallow oil and gas asset values including impairments to unproved property. See Note 1 - Significant Accounting Policies in Item 8 of this Form 10-K for additional information.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure controls and procedures. CONSOL Energy, under the supervision and with the participation of its management, including CONSOL Energy’s principal executive officer and principal financial officer, evaluated the effectiveness of the Company’s “disclosure controls and procedures,” as such term is defined in Rule 13a-15(e) under the Securities Act of 1934, as amended (the “Exchange Act”), as of the end of the period covered by this Annual Report on Form 10-K. Based on that evaluation, CONSOL Energy’s principal executive officer and principal financial officer have concluded that the Company’s disclosure controls and procedures are effective as of December 31, 2015 to ensure that information required to be disclosed by CONSOL Energy in reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission rules and forms, and includes controls and procedures designed to ensure that information required to be disclosed by CONSOL Energy in such reports is accumulated and communicated to CONSOL Energy’s management, including CONSOL Energy’s principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure.

Management's Annual Report on Internal Control Over Financial Reporting. CONSOL Energy's management is responsible for establishing and maintaining adequate internal control over financial reporting. CONSOL Energy's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

CONSOL Energy's internal control over financial reporting includes policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of assets; (2) provide reasonable assurances that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures are being made only in accordance with authorizations of management and the directors of CONSOL Energy; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of CONSOL Energy's assets that could have a material effect on our financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of CONSOL Energy's internal control over financial reporting as of December 31, 2015. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (COSO) in Internal Control-Integrated Framework. Based on our assessment and those criteria, management has concluded that CONSOL Energy maintained effective internal control over financial reporting as of December 31, 2015.

The effectiveness of CONSOL Energy's internal control over financial reporting as of December 31, 2015 has been audited by Ernst and Young, an independent registered public accounting firm, as stated in their report set forth in the Report of Independent Registered Public Accounting Firm in Part II, Item 9a of this annual report on Form 10-K.

Changes in internal controls over financial reporting. There were no changes in the Company's internal controls over financial reporting that occurred during the fourth quarter of the fiscal year covered by this Annual Report on Form 10-K that have materially affected, or are reasonably likely to materially affect, the Company’s internal control over financial reporting.

Report of Independent Registered Public Accounting Firm
The Board of Directors and Stockholders of CONSOL Energy Inc. and Subsidiaries

We have audited CONSOL Energy Inc. and Subsidiaries' internal control over financial reporting as of December 31, 2015, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission 2013 framework (the COSO criteria). CONSOL Energy Inc. and Subsidiaries' management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Annual Report on Internal Control Over Financial Reporting appearing under Item 9a. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, CONSOL Energy Inc. and Subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of CONSOL Energy Inc. and Subsidiaries as of December 31, 2015 and 2014, and the related consolidated statements of income, comprehensive income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2015 of CONSOL Energy Inc. and Subsidiaries and our report dated February 5, 2016 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Pittsburgh, Pennsylvania
February 5, 2016

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ITEM 9B. OTHER INFORMATION

NONE

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by this Item is incorporated herein by reference from the information under the captions "PROPOSAL NO. 1-ELECTION OF DIRECTORS-Biographies of Nominees," "BOARD OF DIRECTORS AND COMPENSATION INFORMATION and "SECTION 16(a) BENEFICIAL OWNERSHIP REPORTING COMPLIANCE" in the Proxy Statement for the annual meeting of shareholders to be held on May 11, 2016 (the "Proxy Statement").

Executive Officers of CONSOL Energy

The following is a list, as of February 1, 2016, of CONSOL Energy executive officers, their ages and their positions and offices held with CONSOL Energy.

Name	Age	Position
Nicholas J. DeIuliis	47	President and Chief Executive Officer
Stephen W. Johnson	57	Executive Vice President - Chief Administrative Officer
David M. Khani	52	Executive Vice President and Chief Financial Officer
James C. Grech	54	Executive Vice President and Chief Commercial Officer
Timothy C. Dugan	54	Chief Operating Officer - Exploration and Production
James A. Brock	59	Chief Operating Officer - Coal

Nicholas J. DeIuliis has been President of CONSOL Energy since February 23, 2011 and on May 7, 2014 he was named CONSOL's Chief Executive Officer. Mr. DeIuliis previously served in various positions at CNX Gas Corporation, including President, Chief Executive Officer and Chief Operating Officer. He is currently Chairman of the Board at CNX Gas Corporation. He was Executive Vice President and Chief Operating Officer of CONSOL Energy from January 16, 2009 until February 23, 2011. Prior to that time, he held the following positions at CONSOL Energy: Senior Vice President - Strategic Planning (November 1, 2004 to August 2005); Vice President Strategic Planning (April 1, 2002 to November 1, 2004); Director-Corporate Strategy (October 1, 2001 to April 1, 2002); Manager-Strategic Planning (January 1, 2001 to October 2001); and Supervisor-Process Engineering (April 1, 1999 to January 1, 2001). He was appointed a directed and elected Chairman of the Board of the general partner of CNX Coal Resources, LP effective March 16, 2015.

Stephen W. Johnson has been Executive Vice President and Chief Administrative officer of CONSOL Energy and CNX Gas Corporation since April 13, 2015. From December 31, 2012 until April 13, 2015, he served as Executive Vice President and Chief Legal and Corporate Affairs Officer of CONSOL Energy and CNX Gas Corporation. Prior to that time, Mr. Johnson served as Senior Vice President and General Counsel of CONSOL Energy and CNX Gas Corporation from February 5, 2009 through December 31, 2012. Prior to February 5, 2009, he served in the following positions with CNX Gas Corporation: General Counsel (September 1, 2005 to December 2, 2005); Senior Vice President and General Counsel (December 2, 2005 to June 21, 2007); and Executive Vice President, General Counsel and Secretary (June 21, 2007 to February 5, 2009). Effective May 30, 2014, Mr. Johnson became a director of the general partnership of CONE Midstream Partners LP. He was appointed a director of the general partner of CNX Coal Resources, LP effective March 16, 2015.

David M. Khani joined CONSOL Energy on September 1, 2011 as its Vice President - Finance, and was promoted to Executive Vice President and Chief Financial Officer effective March 1, 2013. Prior to joining CONSOL Energy, Mr. Khani was with FBR Capital Markets & Co. ("FBR"), an investment banking and advisory firm and held the following positions: Director of Research from February 2007 through October 2010, and then Co-Director of Research from November 2010 through August 2011. Effective May 30, 2014, Mr. Khani became a director and the Chief Financial Officer of the general partnership of CONE Midstream Partners LP. He was appointed a director of the general partner of CNX Coal Resources, LP effective March 16, 2015.

James C. Grech became Chief Commercial Officer on November 15, 2012 and was promoted to Executive Vice President and Chief Commercial Officer effective March 1, 2013. Mr. Grech had served as Senior Vice President of CNX Land Resources Inc., a subsidiary of CONSOL Energy from September 13, 2011 until December 5, 2013. He joined the company in 2001 as Vice

President of Business Development and was promoted to Senior Vice President - Marketing of CONSOL Energy Sales Company, another subsidiary of CONSOL Energy, a position he held from August 15, 2005 to October 25, 2011.

