CONSOL Energy Inc
Form 10-K
February 08, 2017

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, 2016
OR
o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to
Commission file number: 001-14901

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

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

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

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

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

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes x No o
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes o No x
Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No o
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No o
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of “large accelerated filer,” “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act. (Check one):
Large accelerated filer x Accelerated filer o Non-accelerated filer o Smaller Reporting Company o
Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
Yes o No x
The aggregate market value of voting stock held by nonaffiliates of the registrant as of June 30, 2016, 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 $1,829,987,445.
The number of shares outstanding of the registrant's common stock as of January 20, 2017 is 229,443,008 shares.
DOCUMENTS INCORPORATED BY REFERENCE:
Portions of CONSOL Energy's Proxy Statement for the Annual Meeting of Shareholders to be held on May 9, 2017, 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 TERMS

The following are certain terms and abbreviations 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 - those hydrocarbons in natural gas that are separated from the gas as liquids through the proces.
net - “net” natural gas or “net” acres are determined by adding the fractional ownership working interests the Company has in gross wells or acres.
proved reserves - quantities of oil, natural gas, and NGLs which, by analysis of geological and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation.
proved developed reserves - proved reserves which can be expected to be recovered through existing wells with existing equipment and operating methods.
proved undeveloped reserves (PUDs) - proved reserves that can be estimated with reasonable certainty to be recovered from new wells on undrilled proved acreage or from existing wells where a relatively major expenditure is required for completion.
reservoir - a porous and permeable underground formation containing a natural accumulation of producible natural gas and/or oil that is confined by impermeable rock or water barriers and is separate from other reservoirs.
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 and natural gas liquids 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 coal mining and natural gas operations;
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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;
- divestitures and acquisitions we anticipate may not occur or produce anticipated benefits;
- joint ventures that we are party to now or in the future may restrict our flexibility, actions taken by our joint ventures may impact our financial position and operational results;
- 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 near-term 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 coal sales contracts may provide limited protection during adverse economic conditions, and may result in economic penalties or permit the customer to terminate the contract;
- the majority of 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;
- with respect to the sale of the Buchanan and Amonate mines and other coal assets to Coronado IV LLC, any disruption to our business, including customer, employee and supplier relationships resulting from this transaction, and the impact of the transaction on our future operating results;
- there is no assurance that the potential drop-downs,spin-off or sale of the coal business will occur, or if it does occur that we will be able to negotiate favorable terms;
- with respect to the termination of the joint venture with NOBLE, any disruption to our business, including customer and supplier relationships from this transaction, and the impact of the transaction on our future operating and financial results and liquidity; and
- other factors discussed in this 2016 Form 10-K under “Risk Factors,” as updated by any subsequent Forms 10-Q, 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 natural gas exploration and production (E&P) and Pennsylvania (PA) Mining Operations. 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 PA Mining Operations 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 617% to produce 394.4 net Bcfe in 2016. This business has grown from coalbed methane production in Virginia into other unconventional production, including hydraulic fracturing in 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.

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 413,000 net acres in the Marcellus Shale and approximately 683,000 net acres that have Utica Shale potential in Ohio, West Virginia, and Pennsylvania. We also have approximately 2.2 million net acres in our coalbed methane play.

Highlights of our 2016 production include the following:
- Total average production of 1,080,512 Mcfe per day, an increase of 20% over 2015;
- 88% Natural Gas, 12% Liquids; and
- 54% Marcellus, 23% Utica, 17% coalbed methane, and 6% other.

At December 31, 2016, our proved natural gas, NGL, condensate and oil reserves (collectively, "natural gas reserves") had the following characteristics:
- 6.3 Tcfe of proved reserves;
- 93.2% natural gas;
- 58.9% proved developed;
- 87.6% operated; and
- A reserve life ratio of 15.85 years (based on 2016 production).

Highlights of coal activities in 2016 include the following:
- Production of 24.6 million tons of coal;

- Coal reserve holdings of 2.4 billion tons; and
- 75% of coal sales to domestic utilities.

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 E&P 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 coal markets. Ultimately, we intend to separate our E&P division and our PA Mining Operations 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. With the recent growth of natural gas exports to Mexico and Canada and the United States becoming a net exporter of natural gas in 2016, we expect new markets to open up in the coming years. We feel that our significant increases in natural gas production, our reductions in drilling and operating costs and our vast acreage position will allow CONSOL Energy to take advantage of these markets.

CONSOL Energy’s coal assets align with the PA Mining Operations division's long-term strategic objectives. The production, 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.

These mines, along with our 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.

CONSOL Energy's E&P Capital Expenditure Budget

In 2017, the E&P division expects capital expenditures of approximately $555 million. The E&P division capital expenditures are comprised of the following: $465 million for drilling and completion activity; $40 million for midstream, including capital contributions to CONE Midstream Partners, LP; and $50 million for other activities related to land, permitting, and business development.

DETAIL E&P OPERATIONS

Our E&P 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 413,000 net Marcellus Shale acres at December 31, 2016.

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; these acres have not been disclosed separately as they coincide with our Marcellus acreage.

In December 2016, CONSOL Energy terminated the 50-50 Joint Venture that was formed in 2011, with Noble Energy, Inc., for the exploration, development, and operation of primarily Marcellus Shale properties in Pennsylvania and West Virginia. As a result of the termination, each party now owns and operates a 100% interest in its properties and wells in two separate operating areas; and each party will now have independent control and flexibility with respect to the scope and timing of future development over its operating area.

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. See "Midstream Gas Services" for a more detailed explanation.

Utica Shale

We have the rights to extract natural gas in Pennsylvania, West Virginia, and Ohio from approximately 683,000 net Utica Shale acres at December 31, 2016. Approximately 305,000 Utica acres coincide with Marcellus Shale acreage in Pennsylvania, West Virginia, and Ohio.

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 CBM natural gas primarily from the Pocahontas #3 seam.

We also have the rights to extract CBM in West Virginia, southwestern Pennsylvania, and Ohio from approximately 912,000 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 584,000 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 in New Mexico. We have no plans to drill CBM wells in these areas in 2017.

Other Gas

Shallow Oil and Gas

We have the rights to extract natural gas from shallow oil and gas positions in Illinois, Indiana, Kentucky, Pennsylvania, West Virginia, Virginia and New York from approximately 766,000 net acres at December 31, 2016. 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.

Chattanooga

We have the rights to extract natural gas in Tennessee from approximately 95,000 net Chattanooga Shale acres at December 31, 2016.

Huron

We have approximately 503,000 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, 2016

	Marcellus Segment	Utica Segment	CBM Segment	Other Gas Segment	Total
Estimated Net Proved Reserves (MMcfe)	3,137,336	1,371,978	1,254,633	487,701	6,251,648
Percent Developed	60 %	28 %	75 %	100 %	59 %
Net Producing Wells (including oil and gob wells)	283	54	4,359	8,180	12,876
Net Acreage Position:					
Net Proved Developed Acres	30,737	9,649	257,019	243,877	541,282
Net Proved Undeveloped Acres	11,763	12,836	5,439	—	30,038
Net Unproved Acres(1)	370,263	355,332	1,900,260	1,119,678	3,745,533
Total Net Acres(2)	412,763	377,817	2,162,718	1,363,555	4,316,853

(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 only included under the target strata CONSOL Energy expects to produce with the exception of certain CBM acres governed by separate leases, although the reported acres may include rights to multiple gas seams (e.g. we have rights to Marcellus segment that are disclosed under the Utica segment and we have rights to Utica segment that are disclosed under the Marcellus segment). We have reviewed our drilling plans, our acreage rights and used our best judgment to reflect the acres in the strata we expect to primarily 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, 2016, the number of producing wells, developed acreage and undeveloped acreage:

	Gross	Net(1)
Producing Gas Wells (including gob wells)	17,314	12,846
Producing Oil Wells	189	30
Net Acreage Position:		
Proved Developed Acreage	549,816	541,282
Proved Undeveloped Acreage	34,467	30,038
Unproved Acreage	4,804,804	3,745,533
Total Acreage	5,389,087	4,316,853

(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	3,644,799	13,967
Expiration within 2 years	68,084	9,347
Expiration beyond 2 years	32,650	6,724
Total Acreage	3,745,533	30,038

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 approximately 2% of our total acres in the above categories and leases with expiration dates beyond two years represent approximately 1% 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, 2016, 2015 and 2014, we drilled 36.0, 132.8 and 180.3 net development wells, respectively. Gob wells and wells drilled by operators other than our primary joint venture partners at that time, Noble Energy and Hess Corporation, are excluded from net development wells. In 2016, there were 68 gross development wells drilled but uncompleted. There were no dry development wells in 2016, 2015, or 2014. As of December 31, 2016, there are 3.0 gross completed developmental wells ready to be turned in-line. The following table illustrates the net wells drilled by well classification type:

	For the Year Ended December 31,		
	2016	2015	2014
Marcellus segment	—	44.0	84.0
Utica segment	13.0	15.8	18.8
CBM segment	23.0	73.0	75.0
Other Gas segment	—	—	2.5
Total Development Wells (Net)	36.0	132.8	180.3

Exploratory Wells (Net)

There were no exploratory wells drilled during the year ended December 31, 2016. During the years ended December 31, 2015 and 2014, we drilled, in the aggregate, 2.5, and 8.5 net exploratory wells, respectively. As of December 31, 2016, 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,								
	2016			2015			2014		
	Producing	Dry	Still Eval.	Producing	Dry	Still Eval.	Producing	Dry	Still Eval.
Marcellus segment	—	—	—	—	—	—	1.5	—	—
Utica segment	—	—	—	2.5	—	—	1.0	—	—
CBM segment	—	—	—	—	—	—	—	—	—
Other Gas segment	—	—	—	—	—	—	6.0	—	—
Total Exploratory Wells (Net)	—	—	—	2.5	—	—	8.5	—	—

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,		
	2016	2015	2014
Proved developed reserves	3,683,302	3,697,152	3,198,706
Proved undeveloped reserves	2,568,346	1,945,837	3,628,910
Total proved developed and undeveloped reserves(1)	6,251,648	5,642,989	6,827,616

(1) 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)		
	2016	2015	2014
Future net cash flows	$2,419	$2,499	$9,321
Total PV-10 measure of pre-tax discounted future net cash flows (1)	$1,559	$1,659	$4,884
Total standardized measure of after tax discounted future net cash flows	$955	$1,019	$2,984

(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,		
	2016	2015	2014
	(Dollars in millions)		
Future cash inflows	$11,303	$11,838	$28,503
Future production costs	(5,851)	(6,585)	(10,101)
Future development costs (including abandonments)	(1,550)	(1,220)	(3,369)
Future net cash flows (pre-tax)	3,902	4,033	15,033
10% discount factor	(2,343)	(2,374)	(10,149)
PV-10 (Non-GAAP measure)	1,559	1,659	4,884
Undiscounted income taxes	(1,483)	(1,534)	(5,712)
10% discount factor	879	894	3,812
Discounted income taxes	(604)	(640)	(1,900)
Standardized GAAP measure	$955	$1,019	$2,984

Gas Production

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

	For the Year Ended December 31,		
	2016	2015	2014
GAS			
Marcellus Sales Volumes (MMcf)	186,812	145,747	99,370
Utica Sales Volumes (MMcf)	71,277	38,344	10,303
CBM Sales Volumes (MMcf)	68,971	74,910	79,459
Other Sales Volumes (MMcf)	21,693	28,286	27,128
LIQUIDS*			
NGLs Sales Volumes (MMcfe)	40,260	33,180	15,475
Oil Sales Volumes (MMcfe)	410	592	681
Condensate Sales Volumes (MMcfe)	4,964	7,598	3,298
TOTAL (MMcfe)	394,387	328,657	235,714

*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 2017 annual gas production to grow to approximately 415 Bcfe and increase to approximately 485 Bcfe in 2018.

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.

	For the Year Ended December 31,		
	2016	2015	2014
Average Sales Price - Gas (Mcf)	$1.92	$2.17	$4.02
Gain on Commodity Derivative Instruments - Cash Settlement- Gas (Mcf)	$0.70	$0.68	$0.11
Average Sales Price - NGLs (Mcfe)*	$2.42	$2.05	$5.95
Average Sales Price - Oil (Mcfe)*	$6.15	$7.99	$14.85
Average Sales Price - Condensate (Mcfe)*	$4.58	$4.42	$11.16
Total Average Sales Price (per Mcfe)	$2.63	$2.81	$4.37
Average Lifting Costs excluding ad valorem and severance taxes (per Mcfe)	$0.24	$0.37	$0.59

*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.

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 $0.09 per Mcfe, $0.05 per Mcfe, and $0.25 per Mcfe for 2016, 2015, and 2014, 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 264.9 Bcf of our produced gas sales volumes for the year ended December 31, 2016 at an average price of $3.04 per Mcf. The notional volumes associated with these gas swaps 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. As of January 17, 2017, we expect these transactions will represent approximately 311.3 Bcf of our estimated 2017 production at an average price of $2.61 per Mcf, 220.6 Bcf of our estimated 2018 production at an average price of $2.75 per Mcf, 161.7 Bcf of our estimated 2019 production at an average price of $2.76 per Mcf, approximately 85 Bcf of our estimated 2020 production at an average price of $2.91 per Mcf, and approximately 6.8 Bcf of our estimated 2021 production at an average price of $3.08 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 21 - 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 our Marcellus Shale position. On September 30, 2014, CONE Midstream Partners LP (the Partnership) closed its initial public offering. See Note 25 - Related Party Transactions in the Notes to Audited Consolidated Financial Statements in Item 8 of this Form 10-K for more information.