Timothy C. Dugan has been Chief Operating Officer- Exploration & Production of CONSOL Energy since January 28, 2014. He was President and Chief Operating Office of CNX Gas Corporation from May 22, 2014 to December 1, 2014, when he became President and Chief Executive Officer. Prior to joining CONSOL Energy, Mr. Dugan was Vice President - Appalachia South Business Unit at Chesapeake Energy Corporation. During his seven years with Chesapeake Energy, he held the titles of Senior Asset Manager, Operations Superintendent, Senior Asset Manager and District Manager. From 2001 to 2007, Mr. Dugan was employed with EQT Corporation, where he held the titles of Regional Reservoir Engineer and Director of Operations - Engineering.

James A. Brock has been Chief Operating Officer - Coal of CONSOL Energy since December 10, 2010. Prior to this appointment, he served as Senior Vice President - Northern Appalachia - West Virginia Operations of CONSOL Energy beginning December 3, 2007. From September 7, 2006 until December 3, 2007 he served as Vice President-Operations. Mr. Brock began his career with CONSOL Energy in 1979 at the Matthews Mine and since then has served at various locations in many positions including Section Foreman, Mine Longwall Coordinator, General Mine Foreman, and Superintendent. Mr. Brock was appointed the Chief Executive Officer and a director of the general partner of CNX Coal Resources, LP effective March 16, 2015.

CONSOL Energy has a written Code of Business Conduct that applies to CONSOL Energy's Chief Executive Officer (Principal Executive Officer), Chief Financial Officer (Principal Financial Officer) and others. The Code of Business Conduct is available on CONSOL Energy's website at www.consolenergy.com. Any amendments to, or waivers from, a provision of our code of employee business conduct and ethics that applies to our principal executive officer, our principal financial and accounting officer and that relates to any element of the code of ethics enumerated in paragraph (b) of Item 406 of Regulation S-K shall be disclosed by posting such information on our website at www.consolenergy.com.

By certification dated June 3, 2015, CONSOL Energy's Chief Executive Officer certified to the New York Stock Exchange (NYSE) that he was not aware of any violation by the Company of the NYSE corporate governance listing standards. In addition, the required Sarbanes-Oxley Act, Section 302 certifications regarding the quality of our public disclosures were filed by CONSOL Energy as exhibits to this Form 10-K.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this Item is incorporated by reference from the information under the captions “BOARD OF DIRECTORS AND COMPENSATION INFORMATION and “EXECUTIVE COMPENSATION INFORMATION” (excluding the Compensation Committee Report) in the Proxy Statement.

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

The information required by this Item is incorporated by reference from the information under the captions “BENEFICIAL OWNERSHIP OF SECURITIES” and “SECURITIES AUTHORIZED FOR ISSUANCE UNDER CONSOL ENERGY EQUITY COMPENSATION PLAN” in the Proxy Statement.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

The information requested by this Item is incorporated by reference from the information under the caption "PROPOSAL NO. 1-ELECTION OF DIRECTORS - Related Party Policy and Procedures and PROPOSAL NO. 1 - ELECTION OF DIRECTORS - Determination of Director Independence in the Proxy Statement.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by this Item is incorporated by reference from the information under the caption "ACCOUNTANTS AND AUDIT COMMITTEE-INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM" in the Proxy Statement.

PART IV

ITEM 15. EXHIBIT INDEX

In reviewing any agreements incorporated by reference in this Form 10-K or filed with this 10-K, please remember that such agreements are included to provide information regarding their terms. They are not intended to be a source of financial, business or operational information about CONSOL Energy or any of its subsidiaries or affiliates. The representations, warranties and covenants contained in these agreements are made solely for purposes of the agreements and are made as of specific dates; are solely for the benefit of the parties; may be subject to qualifications and limitations agreed upon by the parties in connection with negotiating the terms of the agreements, including being made for the purpose of allocating contractual risk between the parties instead of establishing matters as facts; and may be subject to standards of materiality applicable to the contracting parties that differ from those applicable to investors or security holders. Investors and security holders should not rely on the representations, warranties and covenants or any description thereof as characterizations of the actual state of facts or condition of CONSOL Energy or any of its subsidiaries or affiliates or, in connection with acquisition agreements, of the assets to be acquired. Moreover, information concerning the subject matter of the representations, warranties and covenants may change after the date of the agreements. Accordingly, these representations and warranties alone may not describe the actual state of affairs as of the date they were made or at any other time.

(A)(1)	Financial Statements Contained in Item 8 hereof.
(A)(2)	Financial Statement Schedule-Schedule II Valuation and qualifying accounts.
2.1	Asset Acquisition Agreement dated August 17, 2011 between CNX Gas Company LLC and Noble Energy, Inc., incorporated by reference to Exhibit 2.1 to Form 8-K (file no. 001-14901) filed on August 18, 2011.
2.2	Joint Development Agreement by and among CNX Gas Company LLC and Noble Energy, Inc. dated as of September 30, 2011, incorporated by reference to Exhibit 2.2 to Form 10-Q (file no. 001-14901) for the quarter ended September 30, 2011, filed on October 31, 2011.
2.3	Stock Purchase Agreement, dated October 25, 2013, among CONSOL Energy Inc., Consolidation Coal Company, Ohio Valley Resources, Inc., and, as to certain provisions of the Purchase Agreement, Murray Energy Corporation, incorporated by reference to Exhibit 2.1 to Form 8-K (file no. 001-14901) filed on December 11, 2013.
3.1	Restated Certificate of Incorporation of CONSOL Energy Inc., incorporated by reference to Exhibit 3.1 to Form 8-K (file no. 001-14901) filed on May 8, 2006.
3.2	Amended and Restated Bylaws of CONSOL Energy Inc., dated as of December 9, 2014, incorporated by reference to Exhibit 3.1 to Form 8-K (file no. 001-14901) filed on December 10, 2014.
4.1	Supplemental Indenture, dated as of April 30, 2010, among Dominion Exploration & Production, Inc., Dominion Reserves, Inc., Dominion Coalbed Methane, Inc., Dominion Appalachian Development, LLC, Dominion Appalachian Development Properties, LLC, CONSOL Energy Inc. and The Bank of Nova Scotia Trust Company of New York, as trustee, with respect to the 8.25% Senior Notes due 2020, incorporated by reference to Exhibit 4.6 to Form 8-K/A (file no. 001-14901) filed on August 6, 2010.
4.2	Supplemental Indenture No. 2, dated as of June 16, 2010, among Cardinal States Gathering Company, CNX Gas Company LLC, CNX Gas Corporation, Coalfield Pipeline Company, Knox Energy, LLC, MOB Corporation, CONSOL Energy Inc. and The Bank of Nova Scotia Trust Company of New York, as trustee, with respect to the 8.25% Senior Notes due 2020, incorporated by reference to Exhibit 4.7 to Form 8-K/A (file no. 001-14901) filed on August 6, 2010.
4.3	Supplemental Indenture No. 3, dated as of August 24, 2011, to Indenture dated as of April 1, 2010 among CONSOL Energy Inc., certain subsidiaries of CONSOL Energy Inc. and The Bank of Nova Scotia Trust Company of New York, as trustee, with respect to the 8.25% Senior Notes due 2020, incorporated by reference to Exhibit 4.2 to Form 8-K (file no. 001-14901) filed on August 29, 2011.
4.4	Supplemental Indenture No. 4, dated as of September 10, 2013, to Indenture dated as of April 1, 2010, by and among CONSOL Energy Inc., certain subsidiaries of CONSOL Energy Inc. and Wells Fargo Bank,

	National Association, as successor trustee to The Bank of Nova Scotia Trust Company of New York, with respect to the 8.25% Senior Notes due 2020, incorporated by reference to Exhibit 4.2 of Form 10-Q (file no. 001-14901) filed on November 1, 2013.
4.5	Supplemental Indenture No. 5, dated as of March 23, 2015, to the Indenture dated as of April 1, 2010 by and among CONSOL Energy Inc., the Subsidiary Guarantors listed on the signature pages thereof and Wells Fargo Bank, National Association, a national banking association, as successor trustee, with respect to the 8.25% Senior Notes due 2020, incorporated by reference to Exhibit 4.4 of Form 10-Q (file no. 001-14901) filed on May 5, 2015.
4.6	Indenture, dated as of March 9, 2011, among CONSOL Energy Inc., the Subsidiaries named therein and The Bank of Nova Scotia Trust Company of New York, as trustee, with respect to the 6.375% Senior Notes due 2021, incorporated by reference to Exhibit 4.1 to Form 8-K (file no. 001-14901) filed on March 11, 2011.

4.7	Supplemental Indenture No. 1, dated as of August 24, 2011, to Indenture dated as of March 9, 2011 among CONSOL Energy Inc., certain subsidiaries of CONSOL Energy Inc. and The Bank of Nova Scotia Trust Company of New York, as trustee, with respect to the 6.375% Senior Notes due 2021, incorporated by reference to Exhibit 4.3 to Form 8-K (file no. 001-14901) filed on August 29, 2011.
4.8	Supplemental Indenture No. 2, dated as of September 10, 2013, to Indenture dated as of March 9, 2011, by and among CONSOL Energy Inc., certain subsidiaries of CONSOL Energy Inc. and Wells Fargo Bank, National Association, as successor trustee to The Bank of Nova Scotia Trust Company of New York, with respect to the 6.375 % Senior Notes due 2021, incorporated by reference to Exhibit 4.3 of Form 10-Q (file no. 001-14901) filed on November 1, 2013.
4.9	Supplemental Indenture No. 3, dated as of March 23, 2015, to the Indenture dated as of March 9, 2011 by and among CONSOL Energy Inc., the Subsidiary Guarantors listed on the signature pages thereof and Wells Fargo Bank, National Association, a national banking association, as successor trustee, with respect to the 6.375% Senior Notes due 2021, incorporated by reference to Exhibit 4.3 of Form 10-Q (file no. 001-14901) filed on May 5, 2015.
4.10	Indenture, dated as of April 16, 2014, among CONSOL Energy Inc., the Subsidiary Guarantors named therein and Wells Fargo Bank, National Association, a national banking association, as trustee, with respect to the 5.875% Senior Notes due 2022, incorporated by reference to Exhibit 4.1 to Form 8-K (file no. 001-14901) filed on April 16, 2014.
4.11	Indenture, dated as of March 30, 2015, among CONSOL Energy Inc., the subsidiary guarantors party thereto and Well Fargo, National Association, as Trustee, incorporated by reference to Exhibit 4.1 to Form 8-K (file no. 001-14901) filed on March 30, 2015.
4.12	Registration Rights Agreement, dated as of April 16, 2014, by and among CONSOL Energy Inc., the guarantors signatory thereto and J.P. Morgan Securities LLC and Credit Suisse Securities (USA) LLC, as representatives of the several initial purchasers, incorporated by reference to Exhibit 4.2 to Form 8-K (file no. 001-14901) filed on April 16, 2014.
4.13	Registration Rights Agreement, dated as of August 12, 2014, by and among CONSOL Energy Inc., the guarantors signatory thereto and Goldman, Sachs & Co., as the initial purchasers, incorporated by reference to Exhibit 4.2 to Form 8-K (file no. 001-14901) filed on August 12, 2014.
4.14	Registration Rights Agreement, dated as of March 30, 2015, among CONSOL Energy Inc., the subsidiary guarantors party thereto and Goldman, Sachs & Co. as the initial purchaser named therein, incorporated by reference to Exhibit 4.2 to Form 8-K (file no. 001-14901) filed on March 30, 2015.
4.15	Agreement of Resignation, Appointment and Acceptance, dated July 22, 2013, by and among CONSOL Energy Inc., certain subsidiaries of CONSOL Energy Inc. signatory thereto, Wells Fargo Bank, National Association, as Successor Trustee to The Bank of Nova Scotia Trust Company of New York, and The Bank of Nova Scotia Trust Company of New York, as Resigning Trustee (related to the Indenture dated as of April 1, 2010 with respect to the 8.00% Senior Notes due 2017, the Indenture dated as of April 1, 2010 with respect to the 8.25% Senior Notes due 2020, and the Indenture dated as of March 9, 2011 with respect to the 6.375% Senior Notes due 2021), incorporated by reference to Exhibit 4.4 of Form 10-Q (file no. 001-14901) filed on November 1, 2013.
10.1	Purchase and Sale Agreement, dated as of April 30, 2003, by and among CONSOL Energy Inc., CONSOL Sales Company, CONSOL of Kentucky Inc., CONSOL Pennsylvania Coal Company, Consolidation Coal Company, Island Creek Coal Company, Windsor Coal Company, McElroy Coal Company, Keystone Coal Mining Corporation, Eighty-Four Mining Company, CNX Gas Company LLC, CNX Marine Terminals Inc. and CNX Funding Corporation, incorporated by reference to Exhibit 10.30 to Form 10-Q (file no. 001-14901) for the quarter ended June 30, 2003, filed on August 13, 2003.
10.2	First Amendment to Purchase and Sale Agreement dated as of April 30, 2007, entered into among CONSOL Energy Inc., CONSOL Energy Sales Company, CONSOL of Kentucky Inc., CONSOL Pennsylvania Coal Company, Consolidation Coal Company, Island Creek Coal Company, Windsor Coal Company, McElroy Coal Company, Keystone Coal Mining Corporation, Eighty-Four Mining Company and CNX Marine

	Terminals Inc., each an “Originator” and CNX Funding Corporation, incorporated by reference to Exhibit 10.31 to Form 10-K for the year ended December 31, 2007 (file no. 001-14901), filed on February 19, 2008.
10.3	Second Amendment to Purchase and Sale Agreement dated as of November 16, 2007, entered into among CONSOL Energy Inc. (“CONSOL Energy”), CONSOL Energy Sales Company, CONSOL of Kentucky Inc., Consol Pennsylvania Coal Company LLC, Consolidation Coal Company, Island Creek Coal Company, McElroy Coal Company, Keystone Coal Mining Corporation, Eighty-Four Mining Company and CNX Marine Terminals Inc. (each an “Existing Originator”) and collectively the “Existing Originators”), Fola Coal Company, LLC., Little Eagle Coal Company, LLC., Mon River Towing, Inc., Terry Eagle Coal Company, LLC., Tri-River Fleeting Harbor Service, Inc., and Twin Rivers Towing Company (each, a “New Originator” and collectively the “New Originators”; the Existing Originators and the New Originators, each an “Originator” and collectively, the “Originators”), Windsor Coal Company (the “Released Originator”) and CNX Funding Corporation, incorporated by reference to Exhibit 10.32 to Form 10-K for the year ended December 31, 2007 (file no. 001-14901), filed on February 19, 2008.