In the Utica Shale, we and our joint venture partner, Hess, primarily contract 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. 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 currently served by a large concentration of major pipelines that provide us with the capacity to move our production to the major gas markets, and it is expected that recently-approved pipeline projects will increase the take-away capacity from our region. 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 and Utica shale production. These types of gas can be complementary by reducing and in some cases eliminating the need for the costly processing of CBM. In addition, our lower Btu CBM and dry Marcellus and Utica production offer an opportunity to blend ethane back into the gas stream when pricing or capacity in ethane markets dictate. In developing a diversified approach to managing ethane, CONSOL Energy has entered into ethane supply agreements and is also discussing future outlet opportunities with ethane customers and midstream companies. These different gas types allow us more flexibility in bringing Marcellus and Utica shale wells on-line at qualities that meet interstate pipeline specifications.

Natural Gas Competition

The United States natural gas industry is highly competitive. CONSOL Energy competes with other large producers, as well as a myriad of smaller producers and marketers. CONSOL Energy also competes for pipeline and other services to deliver its products to customers. 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 during the first nine months of 2016. The EIA reported 554,201 producing natural gas wells in the United States at December 31, 2015 (the latest year for which government statistics are available), which is approximately two percent lower than 2014.

CONSOL Energy expects natural gas to be a significant contributor to the domestic electric generation mix in the long-term, as well as to fuel industrial growth in the U.S. economy. According to the EIA, based on preliminary results, natural gas represented 34% of U.S. electricity generation during 2016 compared with 33% in 2015. With the recent growth of natural gas exports to Mexico and Canada and increased liquefied natural gas exports, the U.S. became a net exporter of gas in 2016. CONSOL expects the high level of U.S. gas exports to continue in the future. In addition, there is potential for natural gas to become a significant contributor to the transportation market. 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, pipeline capacity, 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, 2016, CONSOL Energy had an estimated 2.4 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.

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 our mining complex. The amount of coal we assign to the 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 complex 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 mine because of the proximity of many of our mines to one another. In the table below, the accessible reserves indicated for a mine are based on our review of current mining plans and reflect our best judgment as to which mine 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.

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, 2016 and 2015

Mine/Reserve	Preparation Facility Location	Reserve Class	Coal Seam	Average Seam Thickness (feet)	As Received Heat Value(1) (Btu/lb) Typical	Range	Recoverable Reserves(2) Owned (%)	Leased (%)	Tons in Millions 12/31/2016	12/31/2015
ASSIGNED–OPERATING										
PA Mining Operations										
Bailey	Enon, PA	Assigned Operating	Pittsburgh	7.5	12,950	12,860 – 13,030	43%	57%	89.0	101.1
		Accessible	Pittsburgh	7.5	12,910	12,700 – 13,170	78%	22%	170.7	170.7
Harvey	Enon, PA	Assigned Operating	Pittsburgh	6.3	13,040	12,920 – 13,160	86%	14%	20.4	23.4
		Accessible	Pittsburgh	7.6	12,900	12,840 – 13,130	99%	1%	180.1	180.1
Enlow Fork	Enon, PA	Assigned Operating	Pittsburgh	7.8	12,980	12,820 – 13,190	99%	1%	31.2	10.9
		Accessible	Pittsburgh	7.6	13,040	12,780 – 13,180	76%	24%	275.3	305.3
Total Assigned Operating and Accessible									766.7	791.5

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(1) The heat values shown for Assigned Operating reserves are based on the 2016 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 the complex's preparation plant. Actual quality is based on laboratory analysis of samples collected from coal shipments delivered in 2016. 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. Reserves tons are reported on an as-received basis, based on the anticipated product moisture. 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, 2016 and 2015

Coal Producing Region	As Received Heat Value(1) (Btu/lb)	Recoverable Reserves(2) Owned (%)	Leased (%)	Tons in Millions 12/31/2016	Recoverable Reserves (Tons in Millions) 12/31/2015
Northern Appalachia (Pennsylvania, Ohio, Northern West Virginia) (3)	11,400 – 13,400	85%	15%	1,054.0	1,216.7
Central Appalachia (Virginia, Southern West Virginia)	12,400 – 14,100	77%	23%	157.2	322.2
Illinois Basin (Illinois, Western Kentucky, Indiana)	11,600 – 12,000	79%	21%	348.7	396.1
Total		83%	17%	1,559.9	1,935.0

(1) The heat value (gross calorific values) 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 heat value estimates for the Illinois Basin Unassigned reserves are based primarily on exploration drill core data that may not include adjustments for moisture added during mining or processing, or for dilution by rock lying above or below the coal seam.

(2) Recoverable reserves are calculated based on the area in which mineable coal exists, coal seam thickness, and average density determined by laboratory testing of drill core samples. This calculation is adjusted to account for coal that will not be recovered during mining and for losses that occur if the coal is processed after mining. Reserve calculations do not include adjustment for moisture that may be added during mining or processing, nor do the calculations include adjustments for dilution from rock lying above or below the coal seam. Reserves are 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, 2016

	≤ 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	—	—	—	—	—	39.6	—	—	—	39.6	1.7 %
Med Vol Bituminous	—	5.1	—	—	—	—	—	—	—	5.1	0.2 %
Low Vol Bituminous	—	—	16.0	—	—	26.3	—	—	—	42.3	1.8 %
Total Metallurgical	—	5.1	16.0	—	—	65.9	—	—	—	87.0	3.7 %
Thermal(1):											
High Vol A Bituminous	—	46.0	—	6.1	65.4	12.9	44.5	1,134.4	611.7	1,921.0	81.4 %
High Vol B Bituminous	—	—	—	—	101.1	—	—	139.3	—	240.4	10.3 %
High Vol C Bituminous	—	—	—	—	—	—	108.3	—	—	108.3	4.6 %
Low Vol Bituminous	—	—	—	—	—	—	—	—	4.5	4.5	0.2 %
Total Thermal	—	46.0	—	6.1	166.5	12.9	152.8	1,273.7	616.2	2,274.2	96.3 %
Total	—	51.1	16.0	6.1	166.5	78.8	152.8	1,273.7	616.2	2,361.2	100.0%
Percent of Total	— %	2.2 %	0.7 %	0.3%	7.1 %	3.2 %	6.5 %	53.9 %	26.1 %	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, 2016, 2015 and 2014.

Year	Total Royalty Tonnage (in thousands)	Total Coal Acreage Leased	Total Royalty Income (in thousands)
2016	3,530	213,371	$9,684
2015	7,459	235,066	$14,914
2014	10,230	281,894	$18,460

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, 2016, 100% of CONSOL Energy's production came from underground mines equipped with longwall mining systems. CONSOL Energy employs longwall mining systems in our underground mines where the geology is favorable and reserves are sufficient. Underground longwall systems are highly mechanized, capital intensive operations. Mines using longwall systems have a low variable cost structure compared with other types of mines and can achieve high productivity levels compared with those of other underground mining methods. Because CONSOL Energy has substantial reserves readily suitable to these operations, CONSOL Energy believes that these longwall mines can increase capacity at a low incremental cost.
The following table shows the production from continuing operations, in millions of tons, for CONSOL Energy's mines for the years ended December 31, 2016, 2015 and 2014, 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) 2016	2015	2014	Year Established or Acquired
PA Mining Operations								
Bailey	Enon, PA	U	LW/CM	R R/B	12.1	10.2	12.3	1984
Enlow Fork	Enon, PA	U	LW/CM	R R/B	9.6	9.0	10.6	1990
Harvey (3)	Enon, PA	U	LW/CM	R R/B	3.0	3.6	3.2	2014
Total					24.7	22.8	26.1	
CONSOL Energy Portion of Equity Affiliates								
Harrison Resources (1)(2)	Cadiz, OH	S	S/L	R T	—	—	0.3	2007
Western Allegheny (1)(2)	Young Township, PA	U	CM	R T	—	0.4	0.5	2010
Total CONSOL Energy Portion of Equity Affiliates					—	0.4	0.8	

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) — Harrison Resources,and Western Allegheny (includes facilities operated by independent contractors).
(2) — 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.
(3) — Completed development work and was placed in service in March 2014.

Coal Capital

In 2017, CONSOL Energy expects to invest $135 million in the PA Mining Operation division: $120 million allocated to production and $15 million allocated to other activities related to land, safety and water.

Coal Marketing and Sales

The following table sets forth the Company produced tons sold and average sales price for the period indicated:

	Years Ended December 31,		
	2016	2015	2014
Company Produced PA Mining Operations Tons Sold (in millions)	24.6	22.9	26.1
Average Sales Price Per Ton Sold– PA Mining Operations	$43.31	$56.36	$61.88

We sell coal produced by our mines 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.

Approximately 75% of our 2016 coal sales were made to U. S. electric generators, 22% of our 2016 coal sales were priced on export markets and 3% of our coal sales were made to other domestic customers. We had sales to over 35 customers from our 2016 coal operations. During 2016, two customers each comprised over 10% of our coal sales, and the top four coal customers accounted for over 40% of our coal sales.

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, 2016, over 65% of all the coal we produced was sold under contracts with terms of one year or more.

CONSOL Energy expects total consolidated PA Mining Operations annual sales to be approximately 26.0 million tons for both 2017 and 2018.

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;
- Base-price-plus-escalation methods which allow for periodic price adjustments based on inflation indices, or other negotiated indices; or
- Netback pricing.

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 operations to customers by railroad cars, trucks or a combination of these means of transportation. Most customers negotiate their own transportation rates and 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 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 2016, 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 63% of the tonnage shipped was produced by CONSOL Energy's PA Mining Operations. 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, 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, 2016, CONSOL Energy had 2,307 employees. There were no employees represented by the United Mine Workers of America (UMWA) at December 31, 2016.

Industry Segments

Financial information concerning industry segments, as defined by accounting principles generally accepted in the United States, for the years ended December 31, 2016, 2015 and 2014 is included in Note 23 - 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 natural gas and coal products.

Compliance with these laws has substantially increased the cost of natural gas production and mining of coal for all domestic natural 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 natural 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 natural 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 natural 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 $0.6 million, $18.4 million, and $19.0 million in the years ended December 31, 2016, 2015 and 2014, respectively. CONSOL Energy does not expect to have any capital expenditures in 2017 for environmental control facilities.

Environmental Laws

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

We are required to obtain pre-approval for construction or modification of certain facilities, to meet stringent air permit requirements, or to use specific equipment, technologies or best management practices to control emissions. On August 16, 2012, the U.S. Environmental Protection Agency (EPA) published final revisions to the New Source Performance Standards (NSPS) to regulate emissions of volatile organic compounds (VOCs) and sulfur dioxide (SO_2) from various oil and gas exploration, production, processing and transportation facilities. Additionally, revisions were made to the National Emission Standards for Hazardous Air Pollutants (NESHAPS) to further regulate emissions from the oil and natural gas production sector and the transmission and storage of natural gas. Section 111 of the CAA authorized the EPA to develop technology based standards which apply to specific categories of stationary sources.

On June 3, 2016, the EPA finalized updates to the final New Source Performance Standards (NSPS) that created new standards for the regulation of methane and VOC emission sources. The rule includes requirements for new fugitive emission and leak detection testing and reporting requirements. Also on June 3, 2016, the EPA published the final Source Determination Rule which clarified 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. On August 1, 2016 these updates to the NSPS were challenged in the D.C. Circuit Court of Appeals by industry and state associations and a request for administrative reconsideration was also filed. Additionally, 15 states filed suit and asked the Court of Appeals to review the need for the changes.

On November 30, 2016, the EPA finalized amendments to the Petroleum and Natural Gas Systems source category (Subpart W) of the Greenhouse Gas Reporting Program (GHGRP). This final rule adds new monitoring methods for detecting leaks from oil and gas equipment in the petroleum and natural gas systems source category consistent with the leak detection methods in the NSPS. The action also adds emission factors for leaking equipment to be used in conjunction with these monitoring methods to calculate and report greenhouse gas (GHG) emissions resulting from equipment leaks. The NSPS final rule would add reporting of GHG emissions from certain gathering and boosting systems, completions and workovers of oil wells using hydraulic fracturing, and blowdowns of natural gas transmission pipelines.

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 (CO_2), a regulated GHG, 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 New Source Performance Standards (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), SO_2 and nitrogen oxides (NO_X) 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.

The CAA requires the EPA to set National Ambient Air Quality Standards (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 Court of Appeals for the D.C. Circuit.

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 SO_2 and NO_X, as well as byproducts, fine particulate matter ($PM_{2.5}$) 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 vacated the rule. Following remand and briefing the D.C. Circuit Court of appeals, 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 September 7, 2016, the EPA finalized an update to the CSAPR for the 2008 ozone NAAQS by issuing the final CSAPR Update. Starting in May 2017, this rule will reduce summertime (May - September) NO_X emissions from power plants in 22 states in the eastern United States.

On March 27, 2012, the EPA published its proposed NSPS for CO_2 emissions from new coal-powered electric generating units. The proposed rule would have applied to new power plants and to existing plants that make major modifications. If the rule had been adopted as proposed, only new coal-fired power plants with CO_2 capture and storage (CCS) could have met the proposed emission limits. 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 CO_2 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 Clean Power Plan (CPP) proposal, the EPA would establish separate NSPS for CO_2 emissions for natural gas-fired turbines and coal-fired units. The proposed “Carbon Pollution Standard for New Power Plants” replaces the earlier proposal released by the EPA 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 would have become effective on October 23, 2015.

On June 2, 2014, the EPA proposed additional CPP legislation 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 GHG emissions from existing fossil fuel-fired electric generating units. Specifically, the EPA is proposing state-specific rate-based goals for CO_2 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 CPP Rule to cut carbon pollution from existing power plants, which would have become effective on December 22, 2015. Numerous petitions challenging the CPP Rule have been consolidated into one case, West Virginia v. EPA. While the litigation is still ongoing at the circuit court level, a mid-litigation application to the Supreme Court resulted in a stay of the Clean Power Plan Rule. On September 27, 2016, the en banc D.C. Circuit heard oral argument in the case and a decision is expected in early 2017.

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 draft report stated that hydraulic fracturing activities have not led to widespread, systemic impacts to drinking water resources. On December 13, 2016, the EPA released its final report on the impacts of hydraulic fracturing on drinking water. While the language was changed and included the possibility of impacts from hydraulic fracturing, it also included the guidance to industry and regulators on how the process can be done safely.

CONSOL Energy utilizes pipelines extensively for its natural gas, water and coal businesses. Mitigation permits from the Army Corps of Engineers (ACOE) are typically required for certain impacts these pipelines cause 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 of North Dakota blocked implementation of the rule in 13 states. On October 9, 2015, the Court of Appeals for the Sixth Circuit blocked implementation of the rule nationwide. The U.S. Supreme Court will now decide which court has jurisdiction - federal appeals court or district courts. A decision is expected sometime in mid 2017.

Safety of Gas Transmission and Gathering Pipelines. On April 8, 2016, The U.S. Department of Transportation (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) published in the Federal Register a Notice of Proposed Rule Making (NPRM) that would significantly modify existing regulations related to reporting, impact, design, construction, maintenance, operations and integrity management of gas transmission and gathering pipelines. The proposed rule addresses four congressional mandates and six recommendations by the National Transportation Safety Board. The proposed rule broadens the scope of safety coverage both by adding new assessment and repair criteria for gas transmission pipelines, and by expanding these protocols to include pipelines not formerly regulated by the federal standards. This means extending regulatory requirements to transmission and gathering pipelines of 8 inches and greater in rural class 1 areas, which could increase timeframes and cost to complete projects.

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 financial results, financial condition and cash flows. On December 28, 2016 the EPA entered into a consent order to resolve outstanding litigation brought by environmental and citizen groups regarding the applicability of RCRA to wastes from oil and gas development activities. The consent order requires the EPA to revise the applicability determination by March 15, 2019.

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.

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 Pennsylvania which has primary jurisdiction for enforcement of SMCRA through its approved state program. 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.

Federal and state laws require bonds to secure our obligations to reclaim lands used for mining and to satisfy other miscellaneous obligations. These bonds are typically renewable on a yearly basis. Surety bond costs have increased while the market terms of surety bonds have generally become less favorable. It is possible that surety-bond issuers may refuse to renew bonds or may demand additional collateral. Any failure to maintain, or inability to acquire, surety bonds that are required by state and federal laws would have a material adverse effect on our ability to produce coal, which could adversely affect our business, financial condition, results of operations, liquidity and cash flows.

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, the OSM published the proposed Stream Protection Rule (SPR). After much debate and thousands of comments, the final SPR was published by the OSM in the Federal Register on December 20, 2016. The final SPR requires the restoration of the physical form, hydrologic function, and ecological function of the segment of a perennial or intermittent stream that a permittee mines through. Additionally, it requires that the post-mining surface configuration of the reclaimed mine site include a drainage pattern, including ephemeral streams, similar to the pre-mining drainage pattern, with exceptions for stability, topographical changes, fish and wildlife habitat, etc. The rule also requires the establishment of a 100-foot-wide streamside vegetative corridor of native species (including riparian species, when appropriate) along each bank of any restored or permanently-diverted perennial, intermittent, or ephemeral stream. This rulemaking is highly anticipated to be subject to Legislative and Executive branch actions to overturn or significantly modify the rule.

Federal Regulation of the Sale and Transportation of Natural Gas

Regulations and orders set forth by the Federal Energy Regulatory Commission (FERC) impact our natural gas business to a certain degree. Although the FERC does not directly regulate our natural 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 natural 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 was implemented in three phases. The first phase began 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 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 ordered the necessary CPDM equipment required to meet compliance with the new rule at a cost of $2 million. We also hired Dust Coordinators and Dust Technicians to meet the staffing demand to manage compliance with the new rule. The final phase of the rule was effective on August 1, 2016. when the current respirable dust standard was 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 natural 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 oil and gas properties and coal properties prior to conducting operations on those properties. As is customary in the natural gas and coal industries, we have generally conducted only a summary review of the title to oil and gas rights 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, as part of an acquisition, 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, or negative credit market conditions may have a materially 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 2016 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;
- 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 natural 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 42% of the total company outside sales revenues from continuing operations in 2016, with natural gas and natural gas liquids representing 97% of the E&P division's outside sales revenues. Natural gas, natural gas liquids, oil and condensate 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 and the sale of our Buchanan Mine in 2016 increased our exposure to fluctuations in the price of natural gas, natural gas liquids, oil and condensate.

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 and 2016.

Our natural gas operations are geographically concentrated in the mid-Atlantic states. The success of the Marcellus Shale and Utica 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 and 2016, 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. The oversupply in the Appalachian Basin may persist if current pipeline projects to move gas out of the basin are delayed by permitting or environmental lawsuits.

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 capital expenditures and the drilling of new shale wells. In 2017, we expect our capital expenditures to increase to approximately $555 million from $227 million in 2016. 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 $829 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 have increased development activity in areas of shale formations which may also contain natural gas liquids, condensate and/or oil. The prices for natural gas liquids, condensate and oil are also volatile for reasons similar to those described above regarding natural gas. As a result of increasing supply, condensate and oil prices have exhibited great volatility. 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 60% since 2014 in the uplift we receive, on an Mcfe equivalent basis when excluding hedging impact, from natural gas liquids. Our results of operation may be adversely affected by a continued depressed level of or further downward fluctuations in natural gas liquids, condensate and oil prices.

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 of electricity and natural gas;
- weather conditions in our markets which affect the demand for natural gas and thermal coal (for example, the unusually warm 2015 - 2016 winter left utilities with large coal stockpiles and depressed the demand for thermal coal);
- 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; and
- 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.

The coal industry also faces concerns with respect to oversupply from time to time. For example, U.S. coal exports decreased by 32% during the first half of 2016 compared with the first half of 2015, as global supply exceeded demand for both thermal and metallurgical coal. Our average sales price per ton sold in 2016 declined 23% from 2015 due to imbalanced supply and demand, and a substantial or extended decline in the prices we receive for our coal could adversely affect our business, results of operations, financial condition, cash flows and liquidity.
Foreign currency fluctuations could adversely affect the competitiveness of our coal and natural gas liquids 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, 2016, approximately 65% 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 and electric power 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, 2016, we derived over 10% of our coal sales revenue from two coal customers individually and approximately 40% of our total sales revenue were derived from our four largest coal customers. At December 31, 2016, we had approximately nine coal supply agreements with these top two customers that expire at various times from 2017 to 2018. 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 have a materially adverse effect on our business, financial condition, results of operations and cash flows.

Our natural 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 natural 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.

Additionally, we have various firm transportation, natural gas processing, gathering and other agreements in place, many of which have minimum volume delivery commitments. Lower commodity prices may lead to reductions in our drilling program, which may result in insufficient production to utilize our full firm transportation and processing capacity. We are obligated to pay fees on minimum volumes to our service providers regardless of actual volume throughput. If we have insufficient production to meet the minimum volumes, our cash flow from operations will be reduced, which may require us to reduce or delay our planned investments and capital expenditures or seek alternative means of financing, all of which may have a material adverse effect 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 complex 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 most large coal companies have filed 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, which sales 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 it 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 the 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. Numerous petitions challenging the Clean Power Plan Rule have been consolidated into one case, West Virginia v. EPA. While the litigation is still ongoing at the circuit court level, a mid-litigation application to the Supreme Court resulted in a stay of the Clean Power Plan Rule. On September 27, 2016, an en banc panel of the U.S. Court of Appeals for the D.C. Circuit heard oral arguments in the case and a decision is expected in early 2017.

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. In addition, in November 2014, President Obama announced that the United States would seek to cut net greenhouse gas emissions 26-28 percent below 2005 levels by 2025 in return for China's commitment to seek to peak emissions around 2030, with concurrent increases in renewable energy. The United States participation in the Paris Agreement is unclear with the change in Administration in January 2017.

Additionally, coalbed methane must be expelled from our underground coal mines for mining safety reasons and is vented into the atmosphere when the coal is mined. Coalbed methane has a greater GHG effect than carbon dioxide. 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.

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 advisers, 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 endangered or 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. On January 14, 2016, the US Fish and Wildlife Service (USFWS) finalized a rule exempting certain types of “take” of northern long-eared bats from the requirement to obtain an incidental take permit, pursuant to Section 4(d) of the Endangered Species Act. This listing could lead to significant timing and critical path hurdles, ultimately limiting the ability to clear timber for construction activities in our operations area.

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 natural 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.

On December 19, 2016, the federal Office of Surface Mining released final regulations to the Stream Protection Rule, which is intended to prevent or minimize impacts to surface water and groundwater from coal mining. The rule will require companies to restore streams and return mined areas to the uses they were capable of supporting prior to mining activities, and replant these areas with native trees and vegetation, unless that would conflict with the implemented land use. The rule requires the testing and monitoring of the condition of streams that might be affected by mining - before, during and after their operations - to provide baseline data that ensures operators can detect and correct problems that could arise, and restore mined areas to their previous condition. The final SPR requires the restoration of the physical form, hydrologic function, and ecological function of the segment of a perennial or intermittent stream that a permittee mines through. Additionally, it requires that the post-mining surface configuration of the reclaimed mine site include a drainage pattern, including ephemeral streams, similar to the pre-mining drainage pattern, with exceptions for stability, topographical changes, fish and wildlife habitat, etc. The rule also requires the establishment of a 100-foot-wide streamside vegetative corridor of native species (including riparian species, when appropriate) along each bank of any restored or permanently-diverted perennial, intermittent, or ephemeral stream. This rulemaking is highly anticipated to be subject to Legislative and Executive branch actions to overturn or significantly modify the rule.

CONSOL Energy utilizes pipelines extensively for its natural gas, water and coal businesses. Mitigation permits from the Army Corps of Engineers (ACOE) are typically required for certain impacts these pipelines cause 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 of North Dakota blocked implementation of the rule in 13 states. On October 9, 2015, the Court of Appeals for the Sixth Circuit blocked implementation of the rule nationwide. The U.S. Supreme Court will now decide which court has jurisdiction - federal appeals court or district courts. A decision is expected sometime in mid 2017.

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.

State regulations for horizontal well drilling and well site construction have been proposed and finalized. In September, 2015, PA published a final rulemaking on the revisions to the Environmental Protection Performance Standards at Oil and Gas Well Sites (Chapters 78 and 78a). These rules are the subject of pending litigation. 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 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 2016 due to adverse geological conditions at Enlow Fork mine, primarily related to sandstone intrusions, which resulted in reduced coal production at that mine;

- 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 natural 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 2016 due to the oversupply of gas in our markets, we made payments under these contracts of approximately $33 million for field services that we did not use. 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 natural gas 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.

Additionally, we rely on a supply of drilling rigs, equipment, personnel and services in our naturual gas operations. The demand for this equipment and for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers, and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with natural gas and oil prices, causing periodic shortages. Historically, there have been shortages of drilling and workover rigs, pipe and other equipment as demand for rigs and equipment has increased along with the number of wells being drilled. We cannot predict whether these conditions will exist in the future and, if so, what their timing and duration will be. Such shortages could delay or cause us to incur significant expenditures that are not provided for in our capital budget, which 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 for on-going operations to continue mining continues to pose significant negative effects. Further, 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 costly stream mitigation and monitoring requirements and alterations to our longwall mining plans.

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 subsidiary Fola Coal Company, LLC, 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 natural gas operations.

Regulations applicable to the natural 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 the 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 commenced a study of the potential environmental impacts of hydraulic fracturing activities and the final report was issued in December 2016.

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.

On April 8, 2016, The U.S. Department of Transportation (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) published in the Federal Register a Notice of Proposed Rule Making (NPRM) that would significantly modify existing regulations related to reporting, impact, design, construction, maintenance, operations and integrity management of natural gas transmission and gathering pipelines. The proposed rule addresses four congressional mandates and six recommendations by the National Transportation Safety Board to broaden the scope of safety coverage by adding new assessment and repair criteria for gas transmission pipelines, and by expanding these protocols to include pipelines not formerly regulated by the federal standards. This includes extending regulatory requirements to transmission and gathering pipelines of 8 inches and greater in rural class 1 areas. Compliance with the rule, as proposed, may prove challenging and costly for operators of older pipelines due to the difficulty of locating historic records. Compliance could involve significant upfront costs and service disruptions. The relatively short 2-year timeframe for compliance for gathering pipelines could also be difficult to meet. Costs of compliance with the proposed rule could potentially affect shippers on pipelines as well as operators themselves, as the Federal Energy Regulatory Commission has allowed many interstate transmission pipelines to pass along costs attributable to safety measures directly to shippers. If implemented as proposed, CONSOL Energy (CONE & CNX Coal Resources) will be affected by this rulemaking. However, long-term costs for compliance will be dependent on the finalized version of the rule.