10.4	Third Amendment to the Purchase and Sale Agreement, dated as of March 12, 2010, among CNX Marine Terminals Inc., CONSOL Energy Inc., CONSOL Energy Sales Company, CONSOL of Kentucky Inc., CONSOL Pennsylvania Coal Company LLC, Consolidated Coal Company, Eighty-Four Mining Company, Fola Coal Company, L.L.C., Island Creek Coal Company, Keystone Coal Mining Corporation, Little Eagle Coal Company, L.L.C., McElroy Coal Company, Mon River Towing, Inc., Terry Eagle Coal Company, L.L.C., Twin Rivers Towing Company and CNX Funding Corporation, incorporated by reference to Exhibit 10.6 to Form 8-K (file no. 001-14901) filed on March 16, 2010.
10.5	Services Agreement, dated as of April 1, 2010, by and among CONSOL Energy Inc. and its subsidiaries (other than CNX Gas Corporation and its subsidiaries) and (b) CNX Gas Corporation and its subsidiaries, incorporated by reference to Exhibit 99(D)(11) of the Schedule TO filed on April 28, 2010.
10.6	Amended and Restated Receivable Purchase Agreement, dated as of April 30, 2007, by and among CNX Funding Corporation, CONSOL Energy Inc., CONSOL Energy Sales Company, CONSOL of Kentucky Inc., CONSOL Pennsylvania Coal Company, Consolidation Coal Company, Island Creek Coal Company, Windsor Coal Company, McElroy Coal Company, Keystone Coal Mining Corporation, Eighty-Four Mining Company, CNX Marine Terminals Inc., Market Street Funding LLC, Liberty Street Funding LLC, PNC Bank, National Association, and the Bank of Nova Scotia, incorporated by reference to Exhibit 10.33 to Form 10-K for the year ended December 31, 2007 (file no. 001-14901), filed on February 19, 2008.
10.7	First Amendment to Amended and Restated Receivables Purchase Agreement, dated as of May 9, 2007, entered into among CNX Funding Corporation, CONSOL Energy Inc., as the initial Servicer, the Conduit Purchasers listed on the signature pages thereto, the Purchaser Agents listed on the signature pages thereto, the LC Participants listed on the signature pages thereto and PNC Bank, National Association, as Administrator and as LC Bank, incorporated by reference to Exhibit 10.34 to Form 10-K for the year ended December 31, 2007 (file no. 001-14901), filed on February 19, 2008.
10.8	Second Amendment to Amended and Restated Receivables Purchase Agreement, dated as of July 27, 2007, entered into among CNX Funding Corporation, CONSOL Energy Inc., as the initial Servicer (in such capacity, the “Servicer”), the Conduit Purchasers listed on the signature pages thereto, the Purchaser Agents listed on the signature pages thereto, the LC Participants listed on the signature pages thereto and PNC Bank, National Association, as Administrator and as LC Bank, incorporated by reference to Exhibit 10.35 to Form 10-K for the year ended December 31, 2007 (file no. 001-14901), filed on February 19, 2008.
10.9	Third Amendment to Amended and Restated Receivables Purchase Agreement, dated as of November 16, 2007, entered into among CNX Funding Corporation, CONSOL Energy Inc., as the initial Servicer, the various new sub-servicers listed on the signature pages thereto, the Conduit Purchasers listed on the signature pages thereto, the Purchaser Agents listed on the signature pages thereto, the LC Participants listed on the signature pages thereto and PNC Bank, National Association, as Administrator and as LC Bank, incorporated by reference to Exhibit 10.36 to Form 10-K for the year ended December 31, 2007 (file no. 001-14901), filed on February 19, 2008.
10.10	Fourth Amendment to Amended and Restated Receivables Purchase Agreement, dated as of April 27, 2009, among CNX Funding Corporation, CONSOL Energy Inc., as the initial Servicer, the various Sub-Servicers listed on the signature pages thereto, the Conduit Purchasers listed on the signature pages thereto, the Purchaser Agents listed on the signature pages thereto, the LC Participants listed on the signature pages thereto, and PNC Bank, National Association, as Administrator and as LC Bank, incorporated by reference to Exhibit 10.4 to Form 8-K (file no. 001-14901) filed on March 16, 2010.
10.11	Fifth Amendment to Amended and Restated Receivables Purchase Agreement and Waiver, dated as of March 12, 2010, among CNX Funding Corporation, CONSOL Energy Inc., as the initial Servicer, the various Sub-Servicers listed on the signature pages thereto, the Conduit Purchasers listed on the signature pages thereto, the Purchaser Agents listed on the signature pages thereto, the LC Participants listed on the signature pages thereto, and PNC Bank, National Association, as Administrator and as LC Bank, incorporated by reference to Exhibit 10.5 to Form 8-K (file no. 001-14901) filed on March 16, 2010.
10.12	

	Sixth Amendment to Amended and Restated Receivables Purchase Agreement, dated as of April 23, 2010, among CNX Funding Corporation, CONSOL Energy Inc., as the initial Servicer, the various Sub-Servicers listed on the signature pages of the Amendment, the Conduit Purchasers listed on the signature pages of the Amendment, the Purchaser Agents listed on the signature pages of the Amendment, the LC Participants listed on the signature pages of the Amendment and PNC Bank, National Association, as Administrator and as LC Bank, incorporated by reference to Exhibit 10.13 to Form 10-K for the year ended December 31, 2010 (file no. 001-14901), filed on February 10, 2011.
10.13	Seventh Amendment to Amended and Restated Receivables Purchase Agreement, dated as of March 30, 2012, among CNX Funding Corporation, CONSOL Energy Inc., as the initial Servicer, the various Sub-Servicers listed on the signature pages of the Amendment, the Conduit Purchasers listed on the signature pages of the Amendment, the Purchaser Agents listed on the signature pages of the Amendment, the LC Participants listed on the signature pages of the Amendment and PNC Bank, National Association, as Administrator and as LC Bank, incorporated by reference to Exhibit 10.5 to Form 10-Q for the quarter ended March 31, 2012 (file no. 001-14901), filed on April 30, 2012.