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 $474 million at December 31, 2016. 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. In an effort to settle a citizen suit filed in 2012 before the U.S. District Court in West Virginia related to the Special Reclamation Fund being underfunded the WV legislature authorized an increase in the per ton fee levied on coal production to make up the shortfall. The Special Reclamation Fund became fully funded in June of 2016. 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. Additionally, the sureties that post bonds on our behalf may require us to post security in order to secure the obligations underlying these bonds. Posting letters of credit in place of surety bonds or posting security to support these surety bonds would have an adverse effect on our liquidity.

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

Natural gas 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 reserves require subjective estimates of underground accumulations of natural gas assumptions concerning natural gas prices, production levels, reserve estimates and operating and development costs. As a result, estimated quantities of proved natural gas 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 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 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 properties also will be affected by factors such as:

- geological conditions;
- changes in governmental regulations and taxation;
- the amount and timing of actual production;
- assumptions governing future prices;

- future operating costs; and
- capital costs of drilling, completion and gathering assets.

The timing of both our production and our incurrence of expenses in connection with the development and production of natural gas properties will affect the timing of actual future net cash flows from proved reserves and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net cash flows may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas 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, 2016 would decrease from $1.6 billion to $1.4 billion.

We base our coal 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 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 natural gas reserves than a vertical well which could result in higher costs. In future years, the cost associated with purchasing 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 or undeveloped coal reserves where we have not done a thorough chain of title examination of our natural gas estate or undeveloped coal reserves. We may incur additional costs and delays to produce natural gas or mine coal because we have to acquire additional property rights to perfect our title to natural gas or coal rights. If we fail to acquire additional property rights to perfect our title to natural gas or coal 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.

Likewise, title to most of our owned or leased properties and mineral rights is not usually verified until we make a commitment to mine a property, which may not occur until after we have obtained necessary permits and completed exploration of the property. In some cases, we rely on title information or representations and warranties provided by our lessors or grantor's. Our right to mine certain of our reserves has in the past been, and may again in the future be, adversely affected if defects in title, boundaries or other rights necessary for mining exist or if a lease expires. Any challenge to our title or leasehold interests could delay the mining of the property and could ultimately result in the loss of some or all of our interest in the property. From time to time we also may be in default with respect to leases for properties on which we have mining operations. In such events, we may have to close down or significantly alter the sequence of such mining operations which may adversely affect our future coal production and future revenues. If we mine on property that we do not own or lease, we could incur liability for such mining and be subject to regulatory sanction and penalties.

In order to obtain, maintain or renew leases or mining contracts to conduct our mining operations on property where these defects exist, we may in the future have to incur unanticipated costs. In addition, we may not be able to successfully negotiate new leases or mining contracts for properties containing additional reserves, or maintain our leasehold interests in properties where we have not commenced mining operations during the term of the lease. As a result, our results of operations, business and financial condition may be materially adversely affected.

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’ alleged entitlements 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 22- 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, 2016, the current and non-current portions of these obligations included:

- postretirement medical and life insurance ($700 million);
- coal workers' black lung benefits ($119 million);
- salaried retirement benefits ($115 million); and
- workers' compensation ($80 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 and our collateral requirements. We post letters of credit and surety bonds as collateral for some of these liabilities that reduce our profitability and liquidity.

We do not control the timing of divestitures that we plan to engage in and they may not provide anticipated benefits. Additionally, we may be unable to acquire additional properties in the future and any acquired properties may not provide the anticipated benefits.

Our business and financing plans include divesting certain assets over time. However, we do not control the timing of divestitures and delays in entering into divestitures may reduce the benefits from them. Additionally, if assets are held jointly with another party, we may not be permitted to dispose of these assets without the consent of our joint venture partner. 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.

In the future we may make acquisitions of businesses that complement or expand our current business. No assurance can be given that we will be able to identify suitable acquisition opportunities, negotiate acceptable terms, obtain financing for acquisitions on acceptable terms or successfully acquire the identified targets. The success of any completed acquisition will depend on our ability to effectively integrate the acquired business into our existing operations. The process of integrating acquired businesses may involve unforeseen difficulties and may require a disproportionate amount of our managerial and financial resources. Our failure to make acquisitions in the future and successfully integrate the acquired businesses and assets into our existing operations could have a material adverse effect on our financial condition and results of operations

We may operate a material portion of our business with one or more joint venture partners. A joint venture may restrict our operational and corporate flexibility; actions taken by a joint venture partner may materially impact our financial position and results of operations; and we may not realize the benefits we expect to realize from a joint venture.

As is common in the industry we may operate one or more of our properties with a joint venture partner. These joint ventures could require us to share operational and other control with our joint venture partner, such that we may no longer have the flexibility to control completely the development of these properties. If we do not timely meet our financial commitments in a joint venture, our rights to participate in such joint venture will be adversely affected and the other party to the joint venture may have a right to acquire a share of our interest in such joint venture proportionate to, and in satisfaction of, our unmet financial obligations. If our joint venture partner is unable or fails to pay its portion of development costs, our costs of operations could be increased and it could result loss of rights to develop the properties held by that joint venture. We could also incur liability as a result of actions taken by our joint venture partner. Disputes between us and our joint venture partner 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.

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, 2016, our total long-term indebtedness was approximately \$2.80 billion of which approximately \$1.85 billion was under our 5.875% senior unsecured notes due 2022 plus \$5 million of unamortized bond premium, \$500 million was under our 8.000% senior unsecured notes due 2023 less \$6 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, \$49 million of capitalized leases due through 2021, \$5 million of miscellaneous debt and \$201 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 natural 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 reserves, our natural gas reserves and production will decline, which would adversely affect our business, financial condition, results of operations, liquidity and cash flows.

Producing natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Because total estimated proved reserves include our proved undeveloped reserves at December 31, 2016, production is expected to decline even if those proved undeveloped reserves are developed and the wells produce as expected. The rate of decline will change if production from our existing wells declines in a different manner than we have estimated and can change under other circumstances. Thus, our future natural gas reserves and production and, therefore, our cash flow and income are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire additional reserves to replace our current and future production at acceptable costs.

Our lenders use the loan value of our proved natural gas 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 prices, declines in natural gas 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 natural gas 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 2017. The various matters which we describe in other risk factors that can decrease our proved natural gas reserves including lower natural gas 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 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 reserves, our natural gas 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 17, 2017, we had hedges on approximately 311.3 Bcf of our 2017 natural gas production, 220.6 Bcf of our 2018 natural gas production, 161.7 Bcf of our 2019 natural gas production, 85.0 Bcf of our 2020 and natural gas production and 6.8 Bcf of our 2021 and natural gas production. To the extent that we engage in hedging activities, we may be prevented from realizing the near-term 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;
- the creditworthiness of our counterparties or their guarantors is substantially impaired;
- counterparties have credit limits that may constrain our ability to hedge additional volumes.

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%.We believe our maximum estimated exposure under our Murray Energy guarantees as of December 31, 2016 was approximately $74 million. The leases and subleases we entered into with Murray Energy relate to approximately $106 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 estimated that the servicing cost for these liabilities would be approximately $26 million for 2017 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). Since the transaction, Murray Energy's credit ratings have been downgraded by Moody's. In November, 2016, Moody's upgraded Murray Energy to a family credit rating of Caa2 and the rating on its secured second lien notes to Caa3 with a stable 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 natural 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 are from three mines at one location in Pennsylvania, making us vulnerable to risks associated with operating in a single geographic area.

The substantial majority of our sales of thermal coal, as well as our thermal coal reserves, are from our Bailey Mine, Enlow Fork Mine and HarveyMine 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 coal and adversely affect our results of operation and financial condition.

Certain provisions in our multi-year coal 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 coal 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 coal 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 coal sales agreements contain provisions requiring us to deliver coal within certain ranges for specific coal quality characteristics such as heat content, sulfur, ash, moisture, volatile matter, grindability, ash fusion temperature and size consist. Failure to meet these conditions could result in penalties or rejection of the coal at the election of the customer. Our coal 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.

The majority 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.

As of December 31, 2016, we hold 11.6 million subordinated units (representing a 42.7 percent limited partnership interest) in CNX Coal Resources LP, which we call CNXC. The balance of our CNXC limited partnership interests are held in the form of preferred and common units. Subordinated units are not entitled to any distribution from CNXC unless CNXC makes a minimum quarterly distribution of $0.4678 per Class A Preferred Unit and $0.5125 per common unit. CNXC made minimum distributions per subordinated unit equal to the distribution per common unit for five of the six quarters since CNXC’s IPO. CNXC did not met the requirement for a subordinated unit distribution with respect to fiscal quarter ended June 30, 2016 and we did not receive a distribution per subordinated unit, however, CNXC was able to make minimum distributions per subordinated unit equal to the distribution per common unit with respect to the fiscal quarter ended September 30, 2016 and declared minimum distributions per subordinated unit equal to the distribution per common unit with respect to the fiscal quarter ended December 31, 2016. We cannot assure you that CNXC will continue to be able to make or will make the required minimum quarterly distribution on its preferred and 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 23.0 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 “E&P 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 seventh paragraphs of Note 22–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, 2016			
Quarter Ended March 31, 2016	$12.42	$4.54	$ 0.0100
Quarter Ended June 30, 2016	$16.40	$10.53	$ —
Quarter Ended September 30, 2016	$19.76	$15.03	$ —
Quarter Ended December 31, 2016	$22.34	$16.14	$ —
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

As of December 31, 2016, there were 127 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, Arch Coal Inc., Chesapeake Energy Corp., Devon Energy Corp., EOG Resources Inc., Noble Energy Inc., Peabody Energy Corp., Southwestern Energy Co., QEP Resources Inc., 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, 2011. The graph also assumes that all dividends were reinvested and that the investments were held through December 31, 2016.

	2011	2012	2013	2014	2015	2016
CONSOL Energy Inc.	100.0	88.1	103.4	91.7	21.7	49.1
Peer Group	100.0	96.8	111.0	76.5	35.0	87.3
S&P 500 Stock Index	100.0	111.4	144.4	160.8	159.7	174.9

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 suspended its quarterly dividend following the sale of the Buchanan Mine on March 31, 2016 to further reflect the Company's increased emphasis on growth. 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 4.53 to 1.00 and the cumulative credit was approximately $781 million at December 31, 2016. 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, 2016.
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, 2016, 2015, 2014, 2013 and 2012 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, 2016 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.

(Dollars in thousands, except per share data)	For the Years Ended December 31,				
	2016	2015	2014	2013	2012
Operating revenues from Continuing Operations	$1,839,571	$2,474,815	$2,953,365	$2,400,187	$2,387,093
(Loss) Income from Continuing Operations	$(535,965)	$(350,266)	$164,947	$(16,393)	$245,663
Net (Loss) Income Attributable to CONSOL Energy Inc. Shareholders	$(848,102)	$(374,885)	$163,090	$660,442	$388,470
Earnings (Loss) per share:					
Basic:					
(Loss) Income from Continuing Operations	$(2.38)	$(1.57)	$0.72	$(0.07)	$1.08
(Loss) Income from Discontinued Operations	(1.32)	(0.07)	(0.01)	2.96	0.63
Net (Loss) Income	$(3.70)	$(1.64)	$0.71	$2.89	$1.71
Dilutive:					
(Loss) Income from Continuing Operations	$(2.38)	$(1.57)	$0.71	$(.07)	$1.07
(Loss) Income from Discontinued Operations	(1.32)	(0.07)	(0.01)	2.94	0.63
Net (Loss) Income	$(3.70)	$(1.64)	$0.70	$2.87	$1.70
Assets from Continuing Operations	$9,183,898	$9,908,082	$10,645,099	$10,105,731	$8,593,069
Assets from Discontinued Operations	83	1,021,820	1,009,546	1,042,204	3,770,061
Total Assets	$9,183,981	$10,929,902	$11,654,645	$11,147,935	$12,363,130
Long-Term Debt from Continuing Operations (including current portion)	$2,774,069	$3,700,192	$3,247,407	$3,137,522	$3,140,656
Long-Term Debt from Discontinued Operations (including current portion)	—	6,665	3,171	3,063	5,640
Total Long-Term Debt (including current portion)	$2,774,069	$3,706,857	$3,250,578	$3,140,585	$3,146,296
Cash Dividends Declared Per Share of Common Stock	$0.010	$0.145	$0.250	$0.375	$0.625

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.

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OTHER OPERATING DATA
(unaudited)

	Years Ended December 31,				
	2016	2015	2014	2013	2012
Gas:					
Net sales volumes produced (in Bcfe)	394.4	328.7	235.7	172.4	156.3
Average sales price ($ per Mcfe) (A)	$2.63	$2.81	$4.37	$4.30	$4.22
Average cost ($ per Mcfe)	$2.32	$2.62	$3.13	$3.42	$3.28
Proved reserves (in Bcfe) (B)	6,252	5,643	6,828	5,731	3,993
Coal:					
Tons sold from continuing operations (in thousands)	24,604	22,873	26,133	21,230	19,570
Tons produced from continuing operations (in thousands)	24,666	22,790	26,066	21,433	19,582
Average sales price of tons produced ($ per ton produced)	$43.31	$56.36	$61.88	$63.93	$67.67
Average Cost of Goods Sold ($ per ton produced)	$34.35	$41.78	$43.63	$44.53	$44.62
Recoverable coal reserves (tons in millions) (C)	2,361	3,047	3,238	3,032	4,229
Number of active mining complexes (at end of period)	1	1	1	1	1

(A) Represents average net sales price including the effect of derivative transactions.
(B) Represents proved developed and undeveloped gas reserves at period end.
(C) Represents proven and probable coal reserves at period end, including discontinued operations and excluding equity affiliates.