10.14	Eighth Amendment to Amended and Restated Receivables Purchase Agreement, dated as of November 8, 2012, by and among CNX Funding Corporation, CONSOL Energy Inc., as the initial Servicer, the Sub-Servicers listed on the signature pages thereto, the Conduit Purchasers listed on the signature pages thereto, the Purchaser Agents listed on the signature pages thereto, the LC Participants listed on the signature pages thereto, and PNC Bank, National Association, as Administrator, and as LC Bank, incorporated by reference to Exhibit 10.1 of Form 10-Q (file no. 001-14901) for the quarter ended March 31, 2014, filed on May 6, 2014.
10.15	Ninth Amendment to Amended and Restated Receivables Purchase Agreement, dated September 23, 2013, by and among CNX Funding Corporation, CONSOL Energy Inc., as the initial Servicer, the Sub-Servicers listed on the signature pages thereto, the Conduit Purchasers listed on the signature pages thereto, the Purchaser Agents listed on the signature pages thereto, the LC Participants listed on the signature pages thereto, Market Street Funding LLC, as Assignor, and PNC Bank, National Association, as Administrator, as LC Bank and as Assignee, incorporated by reference to Exhibit 10.1 of Form 10-Q (file no. 001-14901) for the quarter ended September 30, 2013, filed on November 1, 2013.
10.16	Tenth Amendment to Amended and Restated Receivables Purchase Agreement, dated as of March 28, 2014, by and among CNX Funding Corporation, as seller, CONSOL Energy Inc., as the initial Servicer, the Sub-Servicers listed on the signature pages thereto, the Conduit Purchasers listed on the signature pages thereto, the Purchaser Agents listed on the signature pages thereto, the LC Participants listed on the signature pages thereto, and PNC Bank, National Association, as Administrator, and as LC Bank, incorporated by reference to Exhibit 10.2 of Form 10-Q (file no. 001-14901) for the quarter ended March 31, 2014, filed on May 6, 2014.
10.17	Eleventh Amendment to Amended and Restated Receivables Purchase Agreement, dated as of May 23, 2014, by and among CNX Funding Corporation, as seller, CONSOL Energy Inc., as the initial Servicer, the Sub-Servicers listed on the signature pages thereto, the Conduit Purchasers listed on the signature pages thereto, the Purchaser Agents listed on the signature pages thereto, the LC Participants listed on the signature pages thereto, and PNC Bank, National Association, as Administrator, and as LC Bank, incorporated by reference to Exhibit 10.2 of Form 10-Q (file no. 001-14901) filed on May 5, 2015..
10.18	Twelfth Amendment to Amended and Restated Receivables Purchase Agreement, dated as of March 27, 2015, by and among CNX Funding Corporation, as seller, CONSOL Energy Inc., as the initial Servicer, the Sub-Servicers listed on the signature pages thereto, the Conduit Purchasers listed on the signature pages thereto, the Purchaser Agents listed on the signature pages thereto, the LC Participants listed on the signature pages thereto, and PNC Bank, National Association, as Administrator, and as LC Bank, incorporated by reference to Exhibit 10.3 of Form 10-Q (file no. 001-14901) filed on May 5, 2015..
10.19	Letter Agreement re: Receivables Purchase Agreement - Dilution Ratio, dated June 21, 2012, incorporated by reference to Exhibit 10.1 to Form 10-Q for the quarter ended June 30, 2012 (file no. 001-14901), filed on August 1, 2012.
10.20	Letter Agreement Re: Receivables Purchase Agreement - Delinquency Ratio and Default Ratio, dated April 18, 2014, incorporated by reference to Exhibit 10.1 of Form 10-Q (file no. 001-14901) filed on May 5, 2015.
10.21	Payoff and Termination Letter re: Amended and Restated Receivables Purchase Agreement, dated as of July 7, 2015, by and among CNX Funding Corporation, as seller, CONSOL Energy Inc., as the Servicer, the Sub-Servicers listed on the signature pages thereto, the Conduit Purchasers listed on the signature pages thereto, the Purchaser Agents listed on the signature pages thereto, the LC Participants listed on the signature pages thereto, and PNC Bank, National Association, as Administrator, and as LC Bank, incorporated by reference to Exhibit 10.2 of Form 10-Q (file no. 001-14901) filed on July 31, 2015.
10.22	Commitment Letter, dated March 14, 2010, among Banc of America Bridge LLC, Banc of America Securities LLC, PNC Bank, National Association PNC Capital Markets LLC and CONSOL Energy Inc., incorporated by reference to Exhibit 10.2 to Form 8-K (file no. 001-14901) filed on March 16, 2010.
10.23	Share Tender Agreement, dated as of March 21, 2010, by and between CONSOL Energy Inc., and T. Rowe Price Associates, Inc., incorporated by reference to Exhibit 10.1 to Form 8-K (file no. 001-14901) filed on

	March 22, 2010 (Film No. 10695706).
10.24	Amended and Restated Credit Agreement, dated as of April 12, 2011, by and among CONSOL Energy Inc., the Guarantors Party thereto, the Lenders Party thereto, PNC Bank, National Association, as the Administrative Agent, Bank of America, N.A., as the Syndication Agent, The Bank of Nova Scotia, The Royal Bank of Scotland PLC and Sovereign Bank, as the Co-Documentation Agents, and PNC Capital Markets LLC and Merrill Lynch, Pierce, Fenner & Smith Incorporated, as Joint Lead Arrangers, incorporated by reference to Exhibit 10.1 to Form 8-K (file no. 001-14901) filed on April 18, 2011.
10.25	Amendment No. 1 to Credit Agreement, dated as of December 5, 2013, to the Amended and Restated Credit Agreement, dated as of April 12, 2011, by and among CONSOL Energy Inc., the lenders and agents party thereto and PNC Bank, National Association, as administrative agent, incorporated by reference to Exhibit 10.1 to Form 8-K (file no. 001-14901) filed on December 11, 2013.
10.26	Amended and Restated Credit Agreement, dated as of June 18, 2014, by and among CONSOL Energy Inc., the lenders and agents party thereto and PNC Bank, National Association, as administrative agent, incorporated by reference to Exhibit 10.1 to Form 8-K/A (file no. 001-14901) filed on June 25, 2014.

10.27	Amendment No. 1, dated as of May 22, 2015, to the Amended and Restated Credit Agreement, dated as of June 18, 2014, by and among CONSOL Energy Inc., the subsidiary guarantors party thereto and certain lenders and PNC Bank, National Association as administrative agent, incorporated by reference to Exhibit 10.1 to Form 8-K (file no. 001-14901) filed on May 26, 2015.
10.28	Amended and Restated Collateral Trust Agreement, dated as of May 7, 2010, by and among CONSOL Energy Inc. and its Designated Subsidiaries, Wilmington Trust Company, as Corporate Trustee and David A. Vanaskey, as Individual Trustee, incorporated by reference to Exhibit 2.2 to Form 8-K (file no. 001-14901) filed on May 13, 2010.
10.29	Amended and Restated Pledge Agreement, dated as of May 7, 2010, made and entered into by each of the pledgors listed on the signature pages thereto and each other persons and entities that become bound thereto from time to time by joinder, assumption, or otherwise and Wilmington Trust Company, as Collateral Trustee, incorporated by reference to Exhibit 2.3 to Form 8-K (file no. 001-14901) filed on May 13, 2010.
10.30	Amended and Restated Security Agreement, dated as of May 7, 2010, by and among CONSOL Energy Inc., each of the parties listed on the signature pages thereto and each other persons and entities that become bound thereto from time to time by joinder, assumption, or otherwise and Wilmington Trust Company, as Collateral Trustee, incorporated by reference to Exhibit 2.4 to Form 8-K (file no. 001-14901) filed on May 13, 2010.
10.31	Patent, Trademark and Copyright Security Agreement, dated as of June 27, 2007, by and among each of the pledgors listed on the signature pages thereto and each of the other persons and entities that become bound thereby from time to time by joinder, assumption, or otherwise and Wilmington Trust Company, as Collateral Trustee, incorporated by reference to Exhibit 10.20 to Form 10-K for the year ended December 31, 2010 (file no. 001-14901), filed on February 10, 2011.
10.32	First Amendment to Amended and Restated Patent, Trademark and Copyright Security Agreement, dated as of May 7, 2010, by and among each of the pledgors listed on the signature pages thereto and each other persons and entities that become bound thereto from time to time by joinder, assumption, or otherwise and Wilmington Trust Company, as Collateral Trustee, incorporated by reference to Exhibit 2.5 to Form 8-K (file no. 001-14901) filed on May 13, 2010.
10.33	Patent, Trademark and Copyright Assignment and Assumption, dated as of April 12, 2011, between Wilmington Trust Company as assignor and PNC Bank, National Association as assignee, incorporated by reference to Exhibit 2.1 to Form 8-K (file no. 001-14901) filed on April 18, 2011.
10.34	Guaranty and Suretyship Agreement, dated as of April 30, 2003, by CONSOL Energy Inc., as guarantor in favor of CNX Funding Corporation, incorporated by reference to Exhibit 10.6 to Form 10-Q (file no. 001-14901) for the quarter ended March 31, 2011, filed on May 3, 2011.
10.35	Amended and Restated Continuing Agreement of Guaranty and Suretyship, dated as of May 7, 2010, jointly and severally given by each of the undersigned thereto and each of the other persons which become Guarantors thereunder from time to time in favor of PNC Bank, National Association, in its capacity as the administrative agent for the Lenders, in connection with that certain Amended and Restated Credit Agreement, as defined therein, incorporated by reference to Exhibit 10.22 to Form 10-K for the year ended December 31, 2010 (file no. 001-14901), filed on February 10, 2011.
10.36	CNX Gas Continuing Agreement of Guaranty and Suretyship, dated as of April 12, 2011, by CNX Gas Corporation and certain of its subsidiaries, incorporated by reference to Exhibit 10.2 to Form 8-K (file no. 001-14901) filed on April 18, 2011.
10.37	Successor Agent Agreement, dated as of April 12, 2011, by and among among Wilmington Trust Company and David A. Varansky as existing agents, PNC Bank, National Association as Collateral Trustee and CONSOL Energy Inc. and certain of its subsidiaries, incorporated by reference to Exhibit 2.2 to Form 8-K (file no. 001-14901) filed on April 18, 2011.
10.38	Amended and Restated Credit Agreement, dated as of April 12, 2011, by and among CNX Gas Corporation, the Guarantors Party thereto, the Lenders Party thereto, PNC Bank, National Association, as the Administrative Agent, Bank of America, N.A., as the Syndication Agent, The Bank of Nova Scotia, The

	Royal Bank of Scotland PLC and Wells Fargo Bank, N.A., as the Co-Documentation Agents, and PNC Capital Markets LLC and Merrill Lynch, Pierce, Fenner & Smith Incorporated, as Bookrunners and Joint Lead Arrangers, incorporated by reference to Exhibit 10.3 to Form 8-K (file no. 001-14901) filed on April 18, 2011.
10.39	Amendment No. 1 to Credit Agreement, dated as of December 14, 2011, by and among CNX Gas Corporation, the lenders and agents party thereto and PNC Bank, National Association, as Administrative Agent, incorporated by reference to Exhibit 10.29 to Form 10-K for the year ended December 31, 2012 (file no. 01-14901), filed on February 7, 2013.
10.40	Amendment No. 2 to Credit Agreement, dated as of March 12, 2013, to the Amended and Restated Credit Agreement, dated as of April 12, 2011, as amended by Amendment No. 1, dated December 14, 2011, by and among CNX Gas Corporation, the lenders and agents party thereto and PNC Bank, National Association, as administrative agent, incorporated by reference to Exhibit 10.1 of Form 10-Q (file no. 001-14901) for the quarter ended March 31, 2013, filed on May 7, 2013.
10.41	Collateral Trust Agreement, dated as of May 7, 2010, by and among CNX Gas Corporation, its Designated Subsidiaries, Wilmington Trust Company, as Corporate Trustee and David A. Vanaskey, as Individual Trustee, incorporated by reference to Exhibit 2.1 to the CNX Gas Corporation Form 8-K (file no. 001-32723) filed on May 13, 2010.

10.42	Pledge Agreement, dated as of May 7, 2010, by each of the pledgors listed on the signature pages thereto and each of the other persons and entities that become bound thereby from time to time by joinder, assumption or otherwise and Wilmington Trust Company, as Collateral Trustee, incorporated by reference to Exhibit 2.2 to the CNX Gas Corporation Form 8-K (file no. 001-32723) filed on May 13, 2010.
10.43	Security Agreement, dated as of May 7, 2010, by and among CNX Gas Corporation and each of the undersigned parties thereto and each of the other persons and entities that become bound thereby from time to time by joinder, assumption or otherwise and Wilmington Trust Company, as Collateral Trustee, incorporated by reference to Exhibit 2.3 to the CNX Gas Corporation Form 8-K (file no. 001-32723) filed on May 13, 2010.
10.44	CONSOL Amended and Restated Continuing Agreement of Guaranty and Suretyship, dated as of April 12, 2011, by CONSOL Energy and certain of its subsidiaries, incorporated by reference to Exhibit 10.4 to Form 8-K (file no. 001-14901) filed on April 18, 2011.
10.45	Amended and Restated Continuing Agreement of Guaranty and Suretyship, dated as of April 12, 2011, among CNX Gas Company LLC and certain of its subsidiaries, incorporated by reference to Exhibit 10.5 to Form 8-K (file no. 001-14901) filed on April 18, 2011.
10.46	Successor Agent Agreement, dated as of April 12, 2011, by and among Wilmington Trust Company and David A. Vanaskey as existing agents, PNC Bank, National Association as Collateral Trustee and CNX Gas Corporation and certain of its subsidiaries, incorporated by reference to Exhibit 2.3 to Form 8-K (file no. 001-14901) filed on April 18, 2011.
10.47	Closing Agreement by and between CNX Gas Company LLC and Noble Energy, Inc. dated as of September 30, 2011, incorporated by reference to Exhibit 10.2 to Form 10-Q (file no. 001-14901) for the quarter ended September 30, 2011, filed on October 31, 2011.
10.48	Stipulation and Agreement of Compromise and Settlement, dated May 8, 2013, between and among (i) plaintiffs Harold L. Hurwitz and James R. Gummel, on their own behalf and on behalf of the Class (as defined therein) and (ii) defendants CNX Gas Corporation, CONSOL Energy Inc. and certain individual defendants, incorporated by reference to Exhibit 10.1 of Form 10-Q (file no. 001-14901) for the quarter ended June 30, 2013, filed on August 5, 2013.
10.49	Amendment No. 1, dated April 19, 2013, to the Asset Acquisition Agreement, dated August 17, 2011, between CNX Gas Company LLC and Noble Energy, Inc, incorporated by reference to Exhibit 10.2 of Form 10-Q (file no. 001-14901) for the quarter ended June 30, 2013, filed on August 5, 2013.
10.50	Purchase Agreement, dated as of April 10, 2014, among CONSOL Energy Inc., the subsidiary guarantors party thereto and J.P. Morgan Securities LLC and Credit Suisse Securities (USA) LLC, as representatives of the several initial purchasers named therein, incorporated by reference to Exhibit 1.1 to Form 8-K (file no. 001-14901) filed on April 16, 2014.
10.51*	Time Sharing Agreement, dated as of May 1, 2007, by and between CONSOL Energy Inc. and J. Brett Harvey, incorporated by reference to Exhibit 10.1 to Form 8-K (file no. 001-14901) filed on May 7, 2007.
10.52*	Amended and Restated Employment Agreement, dated March 21, 2014, between CONSOL Energy Inc. and J. Brett Harvey incorporated by reference to Exhibit 10.1 to Form 8-K (file no. 001-14901) filed on March 26, 2014.
10.53*	Letter Agreement, dated August 24, 2007, by and between CONSOL Energy Inc. and Nicholas J. DeIuliis, incorporated by reference to Exhibit 10.1 to Form 8-K (file no. 001-14901) filed on August 24, 2007.
10.54*	Change in Control Agreement by and between CONSOL Energy Inc. and J. Brett Harvey, incorporated by reference to Exhibit 10.3 to Form 10-K for the year ended December 31, 2008 (file no. 001-14901), filed on February 17, 2009.
10.55*	Change in Control Agreement by and between CONSOL Energy Inc. and Nicholas J. DeIuliis, incorporated by reference to Exhibit 10.7 to Form 10-K for the year ended December 31, 2008 (file no. 001-14901), filed on February 17, 2009.
10.56*	Amended and Restated Change in Control Severance Agreement, dated as of April 10, 2014, between CONSOL Energy Inc. and David M. Khani, incorporated by reference to Exhibit 10.8 to Form 10-Q (file no.