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

General

2016 Highlights

- Record total gas production of 394.4 Bcfe in 2016, 20.0% higher than 2015.
- Record Marcellus Shale production of 212.5 Bcfe in 2016, 23.3% higher than 2015.
- Record Utica Shale production of 90.8 Bcfe in 2016, 61.6% higher than 2015.
- In March 2016, CONSOL Energy completed the sale of its membership interests in CONSOL Buchanan Mining Company, LLC (BMC), which owned and operated the Buchanan Mine located in Mavisdale, Virginia, various assets relating to the Amonate Mining Complex located in Amonate, Virginia; and various coal reserves. Cash proceeds of $402,799 were received at closing.
- In August 2016, CONSOL Energy completed the sale of its Miller Creek Mining Complex and Fola Mining Complex subsidiaries. CONSOL Energy paid $28,271 of cash at closing. In addition, CONSOL Energy will pay a total of $17,200 in installments over the next four years.
- In November 2016, cash proceeds of $70,000 were received in connection with our equity affiliate CONE Midstream Partners LP acquiring an additional 25% interest in CONE Midstream DevCo I LP, commonly referred to as the "Anchor Systems."
- In December 2016, with an effective date of October 1, 2016, CONSOL Energy terminated the 50-50 Joint Venture that was formed in 2011, with Noble Energy, Inc., for the exploration, development, and operation of primarily Marcellus Shale properties in Pennsylvania and West Virginia. Highlights include: each party will own and operate a 100% interest in its properties and wells in two separate operating areas; each party will have independent control and flexibility with respect to the scope and timing of future development over its operating area; and all acreage operated by CONSOL Energy and Noble Energy, Inc. in their respective operating areas will remain fully dedicated to CONE Midstream Partners LP. Cash proceeds of $213,295 were received at closing.
- Gas production costs continue to decline - for the year ended December 31, 2016, total gas production costs were $2.32 per Mcfe, an 11.5% decline from the prior year.
- Made payments on the senior secured credit facility of $952,000, resulting in zero drawings at the end of 2016, increasing liquidity.

2017 Outlook:

- Our 2017 annual gas production is expected to increase to approximately 415 Bcfe.
- Our 2017 E&P capital investment is expected to be approximately $555 million.
- Our 2017 coal production is expected to be approximately 26.0 million tons.
- Our 2017 coal capital investment is expected to be approximately $135 million.

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Results of Operations: Year Ended December 31, 2016 Compared with the Year Ended December 31, 2015
Net Loss Attributable to CONSOL Energy Shareholders
CONSOL Energy reported a net loss attributable to CONSOL Energy shareholders of $848 million, or a loss per diluted share of $3.70, for the year ended December 31, 2016, compared to a net loss attributable to CONSOL Energy shareholders of $375 million, or a loss per diluted shared of $1.64, for the year ended December 31, 2015.

	For the Years Ended December 31,		
(Dollars in thousands)	2016	2015	Variance
Loss from Continuing Operations	$(535,965)	$(350,266)	$(185,699)
Loss from Discontinued Operations	(303,183)	(14,209)	(288,974)
Net Loss	$(839,148)	$(364,475)	$(474,673)
Less: Net Income Attributable to Noncontrolling Interests	8,954	10,410	(1,456)
Net Loss Attributable to CONSOL Energy Shareholders	$(848,102)	$(374,885)	$(473,217)

CONSOL Energy consists of two principal business divisions: Exploration and Production (E&P) and Pennsylvania (PA) Mining Operations. The E&P division includes four reportable segments: Marcellus, Utica, Coalbed Methane (CBM) and Other Gas.

The E&P division had a loss before income tax of $379 million for the year ended December 31, 2016, compared to a loss before income tax of $679 million for the year ended December 31, 2015. Included in the 2016 net loss before income tax was an unrealized loss on commodity derivative instruments of $386 million. Included in the 2015 net loss before income tax was a 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 depressed NYMEX forward strip prices (see Note 9 - Property, Plant and Equipment of the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information). The impairment loss was partially off-set by an unrealized gain on commodity derivative instruments of $197 million.

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

	For the Years Ended December 31,			
in thousands (unless noted)	2016	2015	Variance	Percent Change
LIQUIDS				
NGLs:				
Sales Volume (MMcfe)	40,260	33,180	7,080	21.3 %
Sales Volume (Mbbls)	6,710	5,530	1,180	21.3 %
Gross Price ($/Bbl)	$14.52	$12.30	$2.22	18.0 %
Gross Revenue	$97,580	$68,057	$29,523	43.4 %
Oil:				
Sales Volume (MMcfe)	410	592	(182)	(30.7)%
Sales Volume (Mbbls)	68	99	(31)	(31.3)%
Gross Price ($/Bbl)	$36.90	$47.94	$(11.04)	(23.0)%
Gross Revenue	$2,521	$4,736	$(2,215)	(46.8)%
Condensate:				
Sales Volume (MMcfe)	4,964	7,598	(2,634)	(34.7)%
Sales Volume (Mbbls)	827	1,266	(439)	(34.7)%
Gross Price ($/Bbl)	$27.48	$26.52	$0.96	3.6 %
Gross Revenue	$22,748	$33,586	$(10,838)	(32.3)%

GAS				
Sales Volume (MMcf)	348,753	287,287	61,466	21.4 %
Sales Price ($/Mcf)	$1.92	$2.17	$(0.25)	(11.5)%
Gross Revenue	$670,823	$622,080	$48,743	7.8 %
Hedging Impact ($/Mcf)	$0.70	$0.68	$0.02	2.9 %
Gain on Commodity Derivative Instruments - Cash Settlement	$245,212	$196,348	$48,864	24.9 %

The E&P division natural gas, NGLs, and oil sales were $794 million for the year ended December 31, 2016, compared to $729 million for the year ended December 31, 2015. The increase was primarily due to the 20.0% increase in total E&P sales volumes, offset in part by the 11.5% decrease in the average gas sales price per Mcf without the impact of derivative instruments from the table above. The decrease in average sales price was the result of the overall decrease in general market prices.

The E&P division sales volumes, average sales price (including the effects of derivatives instruments), and average costs for all active E&P operations were as follows:

	For the Years Ended December 31,			
	2016	2015	Variance	Percent Change
E&P Sales Volumes (Bcfe)	394.4	328.7	65.7	20.0 %
Average Sales Price (per Mcfe)	$2.63	$2.81	$(0.18)	(6.4)%
Average Costs (per Mcfe)	2.32	2.62	(0.30)	(11.5)%
Average Margin	$0.31	$0.19	$0.12	63.2 %

Changes in the average costs per Mcfe were primarily related to the following items:

- The improvement in unit costs is primarily due to the continuing shift towards lower cost Marcellus and dry Utica Shale production, ongoing cost reduction efforts and the 20.0% increase in total volumes sold in the period-to-period comparison. Marcellus production made up 53.9% of E&P sales volumes in the year ended December 31, 2016, compared to 52.4% in the year ended December 31, 2015. Utica production made up 23.0% of E&P sales volumes in the year ended December 31, 2016, compared to 17.1% in the year ended December 31, 2015.
- Lifting costs per unit decreased in the period-to-period comparison primarily due to the increase in overall sales volumes, as well as a decrease in well site maintenance costs, employee related costs and costs related to wells operated by the Company's joint venture partners. The decrease was offset, in part, by an increase in total dollars relating to higher salt water disposal costs.
- Transportation, gathering and compression expense decreased on a per unit basis in the period-to-period comparison due to the overall increase in E&P sales volumes, the shift towards dry Utica Shale production which has lower gathering costs since there are no associated processing fees and a decrease in pipeline and facility maintenance expense. The decrease in unit costs was partially offset by an increase in total dollars related to an increase in utilized firm transportation costs, increased processing fees associated with NGLs, and an increase in CONE gathering expense directly related to the increase in Marcellus production. See Note 25 - Related Party Transactions of the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.

The PA Mining Operations division had earnings before income tax of $131 million for the year ended December 31, 2016, compared to earnings before income tax of $405 million for the year ended December 31, 2015.

Sales tons, average sales price and average cost of goods sold per ton for the PA Mining Operations division were as follows:

	For the Years Ended December 31,			
	2016	2015	Variance	Percent Change
Company Produced PA Mining Operations Tons sold (in millions)	24.6	22.9	1.7	7.4 %
Average Sales Price per ton sold	$43.31	$56.36	$(13.05)	(23.2)%
Average Costs of Goods Sold per ton sold	34.35	41.78	(7.43)	(17.8)%
Average Margin	$8.96	$14.58	$(5.62)	(38.5)%

The lower average sales price per ton sold in the 2016 period was primarily the result of the overall decline in the domestic and global thermal coal markets, particularly in the first half of 2016. This decline was primarily related to higher customer inventories and lower gas prices after persistently mild 2015 weather. This was off-set by an increase in overall tons sold reflecting the improvement in both domestic and international coal demand throughout the second half of 2016.

The PA Mining Operations division priced 5.4 million tons on the export market for the year ended December 31, 2016, compared to 5.5 million tons for the year ended December 31, 2015. All other tons were sold on the domestic market.

Changes in the average cost of goods sold per ton were primarily driven by the idling of one longwall at the PA Mining Operations complex for approximately 90 days, a reduction of staffing levels and a realignment of employee benefits in the current year. All of the above steps resulted in more consistent operating schedules, reduced labor costs, and improved productivity.

The Other division includes other business activities not assigned to the E&P or PA Mining Operations division and income taxes. The Other division had a net loss of $287 million for the year ended December 31, 2016, compared to a net loss of $77 million for the year ended December 31, 2015.

Selling, general and administrative (SG&A) costs are allocated to the PA Mining Operations division based upon a shared service agreement that CONSOL Energy entered into with CNX Coal Resources LP (CNXC) upon execution of the CNXC initial public offering (IPO). The shared service agreement calls for CONSOL Energy to provide certain selling, general and administrative services that are paid for monthly, based on an agreed upon fixed fee that is reset at least annually. See Note 25 - Related Party Transactions of the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information. The remaining SG&A costs are allocated between the E&P and Other divisions based primarily on a percentage of total revenue and a percentage of total projected capital expenditures.

SG&A costs are excluded from the E&P and PA Mining Operations unit costs above. SG&A costs were $153 million for the year ended December 31, 2016, compared to $158 million for the year ended December 31, 2015. SG&A costs decreased due to the following items:

	For the Years Ended December 31,			
(in millions)	2016	2015	Variance	Percent Change
Short-Term Incentive Compensation	$29	$40	$ (11)	(27.5)%
Employee Wages and Related Expenses	54	62	(8)	(12.9)%
Advertising and Promotion	5	7	(2)	(28.6)%
Rent	8	8	—	— %
Consulting and Professional Services	15	15	—	— %
Contributions	1	1	—	— %
Stock-Based Compensation	31	25	6	24.0 %
Other	10	—	10	100.0 %
Total Company Selling, General and Administrative Expense	$153	$158	$ (5)	(3.2)%

- The decrease in Short-Term Incentive Compensation was a result of lower payouts in the current year.
- Employee Wages and Related Expenses decreased $8 million primarily due to the Company reorganization that occurred in the second half of 2015 and the first quarter of 2016, which resulted in an overall decrease in employees.
- Stock-Based Compensation increased $6 million in the period-to-period comparison primarily due to additional non-cash amortization expense recorded in the current period for the Performance Share Unit (PSU) program.
- Other increased $10 million in the period-to-period comparison primarily due to a 401(k) discretionary contribution in the current period.

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 the segments based upon criteria specific to each liability. Total CONSOL Energy continuing operations expense related to actuarial liabilities was $74 million for the year ended December 31, 2016, compared to income of $162 million for the year ended December 31, 2015. The increase of $236 million is primarily due to modifications made to the OPEB and Pension plans in May 2015. See Note 14—Pension and Other Postretirement Benefit Plans and Note 15—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.

TOTAL E&P DIVISION ANALYSIS for the year ended December 31, 2016 compared to the year ended December 31, 2015:

The E&P division had a loss before income tax of $379 million for the year ended December 31, 2016 compared to a loss before income tax of $679 million for the year ended December 31, 2015. Variances by individual E&P segment are discussed below.