	001-14901) for the quarter ended March 31, 2014, filed on May 6, 2014.
10.57*	Amended and Restated Change in Control Severance Agreement, dated as of October 9, 2015, between CONSOL Energy Inc., and David M. Khani, incorporated by reference to Exhibit 10.1 to Form 10-Q (file no. 001-14901) for the quarter ended September 30, 2015, filed on November 3, 2015.
10.58*	Amended and Restated Change in Control Severance Agreement, dated as of April 10, 2014, between CONSOL Energy Inc. and James Grech, incorporated by reference to Exhibit 10.9 to Form 10-Q (file no. 001-14901) for the quarter ended March 31, 2014, filed on May 6, 2014.
10.59*	Change in Control Agreement by and among CNX Gas Corporation, CONSOL Energy Inc. and Stephen W. Johnson, incorporated by reference to Exhibit 10.4 to Form 10-K for the year ended December 31, 2008 of CNX Gas Corporation (file no. 001-32723) filed on February 17, 2009.
10.60*	Amended and Restated Change in Control Severance Agreement, dated as of April 10, 2014, between CONSOL Energy Inc. and James A. Brock, incorporated by reference to Exhibit 10.54 to Form 10-K for the year ended December 31, 2014 (file no. 001-14901), filed on February 6, 2015.

10.61*	Amended and Restated Change in Control Severance Agreement, dated as of August 24, 2015, between CONSOL Energy Inc., and James A. Brock, incorporated by reference to Exhibit 10.3 to Form 10-Q (file no. 001-14901) for the quarter ended September 30, 2015, filed on November 3, 2015.
10.62*	Change in Control Severance Agreement, dated as of February 28, 2014, between CONSOL Energy Inc. and Timothy Dugan, incorporated by reference to Exhibit 10.55 to Form 10-K for the year ended December 31, 2014 (file no. 001-14901), filed on February 6, 2015.
10.63*	Amended and Restated Change in Control Severance Agreement, dated as of August 24, 2015, between CONSOL Energy Inc., and Timothy Dugan, incorporated by reference to Exhibit 10.3 to Form 10-Q (file no. 001-14901) for the quarter ended September 30, 2015, filed on November 3, 2015.
10.64*	Form of Indemnification Agreement for Directors and Executive Officers of CONSOL Energy Inc., incorporated by reference to Exhibit 10.6 to Form 10-Q (file no. 001-14901) for the quarter ended June 30, 2009, filed on August 3, 2009.
10.65*	Form of Indemnification Agreement for Directors and Executive Officers of CNX Gas Corporation, incorporated by reference to Exhibit 10.7 to Form 10-Q (file no. 001-14901) for the quarter ended June 30, 2009, filed on August 3, 2009.
10.66*	Equity Incentive Plan, As Amended and Restated, effective May 1, 2012 incorporated by reference to Exhibit 10.1 to the Form 8-K (file no. 001-14901) filed on March 21, 2012.
10.67*	Amended and Restated CONSOL Energy Inc. Executive Annual Incentive Plan, incorporated by reference to Appendix A to the Form DEF 14A (file no. 001-14901) filed on March 29, 2013.
10.68*	Non-Employee Director Option Grant Notice, as amended, incorporated by reference to Exhibit 10.84 to the Form 8-K (file no. 001-14901) filed on October 24, 2005.
10.69*	Form of Non-Qualified Stock Option Award Agreement For Employees, incorporated by reference to Exhibit 10.26 to the Registration Statement on Form S-4 (file no. 333-149442) filed on February 28, 2008.
10.70*	Form of Non-Qualified Stock Option Award Agreement for Employees (February 17, 2009 and through 2012), incorporated by reference to Exhibit 10.28 to Form S-4 (file no. 333-157894) filed on June 26, 2009.
10.71*	Form of Non-Qualified Performance Stock Option Agreement for employees, incorporated by reference to Exhibit 10.1 to Form 8-K (file no. 001-14901) filed on June 21, 2010.
10.72*	Form of Non-Qualified Stock Option Award for Employees (January 27, 2016 and after).
10.73*	Form of Restricted Stock Unit Award for Employees (February 17, 2009 through 2014), incorporated by reference to Exhibit 10.31 to Amendment No. 1 to Form S-4 (file no. 333-157894) filed on June 26, 2009.
10.74*	Form of 5-Year Restricted Stock Unit Award Agreement for Employees, incorporated by reference to Exhibit 10.4 to Form 10-Q (file no. 001-14901) for the quarter ended March 31, 2014, filed on May 6, 2014.
10.75*	Form of Restricted Stock Unit Award Agreement for Directors, incorporated by reference to Exhibit 10.30 to the Registration Statement on Form S-4 (file no. 333-149442) filed on February 28, 2008.
10.76*	Form of Restricted Stock Unit Award Agreement for Employees (for 2015 awards), incorporated by reference to Exhibit 10.67 to Form 10-K for the year ended December 31, 2014 (file no. 001-14901), filed on February 6, 2015.
10.77*	Form of Performance Share Unit Award Agreement (for 2014 awards), incorporated by reference to Exhibit 10.3 to Form 10-Q (file no. 001-14901) for the quarter ended March 31, 2014, filed on May 6, 2014.
10.78*	Form of Performance Share Unit Award Agreement (for 2015 awards and after), incorporated by reference to Exhibit 10.69 to Form 10-K for the year ended December 31, 2014 (file no. 001-14901), filed on February 6, 2015.
10.79*	Form of Performance Share Unit Award Agreement (for 2016 awards and after).
10.80*	Form of CONSOL Stock Unit Acknowledgment Letter, incorporated by reference to Exhibit 10.5 to Form 10-Q (file no. 001-14901) for the quarter ended March 31, 2014, filed on May 6, 2014.
10.81*	Form of CONSOL Stock Unit Acknowledgment Letter (Alternate), incorporated by reference to Exhibit 10.6 to Form 10-Q (file no. 001-14901) for the quarter ended March 31, 2014, filed on May 6, 2014.
10.82*	Form of CONSOL Stock Unit Award Agreement under the Equity Incentive Plan, incorporated by reference to Exhibit 10.2 to Form 10-Q (file no. 001-14901) for the quarter ended March 31, 2013, filed on May 7,

	2013.
10.84*	Summary of Non-Employee Director Compensation, incorporated by reference to Exhibit 10.69 to Form 10-K (file no. 001-14901) for the year ended December 31, 2013, filed on February 7, 2014.
10.85*	Directors Deferred Compensation Plan (1999 Plan), incorporated by reference to Exhibit 10.1 to Form 10-Q (file no. 001-14901) for the quarter ended March 31, 2008, filed on April 30, 2008.
10.86*	Directors' Deferred Fee Plan (2004 Plan) (Amended and Restated on December 4, 2007), incorporated by reference to Exhibit 10.3 to Form 10-Q (file no. 001-14901) for the quarter ended March 31, 2008, filed on April 30, 2008.
10.87*	Hypothetical Investment Election Form Relating to Directors' Deferred Fee Plan (2004 Plan), incorporated by reference to Exhibit 10.50 to Form 10-K for the year ended December 31, 2007 (file no. 001-14901), filed on February 19, 2008.

10.88*	Form of Director Deferred Stock Unit Grant Agreement, incorporated by reference to Exhibit 10.95 to the Form 8-K (file no. 001-14901) filed on May 8, 2006.
10.89*	Trust Agreement (Amended and Restated on March 20, 2008) (1999 Directors Deferred Compensation Plan), incorporated by reference to Exhibit 10.2 to Form 10-Q (file no. 001-14901) for the quarter ended March 31, 2008, filed on April 30, 2008.
10.90*	Trust Agreement (Amended and Restated on March 20, 2008) (Directors' Deferred Fee Plan (2004 Plan)), incorporated by reference to Exhibit 10.4 to Form 10-Q (file no. 001-14901) for the quarter ended March 31, 2008, filed on April 30, 2008.
10.91*	Amended and Restated Retirement Restoration Plan of CONSOL Energy Inc., incorporated reference to Exhibit 10.30 to Form 10-K for the year ended December 31, 2008 (file no. 001-14901), filed on February 17, 2009.
10.92*	Amended and Restated Supplemental Retirement Plan of CONSOL Energy Inc. effective January 1, 2007, as amended and restated on September 8, 2009, incorporated by reference to Exhibit 10.1 to Form 8-K (file no. 001-14901) filed on September 11, 2009.
10.93*	Amendment to CONSOL Energy Inc. Supplemental Retirement Plan, dated as of October 17, 2011, incorporated by reference to Exhibit 10.3 to Form 10-Q (file no. 001-14901), for the quarter ended September 30, 2011, filed on October 31, 2011.
10.94*	CONSOL Energy Inc. Defined Contribution Restoration Plan, effective January 1, 2012, incorporated by reference to Exhibit 10.12 of Form 10-Q (file no. 001-14901) for the quarter ended March 31, 2014, filed on May 6, 2014.
10.95*	Executive Compensation Clawback Policy of CONSOL Energy Inc., dated as of January 28, 2014, incorporated by reference to Exhibit 10.11 of Form 10-Q (file no. 001-14901) for the quarter ended March 31, 2014, filed on May 6, 2014.
12	Computation of Ratio of Earnings to Fixed Charges.
14.1	Code of Employee Business Conduct and Ethics
21	Subsidiaries of CONSOL Energy Inc.
23.1	Consent of Ernst & Young LLP
23.2	Consent of Netherland Sewell & Associates, Inc.
31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
95	Mine Safety Disclosure Exhibit
99	Engineers' Audit Letter
101	Interactive Data File (Form 10-K for the year ended December 31, 2015 furnished in XBRL).

* Denotes the management contracts and compensatory arrangements in which any director or any named executive officer participates

Supplemental Information

No annual report or proxy material has been sent to shareholders of CONSOL Energy at the time of filing of this Form 10-K. An annual report will be sent to shareholders and to the commission subsequent to the filing of this Form 10-K. In accordance with SEC Release 33-8238, Exhibits 32.1 and 32.2 are being furnished and not filed.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, as of the 5th day of February, 2016.

CONSOL ENERGY INC.

By: /s/ NICHOLAS J. DEIULIIS
Nicholas J. DeIuliis
Director, Chief Executive Officer and President
(Duly Authorized Officer and Principal Executive Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed as of the 5th day of February, 2016, by the following persons on behalf of the registrant in the capacities indicated:

Signature	Title
/s/ NICHOLAS J. DEIULIIS Nicholas J. DeIuliis	Director, Chief Executive Officer and President (Duly Authorized Officer and Principal Executive Officer)
/s/ DAVID M. KHANI David M. Khani	Chief Financial Officer and Executive Vice President (Duly Authorized Officer and Principal Financial Officer)
/s/ C. KRISTOPHER HAGEDORN C. Kristopher Hagedorn	Controller and Vice President (Duly Authorized Officer and Principal Accounting Officer)
/s/ J. BRETT HARVEY J. Brett Harvey	Director and Chairman of the Board
/s/ PHILIP W. BAXTER Philip W. Baxter	Lead Independent Director
/s/ ALVIN R. CARPENTER Alvin R. Carpenter	Director
/s/ WILLIAM E. DAVIS William E. Davis	Director
/s/ DAVID C. HARDESTY, JR. David C. Hardesty, Jr.	Director
/s/ MAUREEN E. LALLY-GREEN Maureen E. Lally-Green	Director
/s/ GREGORY A. LANHAM Gregory A. Lanham	Director
/s/ JOHN T. MILLS John T. Mills	Director

/s/ WILLIAM P. POWELL William P. Powell	Director
/s/ WILLIAM N. THORNDIKE William N. Thorndike	Director

SCHEDULE II

CONSOL ENERGY INC. AND SUBSIDIARIES
Valuation and Qualifying Accounts
(Dollars in thousands)

	Balance at Beginning of Period	Additions Charged to Expense	Deductions Release of Valuation Allowance	Charged to Expense	Balance at End of Period
Year Ended December 31, 2015					
State operating loss carry-forwards	$6,080	$31,578	$5,325	$—	$42,983
Deferred deductible temporary differences	16	7,914	1,490	—	9,420
Foreign Tax Credits	—	25,903	—	—	25,903
Total	$6,096	$65,395	$6,815	$—	$78,306
Year Ended December 31, 2014					
State operating loss carry-forwards	$7,527	$157	$(1,323)	$(281)	$6,080
Deferred deductible temporary differences	5	11	—	—	16
Total	$7,532	$168	$(1,323)	$(281)	$6,096
Year Ended December 31, 2013					
State operating loss carry-forwards	$7,793	$1,987	$(1,410)	$(843)	$7,527
Deferred deductible temporary differences	170	—	—	(165)	5
Total	$7,963	$1,987	$(1,410)	$(1,008)	$7,532