	For the Year Ended December 31, 2016					Difference to Year Ended December 31, 2015				
(in millions)	Marcellus	Utica	CBM	Other Gas	Total E&P	Marcellus	Utica	CBM	Other Gas	Total E&P
Natural Gas, NGLs and Oil Sales	$415	$163	$175	$41	$794	$36	$70	$(27)	$(14)	$65
Gain (Loss) on Commodity Derivative Instruments	147	29	52	(369)	(141)	46	23	(15)	(588)	(534)
Purchased Gas Sales	—	—	—	43	43	—	—	—	29	29
Miscellaneous Other Income	—	—	—	81	81	—	—	—	19	19
Gain on Sale of Assets	—	—	—	14	14	—	—	—	1	1
Total Revenue and Other Income	562	192	227	(190)	791	82	93	(42)	(553)	(420)
Lease Operating Expense	34	22	25	15	96	(10)	—	(8)	(8)	(26)
Production, Ad Valorem, and Other Fees	17	5	6	3	31	(1)	3	(1)	—	1
Transportation, Gathering and Compression	228	51	72	23	374	28	16	(13)	—	31
Depreciation, Depletion and Amortization	211	86	86	35	418	49	27	2	(31)	47
Exploration and Production Related Other Costs	—	—	—	15	15	—	—	—	5	5
Purchased Gas Costs	—	—	—	43	43	—	—	—	32	32
Other Corporate Expenses	—	—	—	88	88	—	—	—	22	22
Impairment of Exploration and Production Properties	—	—	—	—	—	—	—	—	(829)	(829)
Selling, General and Administrative Costs	—	—	—	102	102	—	—	—	—	—
Total Exploration and Production Costs	490	164	189	324	1,167	66	46	(20)	(809)	(717)
Interest Expense	—	—	—	3	3	—	—	—	(3)	(3)
Total E&P Division Costs	490	164	189	327	1,170	66	46	(20)	(812)	(720)
Earnings (Loss) Before Income Tax	$72	$28	$38	$(517)	$(379)	$16	$47	$(22)	$259	$300

MARCELLUS SEGMENT

The Marcellus segment had earnings before income tax of $72 million for the year ended December 31, 2016 compared to earnings before income tax of $56 million for the year ended December 31, 2015.

	For the Years Ended December 31,			
	2016	2015	Variance	Percent Change
Marcellus Gas Sales Volumes (Bcf)	186.8	149.4	37.4	25.0 %
NGLs Sales Volumes (Bcfe)*	23.5	19.0	4.5	23.7 %
Condensate Sales Volumes (Bcfe)*	2.2	3.9	(1.7)	(43.6)%
Total Marcellus Sales Volumes (Bcfe)*	212.5	172.3	40.2	23.3 %
Average Sales Price - Gas (Mcf)	$ 1.87	$ 2.09	$ (0.22)	(10.5)%
Gain on Commodity Derivative Instruments - Cash Settlement- Gas (Mcf)	$ 0.79	$ 0.67	$ 0.12	17.9 %
Average Sales Price - NGLs (Mcfe)*	$ 2.38	$ 2.54	$ (0.16)	(6.3)%
Average Sales Price - Condensate (Mcfe)*	$ 4.32	$ 5.02	$ (0.70)	(13.9)%
Total Average Marcellus Sales Price (per Mcfe)	$ 2.64	$ 2.79	$ (0.15)	(5.4)%
Average Marcellus Lease Operating Expenses (per Mcfe)	0.16	0.26	(0.10)	(38.5)%
Average Marcellus Production, Ad Valorem, and Other Fees (per Mcfe)	0.08	0.10	(0.02)	(20.0)%
Average Marcellus Transportation, Gathering and Compression Costs (per Mcfe)	1.07	1.16	(0.09)	(7.8)%
Average Marcellus Depreciation, Depletion and Amortization Costs	0.99	0.94	0.05	5.3 %

(per Mcfe)										
Total Average Marcellus Costs (per Mcfe)	$	2.30	$	2.46	$	(0.16	)	(6.5	)%
Average Margin for Marcellus (per Mcfe)	$	0.34	$	0.33	$	0.01		3.0	%

* 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 had natural gas, NGLs and oil sales of $415 million for the year ended December 31, 2016 compared to $379 million for the year ended December 31, 2015. The $36 million increase is primarily due to a 23.3% increase in total Marcellus sales volumes, partially offset by a 10.5% decrease in the average gas sales price in the period-to-period comparison. The increase in total sales volumes is primarily due to additional wells coming on-line in the current year, as well as the termination of the Marcellus Joint Venture that CONSOL Energy had with Noble Energy (See Note 9 - Property, Plant and Equipment in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional details). The joint venture termination was effective October 1st, 2016 and resulted in additional production for the fourth quarter of 2016, as well as the applicable sales and production costs.

The decrease in the total average Marcellus sales price was primarily the result of the $0.22 per Mcf decrease in gas market prices, along with a $0.03 per Mcf decrease in the uplift from NGLs and condensate sales volumes, when excluding the impact of hedging. These decreases were offset, in part, by a $0.12 per Mcf increase in the gain on commodity derivative instruments resulting from the Company's hedging program. The increase in the gain was due to an increase in volumes hedged and lower market prices. The notional amounts associated with these financial hedges represented approximately 160.8 Bcf of the Company's produced Marcellus gas sales volumes for the year ended December 31, 2016 at an average gain of $0.92 per Mcf. For the year ended December 31, 2015, these financial hedges represented approximately 90.3 Bcf at an average gain of $1.09 per Mcf.

Total exploration and production costs for the Marcellus segment were $490 million for the year ended December 31, 2016 compared to $424 million for the year ended December 31, 2015. The increase in total dollars and decrease in unit costs for the Marcellus segment were due to the following items:

•Marcellus lease operating expense was $34 million for the year ended December 31, 2016 compared to $44 million for the year ended December 31, 2015. The decrease in total dollars was primarily due to a reduction in employee related costs, well tending costs and repairs and maintenance expense in the current period. The reduction in employee related costs was primarily due to the company reorganization that occurred in the second half of 2015 and the first quarter of 2016. The decrease in unit costs was primarily due to the 23.3% increase in total Marcellus sales volumes, along with the decreased total dollars described above. The decreases were offset, in part, by an increase in salt water disposal costs in the period-to-period comparison.

•Marcellus production, ad valorem, and other fees were $17 million for the year ended December 31, 2016 compared to $18 million for the year ended December 31, 2015. The decrease in total dollars was primarily due to the decrease in total average Marcellus sales price, offset, in part, by the increase in total Marcellus sales volumes.

•Marcellus transportation, gathering and compression costs were $228 million for the year ended December 31, 2016 compared to $200 million for the year ended December 31, 2015. The $28 million increase in total dollars was primarily related to an increase in the CONE gathering fee due to the increase in total Marcellus sales volumes (See Note 25 - 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 23.7% increase in NGLs sales volumes, and an increase in utilized firm transportation expense. The decrease in unit costs was due to the increase in total Marcellus sales volumes, offset, in part, by the increase in total dollars.

•Depreciation, depletion and amortization costs attributable to the Marcellus segment were $211 million for the year ended December 31, 2016 compared to $162 million for the year ended December 31, 2015 driven primarily by the overall increase in production. These amounts included depletion on a unit of production basis of $0.98 per Mcf and $0.92 per Mcf, respectively. The remaining depreciation, depletion and amortization costs were either recorded on a straight-line basis or related to gas well closing.

UTICA SEGMENT

The Utica segment had earnings before income tax of $28 million for the year ended December 31, 2016 compared to a loss before income tax of $19 million for the year ended December 31, 2015.

	For the Years Ended December 31,								
	2016		2015		Variance			Percent Change	
Utica Gas Sales Volumes (Bcf)	71.3		38.3		33.0			86.2	%
NGLs Sales Volumes (Bcfe)*	16.7		14.1		2.6			18.4	%
Oil Sales Volumes (Bcfe)*	—		0.1		(0.1		)	(100.0	)%
Condensate Sales Volumes (Bcfe)*	2.8		3.7		(0.9		)	(24.3	)%
Total Utica Sales Volumes (Bcfe)*	90.8		56.2		34.6			61.6	%
Average Sales Price - Gas (Mcf)	$	1.52	$	1.52	$	—		—	%
Gain on Commodity Derivative Instruments - Cash Settlement- Gas (Mcf)	$	0.41	$	0.17	$	0.24		141.2	%
	$	2.49	$	1.39	$	1.10		79.1	%

Average Sales Price - NGLs (Mcfe)*											
Average Sales Price - Oil (Mcfe)*	$	—		$	6.58		$	(6.58	)	(100.0	)%
Average Sales Price - Condensate (Mcfe)*	$	4.78		$	3.79		$	0.99		26.1	%
Total Average Utica Sales Price (per Mcfe)	$	2.12		$	1.75		$	0.37		21.1	%
Average Utica Lease Operating Expenses (per Mcfe)	0.25			0.39			(0.14		)	(35.9	)%
Average Utica Production, Ad Valorem, and Other Fees (per Mcfe)	0.05			0.04			0.01			25.0	%
Average Utica Transportation, Gathering and Compression Costs (per Mcfe)	0.57			0.61			(0.04		)	(6.6	)%
Average Utica Depreciation, Depletion and Amortization Costs (per Mcfe)	0.94			1.06			(0.12		)	(11.3	)%
Total Average Utica Costs (per Mcfe)	$	1.81		$	2.10		$	(0.29	)	(13.8	)%
Average Margin for Utica (per Mcfe)	$	0.31		$	(0.35	)	$	0.66		188.6	%

*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 had natural gas, NGLs and oil sales of $163 million for the year ended December 31, 2016 compared to $93 million for the year ended December 31, 2015. The $70 million increase was primarily due to the 61.6% increase in total

Utica sales volumes. The 34.6 Bcfe increase in total Utica sales volumes was due to additional wells coming on-line, primarily in dry Utica areas, in the current period.

The increase in the total average Utica sales price was primarily due to a $0.24 per Mcf increase in the gain on commodity derivative instruments in the current period, as well as a $0.16 per Mcf increase in the uplift from NGLs and condensate sales volumes. The increase in the hedging gain was due to an increase in the volumes hedged that were designated as Utica volumes. Financial hedges represented approximately 31.6 Bcf of the Company's produced Utica gas sales volumes for the year ended December 31, 2016 at an average gain of $0.93 per Mcf. For the year ended December 31, 2015, these financial hedges represented approximately 5.9 Bcf at an average gain of $1.08 per Mcf.

Total exploration and production costs for the Utica segment were $164 million for the year ended December 31, 2016 compared to $118 million for the year ended December 31, 2015. The increase in total dollars and decrease in unit costs for the Utica segment are due to the following items:

•Utica lease operating expense remained flat at $22 million for each of the years ended December 31, 2016 and December 31, 2015. The decrease in unit costs was primarily due to the 61.6% increase in total Utica sales volumes.

•Utica production, ad valorem, and other fees were $5 million for the year ended December 31, 2016 compared to $2 million for the year ended December 31, 2015. The increase in total dollars was primarily due to the 61.6% increase in total Utica sales volumes. The increase in unit costs was also due to a credit received from a joint venture partner in the 2015 period, related to an over-billing of ad valorem taxes.

•Utica transportation, gathering and compression costs were $51 million for the year ended December 31, 2016 compared to $35 million for the year ended December 31, 2015. The $16 million increase in total dollars was primarily related to increased gathering and processing fees associated with the increased Utica NGLs and gas sales volumes. The decrease in unit costs was due to the increase in total Utica sales volumes, predominantly dry Utica, which was offset, in part, by the increase in total dollars.

•Depreciation, depletion and amortization costs attributable to the Utica segment were $86 million for the year ended December 31, 2016 compared to $59 million for the year ended December 31, 2015 driven primarily by the overall increase in production. These amounts included depletion on a unit of production basis of $0.93 per Mcf and $1.05 per Mcf, respectively. The remaining depreciation, depletion and amortization costs were either recorded on a straight-line basis or related to gas well closing.

COALBED METHANE (CBM) SEGMENT

The CBM segment had earnings before income tax of $38 million for the year ended December 31, 2016 compared to earnings before income tax of $60 million for the year ended December 31, 2015.

	For the Years Ended December 31,			
	2016	2015	Variance	Percent Change
CBM Gas Sales Volumes (Bcf)	69.0	74.9	(5.9)	(7.9)%
Average Sales Price - Gas (Mcf)	$2.53	$2.70	$ (0.17)	(6.3)%
Gain on Commodity Derivative Instruments - Cash Settlement- Gas (Mcf)	$0.76	$0.90	$ (0.14)	(15.6)%
Total Average CBM Sales Price (per Mcf)	$3.29	$3.60	$ (0.31)	(8.6)%

Average CBM Lease Operating Expenses (per Mcf)	0.36	0.44	(0.08)	(18.2)%
Average CBM Production, Ad Valorem, and Other Fees (per Mcf)	0.09	0.10	(0.01)	(10.0)%
Average CBM Transportation, Gathering and Compression Costs (per Mcf)	1.04	1.13	(0.09)	(8.0)%
Average CBM Depreciation, Depletion and Amortization Costs (per Mcf)	1.25	1.13	0.12	10.6 %
Total Average CBM Costs (per Mcf)	$2.74	$2.80	$ (0.06)	(2.1)%
Average Margin for CBM (per Mcf)	$0.55	$0.80	$ (0.25)	(31.3)%

The CBM segment had natural gas sales of $175 million for the year ended December 31, 2016 compared to $202 million for the year ended December 31, 2015. The $27 million decrease was primarily due to a 6.3% decrease in the average gas sales price, as well as a 7.9% decrease in CBM gas sales volumes. The decrease in CBM sales volumes was primarily due to normal well declines and less drilling activity.

The total average CBM sales price decreased $0.31 per Mcf due primarily to a $0.17 per Mcf decrease in gas market prices, as well as a $0.14 per Mcf decrease in the gain on commodity derivative instruments resulting from the Company's hedging program. The notional amounts associated with these financial hedges represented approximately 55.0 Bcf of the Company's produced CBM sales volumes for the year ended December 31, 2016 at an average gain of $0.95 per Mcf. For the year ended December 31, 2015, these financial hedges represented approximately 57.5 Bcf at an average gain of $1.17 per Mcf.

Total exploration and production costs for the CBM segment were $189 million for the year ended December 31, 2016 compared to $209 million for the year ended December 31, 2015. The decrease in total dollars and decrease in unit costs for the CBM segment were due to the following items:

•CBM lease operating expense was $25 million for the year ended December 31, 2016 compared to $33 million for the year ended December 31, 2015. The decrease in total dollars was primarily related to a decrease in contractual services related to well tending, a decrease in repairs and maintenance expense, a decrease in employee related costs, and a decrease in salt water disposal costs. The decrease in unit costs was due to the decrease in total dollars, partially offset by the decrease in CBM gas sales volumes.

•CBM production, ad valorem, and other fees were $6 million for the year ended December 31, 2016 compared to $7 million for the year ended December 31, 2015. The $1 million decrease 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 positively impacted by the decrease in total average CBM sales price which was offset, in part, by the decrease in CBM gas sales volumes.

•CBM transportation, gathering and compression costs were $72 million for the year ended December 31, 2016 compared to $85 million for the year ended December 31, 2015. The $13 million decrease was primarily related to a decrease in repairs and maintenance, power and utilized firm transportation expense resulting from the decrease in CBM gas sales volumes. Unit costs were also positively impacted by the decrease in total dollars which was offset, in part, by the decrease in CBM gas sales volumes.

•Depreciation, depletion and amortization costs attributable to the CBM segment were $86 million for the year ended December 31, 2016 compared to $84 million for the year ended December 31, 2015. These amounts included depletion on a unit of production basis of $0.82 per Mcf and $0.73 per Mcf, respectively. The remaining depreciation, depletion and amortization costs were either recorded on a straight-line basis or related to gas well closing.

OTHER GAS SEGMENT

The Other Gas segment had a loss before income tax of $517 million for the year ended December 31, 2016 compared to a loss before income tax of $776 million for the year ended December 31, 2015.

	For the Years Ended December 31,			
	2016	2015	Variance	Percent Change
Other Gas Sales Volumes (Bcf)	21.7	24.7	(3.0)	(12.1)%
Oil Sales Volumes (Bcfe)*	0.4	0.5	(0.1)	(20.0)%
Total Other Sales Volumes (Bcfe)*	22.1	25.2	(3.1)	(12.3)%
Average Sales Price - Gas (Mcf)	$1.79	$2.03	$(0.24)	(11.8)%
Gain on Commodity Derivative Instruments - Cash Settlement- Gas (Mcf)	$0.75	$0.88	$(0.13)	(14.8)%
Average Sales Price - Oil (Mcfe)*	$6.23	$8.15	$(1.92)	(23.6)%
Total Average Other Sales Price (per Mcfe)	$2.61	$3.03	$(0.42)	(13.9)%
Average Other Lease Operating Expenses (per Mcfe)	0.69	0.90	(0.21)	(23.3)%
Average Other Production, Ad Valorem, and Other Fees (per Mcfe)	0.12	0.14	(0.02)	(14.3)%
Average Other Transportation, Gathering and Compression Costs (per Mcfe)	1.07	0.96	0.11	11.5 %
Average Other Depreciation, Depletion and Amortization Costs (per Mcfe)	1.49	2.34	(0.85)	(36.3)%
Total Average Other Costs (per Mcfe)	$3.37	$4.34	$(0.97)	(22.4)%
Average Margin for Other (per Mcfe)	$(0.76)	$(1.31)	$0.55	42.0 %

*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 also includes purchased gas activity, unrealized gain or loss on commodity derivative instruments, exploration and production related other costs, 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 the Chattanooga shale in Tennessee. Natural gas, NGLs and oil sales related to the Other Gas segment were $41 million for the year ended December 31, 2016 compared to $55 million for the year ended December 31, 2015. The decrease in natural gas and oil sales primarily related to the $0.24 per Mcf decrease in average gas sales price. Total exploration and production costs related to these other sales were $76 million for the year ended December 31, 2016 compared to $115 million for the year ended December 31, 2015. The decrease was primarily due to a decrease in depreciation, depletion and amortization costs related to the adjustment to the Company's shallow oil and gas rates after an impairment in the carrying value was recognized in the second quarter of 2015 (see Note 9 - Property, Plant and Equipment of the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information).

The Other Gas segment recognized an unrealized loss on commodity derivative instruments of $386 million as well as cash settlements of $17 million for the year ended December 31, 2016. For the year ended December 31, 2015, the Company recognized an unrealized gain on commodity derivative instruments of $197 million as well as cash settlements of $22 million. The unrealized loss/gain on commodity derivative instruments represents changes in the fair value of all of the Company's existing commodity hedges on a mark-to-market basis and is the 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.

Purchased gas volumes represent volumes of gas purchased at market prices from third-parties and then resold in order to fulfill contracts with certain customers. Purchased gas sales revenues were $43 million for the year ended December 31, 2016 compared to $14 million for the year ended December 31, 2015. Purchased gas costs were $43 million for the year ended December 31, 2016 compared to $11 million for the year ended December 31, 2015. The period-to-period increase in purchased gas sales revenue was due to the increase in purchased gas sales volumes, offset, in part, by the decrease in market prices.

	For the Years Ended December 31,			
	2016	2015	Variance	Percent Change
Purchased Gas Sales Volumes (in billion cubic feet)	21.7	6.8	14.9	219.1 %
Average Sales Price (per Mcf)	$ 1.99	$ 2.14	$ (0.15)	(7.0)%
Average Cost (per Mcf)	$ 1.97	$ 1.59	$ 0.38	23.9 %

Miscellaneous other income was $81 million for the year ended December 31, 2016 compared to $62 million for the year ended December 31, 2015. The $19 million increase was primarily due to the following items:

	For the Years Ended December 31,			
(in millions)	2016	2015	Variance	Percent Change
Right of Way Sales	$ 15	$ 2	$ 13	650.0 %
Equity in Earnings of Affiliates	52	47	5	10.6 %
Gathering Revenue	11	10	1	10.0 %
Other	3	3	—	— %
Total Miscellaneous Other Income	$ 81	$ 62	$ 19	30.6 %

- Right of Way Sales increased $13 million in the period-to-period comparison due to an initiative in the current year to generate additional revenue from our unutilized surface rights.
- Equity in Earnings of Affiliates increased $5 million primarily due to an increase in earnings from CONE Midstream Partners LP and CONE Gathering LLC. See Note 25 - Related Party Transactions of the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.

Gain on sale of assets was $14 million for the year ended December 31, 2016 compared to $13 million for the year ended December 31, 2015. The $1 million increase was due to various land asset sales that occurred throughout both periods, none of which were individually material.

Exploration and production related other costs were $15 million for the year ended December 31, 2016 compared to $10 million for the year ended December 31, 2015. The $5 million increase in costs is primarily related to the following items:

	For the Years Ended December 31,			
(in millions)	2016	2015	Variance	Percent Change
Lease Expiration Costs	$ 7	$ 4	$ 3	75.0 %
Permitting Expense	2	1	1	100.0 %
Land Rentals	4	5	(1)	(20.0)%
Other	2	—	2	100.0 %
Total Exploration and Other Costs	$ 15	$ 10	$ 5	50.0 %

- Lease Expiration Costs increased by $3 million in the period-to-period comparison, primarily due to an increase in the number of leases allowed to expire in the year ended December 31, 2016 as compared to the year ended December 31, 2015.

Other corporate expenses were $88 million for the year ended December 31, 2016 compared to $66 million for the year ended December 31, 2015. The $22 million increase in the period-to-period comparison was made up of the following items:

	For the Years Ended December 31,			
	2016	2015	Variance	Percent Change
Severance Expense	$1	$5	$(4)	(80.0)%
Litigation Settlements	1	2	(1)	(50.0)%
Insurance Expense	3	3	—	— %
Unutilized Firm Transportation and Processing Fees	37	33	4	12.1 %
Transaction Fees	4	—	4	100.0 %
Idle Rig Expense	33	19	14	73.7 %
Other	9	4	5	125.0 %
Total Other Corporate Expenses	$88	$66	$22	33.3 %

- Severance Expense decreased $4 million in the period-to-period comparison primarily due to the Company reorganization that occurred in the third quarter of 2015. Amounts recorded in the current period are primarily due to the Company's first quarter 2016 reorganization.
- 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 natural gas liquids. The increase in the period-to-period comparison was primarily due to the decrease in the utilization of capacity. The Company attempts to minimize this expense by releasing (selling) unutilized firm transportation capacity to other parties when possible and when beneficial. The revenue received when this capacity is released (sold) is included in Gathering Revenue in miscellaneous other income above.
- Transaction Fees of $4 million are associated with the dissolution of the Noble Energy Marcellus Shale joint venture.
- Idle Rig Expense related to temporary idling of some of the Company's natural gas rigs. The total idle rig expense increased in the period-to-period comparison due to unfavorable market conditions in the first half of the current period.
- Other increased $5 million in the period-to-period comparison primarily due to a 401(k) discretionary contribution in the current period, as well as various transactions that occurred throughout both periods, none of which were individually material.

Impairment of Exploration and Production Properties of $829 million for the year ended December 31, 2015 relates to the write down of the Company's shallow oil and gas asset values in June 2015. See Note 9- Property, Plant and Equipment of the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information. No such write downs occurred in the current period.
Selling, general and administrative (SG&A) costs are allocated to the total E&P segment based on percentage of total revenue and percentage of total projected capital expenditures. SG&A costs were $102 million for each of the years ended December 31, 2016 and December 31, 2015. Refer to the discussion of total company selling, general and administrative costs contained in the section "Net Loss Attributable to CONSOL Energy Shareholders" of this annual report for a detailed cost explanation.

Interest expense related to the E&P division was $3 million for the year ended December 31, 2016 compared to $6 million for the year ended December 31, 2015. Interest was incurred by the Other Gas segment on interest allocated to the E&P division under CONSOL Energy's credit facility.

TOTAL PA MINING OPERATIONS DIVISION ANALYSIS for the year ended December 31, 2016 compared to the year ended December 31, 2015:
The PA Mining Operations division principal activities consist of mining, preparation and marketing of thermal coal to power generators. The division also includes selling, general and administrative costs, as well as various other activities assigned to the PA Mining Operations division but not included in the cost components on a per unit basis.

The PA Mining Operations division had earnings before income tax of $131 million for the year ended December 31, 2016, compared to earnings before income tax of $405 million for the year ended December 31, 2015. Variances are discussed below.

(in millions)	For the Years Ended December 31, 2016	2015	Variance
Sales:			
Coal Sales	$1,066	$1,289	$ (223)
Freight Revenue	46	20	26
Miscellaneous Other Income	13	4	9
Total Revenue and Other Income	1,125	1,313	(188)
Operating Costs and Expenses:			
Operating Costs	691	789	(98)
Depreciation, Depletion and Amortization	154	167	(13)
Total Operating Costs and Expenses	845	956	(111)
Other Costs and Expenses:			
Other Costs	42	(122)	164
Depreciation, Depletion and Amortization	14	10	4
Total Other Costs and Expenses	56	(112)	168
Freight Expense	46	20	26
Selling, General and Administrative Costs	38	41	(3)
Total PA Mining Operations Costs	985	905	80
Interest Expense	9	3	6
Total PA Mining Operations Division Expense	994	908	86
Earnings Before Income Tax	$131	$405	$ (274)

The PA Mining Operations coal revenue and cost components on a per unit basis for these periods were as follows:

	For the Years Ended December 31, 2016	2015	Variance	Percent Change
Company Produced PA Mining Operations Tons Sold (in millions)	24.6	22.9	1.7	7.4 %
Average Sales Price Per PA Mining Operations Ton Sold	$43.31	$56.36	$(13.05)	(23.2%)
Total Operating Costs Per Ton Sold	$28.09	$34.47	$(6.38)	(18.5%)
Total Depreciation, Depletion and Amortization Costs Per Ton Sold	6.26	7.31	(1.05)	(14.4%)
Total Costs Per PA Mining Operations Ton Sold	$34.35	$41.78	$(7.43)	(17.8%)
Average Margin Per PA Mining Operations Ton Sold	$8.96	$14.58	$(5.62)	(38.5%)

Coal Sales

PA Mining Operations coal sales were $1,066 million for the year ended December 31, 2016, compared to $1,289 million for the year ended December 31, 2015. The $223 million decrease was attributable to a $13.05 per ton lower average sales price, offset by a 1.7 million increase in tons sold. The lower average sales price per PA Mining Operations ton sold was primarily the result of the continued decline in both the domestic and global thermal coal markets, particularly in the first half of 2016. The decline was related to higher customer inventories and lower gas prices after persistently mild 2015 weather.

The increase in overall tons sold reflects the improvement in both domestic and international coal demand throughout the second half of 2016.

Freight Revenue and Freight Expense

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 the Company contractually provides transportation services. Freight revenue is completely offset in freight expense. Freight revenue and freight expense were both $46 million for the year ended December 31, 2016, compared to $20 million for the year ended December 31, 2015. The $26 million increase was due to increased shipments where transportation services were contractually provided.

Miscellaneous Other Income

Miscellaneous other income was $13 million for the year ended December 31, 2016, compared to $4 million for the year ended December 31, 2015. Approximately $6 million of the increase was the result of a partial coal contract buyout in the current period. The remaining $3 million increase was the result of various transactions that occurred during both periods, none of which were individually material.

Operating Costs and Expenses

Operating costs and expenses are comprised of costs related to produced tons sold, along with changes in both the volumes and carrying values of coal inventory. Operating costs and expenses include items such as direct operating costs, royalty and production taxes, employee-related expenses and depreciation, depletion, and amortization costs. Total operating costs and expenses for the PA Mining Operations division were $845 million for the year ended December 31, 2016, or $111 million lower than the $956 million for the year ended December 31, 2015. Total costs per PA Mining Operations ton sold were $34.35 per ton in the year ended December 31, 2016, compared to $41.78 per ton in the year ended December 31, 2015. The decrease in the cost of coal sold was driven by the idling of one longwall at the PA Mining Operations complex for approximately 90 days, a reduction of staffing levels, vendor concessions and a realignment of employee benefits. All of the above steps resulted in more consistent operating schedules, reduced labor costs and improved productivity. Productivity for the year ended December 31, 2016, as measured by tons per employee hour, improved by 17% compared to the year earlier period, despite the reduced number of longwalls in operation.

Other Costs and Expenses

Other costs and expenses include items that are assigned to the PA Mining Operations division but are not included in unit costs. Other costs and expenses increased $168 million in the year ended December 31, 2016 compared to the year ended December 31, 2015. The increase was due to the following:

	For the Years Ended December 31,		
	2016	2015	Variance
OPEB Plan Changes	$—	$(129)	$ 129
Idle Mine Costs	19	—	19
Purchased Coal Costs	6	—	6
Litigation Expense	4	—	4
Severance Expense	1	—	1
Amortization of Capitalized Interest	9	9	—
Coal Reserve Holding Costs	4	5	(1)
Other	13	3	10
Other Costs and Expenses	$56	$(112)	$ 168

- Income of $129 million related to OPEB plan changes made in May 2015 for retired employees. Refer to the discussion of total Company long-term liabilities contained in the section "Net Loss Attributable to CONSOL Energy Shareholders" of this annual report for a detailed cost explanation. No such transactions occurred during the year ended December 31, 2016.
- Idle Mine Costs increased $19 million, due to the temporary idling of one longwall at the PA Mining Operations complex for approximately 90 days in the first half of 2016 to optimize operating schedules.

- Purchased Coal Costs increased $6 million due to higher volumes of coal that needed to be purchased to fulfill various contracts.
- Litigation expense relates to approximately $3 million of costs which were incurred during the year ended December 31, 2016 related to the proposed consent decree with respect to the Bailey mine complex. See Note 22 - Commitments and Contingent Liabilities of the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information. The remaining change was the result of various transactions that occurred, none of which were individually material.
- Severance Expense of $1 million was incurred during the year ended December 31, 2016 in connection with the Company's ongoing cost reduction efforts. No such transactions occurred in the prior period.
- Other increased $10 million in the period-to-period comparison primarily due to a 401(k) discretionary contribution in the current period.

Selling, General and Administrative Costs

Upon execution of the CNXC IPO, CNXC entered into a service agreement with CONSOL Energy that required CONSOL Energy to provide certain selling, general and administrative services. These services are paid monthly based on an agreed-upon fixed fee that is reset at least annually. See Note 25 - 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 selling, general and administrative costs related to PA Mining Operations was $38 million for the year ended December 31, 2016, compared to $41 million for the year ended December 31, 2015. Refer to the discussion of total Company selling, general and administrative costs contained in the section "Net Loss Attributable to CONSOL Energy Shareholders" of this annual report for a detailed cost explanation.

Interest Expense

Interest expense, net of amounts capitalized, of $9 million and $3 million for the years ended December 31, 2016 and 2015, respectively, is primarily comprised of interest on the CNXC revolving credit facility that was drawn upon after the CNXC IPO on July 7, 2015.

OTHER DIVISION ANALYSIS for the year ended December 31, 2016 compared to the year ended December 31, 2015:
The Other division includes expenses from various corporate and diversified business activities that are not allocated to the E&P or PA Mining Operations divisions. The diversified business activities include coal terminal operations, closed and idle mine activities, water operations, selling, general and administrative activities, income tax expense (benefit), as well as various other non-operated activities.

The Other division had a loss before income tax of $277 million for the year ended December 31, 2016, compared to a loss before income tax of $202 million for the year ended December 31, 2015. The Other division also includes total Company income tax expense related to continuing operations of $10 million for the year ended December 31, 2016, compared to an income tax benefit of $125 million for the year ended December 31, 2015.

	For the Years Ended December 31,			
(in millions)	2016	2015	Variance	Percent Change
Other Outside Sales	$32	$31	$ 1	3.2 %
Miscellaneous Other Income	73	78	(5)	(6.4)%
Gain on Sale of Assets	5	61	(56)	(91.8)%
Total Revenue	110	170	(60)	(35.3)%
Miscellaneous Operating Expense	183	79	104	131.6 %
Selling, General, and Administrative Costs	13	15	(2)	(13.3)%
Depreciation, Depletion and Amortization	12	20	(8)	(40.0)%
Loss on Debt Extinguishment	—	68	(68)	(100.0)%
Interest Expense	179	190	(11)	(5.8)%
Total Other Costs	387	372	15	4.0 %
Loss Before Income Tax	(277)	(202)	(75)	(37.1)%
Income Tax Expense (Benefit)	10	(125)	135	108.0 %
Net Loss	$(287)	$(77)	$ (210)	(272.7)%

Other Outside Sales
Other outside sales primarily consists of sales from the Company's coal terminal operations. Coal terminal operations sales were $32 million for the year ended December 31, 2016, compared to $31 million for the year ended December 31, 2015. The $1 million increase in the period-to-period comparison was primarily due to an increase in throughput rates in the current period.

Miscellaneous Other Income
Miscellaneous other income was $73 million for the year ended December 31, 2016, compared to $78 million for the year ended December 31, 2015. The change is due to the following items:

	For the Years Ended December 31,		
(in millions)	2016	2015	Variance
Equity in Earnings of Affiliates	$1	$ 8	$ (7)
Purchased Coal Sales	—	2	(2)
Rental Income	36	37	(1)
Interest Income	1	2	(1)
Right of Way Sales	12	8	4

Royalty Income	20	15	5
Other Income	3	6	(3)
Total Miscellaneous Other Income	$73	$ 78	$ (5)

- Equity in Earnings of Affiliates decreased $7 million due to the sale of the Company's 49% interest in Western Allegheny Energy in September 2015. 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.
- Purchased Coal Sales decreased $2 million due to lower volumes of coal that needed to be purchased to fulfill various contracts in the current period.
- Right of Way Sales increased $4 million in the period-to-period comparison due to an initiative in the current year to generate additional revenue from the Company's unutilized surface rights.
- Royalty Income increased $5 million primarily due to additional royalties received in the current year resulting from the sale of Buchanan Mine. 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.

Gain on Sale of Assets

Gain on sale of assets decreased $56 million in the period-to-period comparison, primarily due to the sale of the Company's 49% interest in Western Allegheny Energy in September 2015. 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.

Miscellaneous Operating Expense

Miscellaneous operating expense related to the Other division was $183 million for the year ended December 31, 2016, compared to $79 million for the year ended December 31, 2015. Miscellaneous operating expense increased in the period-to-period comparison due to the following items:

	For the Years Ended December 31,		
(in millions)	2016	2015	Variance
OPEB Plan Changes	$—	$(125)	$ 125
Coal Reserve Holding Costs	19	8	11
Litigation Expense	5	—	5
Pension Settlement	22	19	3
Bank Fees	18	17	1
Closed and Idle Mines	9	9	—
Purchased Coal	—	1	(1)
UMWA Expenses	9	10	(1)
Workers' Compensation	6	7	(1)
Lease Rental Expense	30	31	(1)
Coal Terminal Operations	18	20	(2)
UMWA OPEB Expense	43	47	(4)
Severance Payments	1	6	(5)
Industrial Supplies Working Capital Settlement	—	6	(6)
Pension Expense	(14)	6	(20)
Other	17	17	—
Miscellaneous Operating Expense	$183	$79	$ 104

- Income of $125 million 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 Attributable to CONSOL Energy Shareholders" of this annual report and Note 14 - Pension and Other Postretirement Benefit Plans in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for more information. No such transactions occurred in the current period.
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Coal Reserve Holding Costs increased $11 million in the period-to-period comparison, primarily as a result of the surrender of various leases in the current period.

- 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 14 - Pension and Other Postretirement Benefits Plans in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.
- Purchased Coal decreased $1 million due to lower volumes of coal that needed to be purchased to fulfill various contracts.
- Lease Rental Expense decreased $1 million primarily due to the buyout of certain leased equipment in the current period.

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- Coal Terminal Operations decreased $2 million due to a reduction in labor costs.
- UMWA OPEB Expense decreased $4 million primarily due to a decrease in interest costs.
- Severance Payments decreased $5 million in the period-to-period comparison, primarily related to the company reorganization that occurred in the year ended December 31, 2015.
- Industrial Supplies Working Capital Settlement of $6 million represents 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.
- Pension Expense decreased $20 million in the period-to-period comparison due to a decrease in actuarially-calculated amortization related to modifications made to the pension plan in May 2015. See Note 14 - Pension and Other Postretirement Benefits Plans in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.

Selling, General and Administrative Costs

Selling, general and administrative costs allocated to the Other division were $13 million for the year ended December 31, 2016, compared to $15 million for the year ended December 31, 2015. Refer to the discussion of total Company selling, general and administrative costs contained in the section "Net Loss Attributable to CONSOL Energy Shareholders" of this annual report for more information.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization decreased $8 million in the period-to-period comparison, primarily related to a reduction of the asset retirement obligations at various closed and idled mine locations.

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 2021 at an average price equal to 105.0% of the principal amount. No such transactions occurred in the current period.

Interest Expense

Interest expense of $179 million was recognized in the year ended December 31, 2016, compared to $190 million in the year ended December 31, 2015. The $11 million decrease in the period-to-period comparison was due to the partial payoff of the 2020 and 2021 bonds in March and April 2015. Also contributing to the decrease was a decrease in the average outstanding balance on the Company's revolving credit facility, as well as lower interest rates on the 2023 bonds issued in March 2015 when compared to the interest rate on the 2020 bonds.

Income Taxes

The effective income tax rate for continuing operations when excluding non-controlling interest was (1.9)% for the year ended December 31, 2016, compared to 26.3% for the year ended December 31, 2015. During the year ended December 31, 2016, CONSOL Energy settled a Federal audit of the years 2010-2013 and received a favorable private letter ruling from the IRS related to bonus depreciation. Overall, the Company received approximately $21 million in refunds during 2016 and anticipates additional cash refunds in 2017.

Some of the factors contributing to these refunds put pressure on deferred tax assets related to AMT credits. Although these credits never expire, at December 31, 2016, management could not demonstrate sufficient positive evidence to ensure realizability of these assets in the foreseeable future. As CONSOL Energy was in a three-year cumulative pre-tax loss, the Company did not consider future generation of income to support the realization of these credits. As a result, the Company recorded a valuation allowance of $167 million at December 31, 2016. These credits can be fully utilized when sufficient operating income is generated by the Company.

An additional $38 million valuation allowance was recorded against state deferred tax assets related to state net operating losses and other temporary differences, Federal charitable contribution and foreign tax credit carryforwards. See Note 6-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,			
	2016	2015	Variance	Percent Change
Total Company Loss Before Income Tax excluding Noncontrolling Interest	$(535)	$(476)	$(59)	12.4 %
Income Tax Expense (Benefit)	$10	$(125)	$135	(108.0)%
Effective Income Tax Rate	(1.9)%	26.3 %	(28.2)%	

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 per diluted share of $1.64, for the year ended December 31, 2015, compared to net income attributable to CONSOL Energy shareholders of $163 million, or earnings of $0.70 per diluted share, for the year ended December 31, 2014.

	For the Years Ended December 31,		
(Dollars in thousands)	2015	2014	Variance
(Loss) Income from Continuing Operations	$(350,266)	$164,947	$(515,213)
Loss from Discontinued Operations	(14,209)	(1,857)	(12,352)
Net (Loss) Income	$(364,475)	$163,090	$(527,565)
Less: Net Income Attributable to Noncontrolling Interests	10,410	—	10,410
Net (Loss) Income Attributable to CONSOL Energy Shareholders	$(374,885)	$163,090	$(537,975)

CONSOL Energy consists of two principal business divisions: Exploration and Production (E&P) and Pennsylvania (PA) Mining Operations. The E&P division includes four reportable segments: Marcellus, Utica, Coalbed Methane (CBM) and Other Gas.

The 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 2015 net loss before income tax was a 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 depressed NYMEX forward strip prices (see Note 9 - Property, Plant and Equipment of the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information).

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

The E&P division natural gas, NGLs, and oil sales were $729 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 46.0% decrease in the average Gas sales price per Mcf without the impact of derivative instruments, offset in part, by the 39.5% increase in total E&P sales volumes. The decrease in average sales price was the result of the overall decrease in general market prices.

The E&P division sales volumes, average sales price (including the effects of derivative instruments), and average costs for all active E&P operations were as follows:

	For the Years Ended December 31,			
	2015	2014	Variance	Percent Change
E&P Sales Volumes (Bcfe)	328.7	235.7	93.0	39.5 %
Average Sales Price (per Mcfe)	$2.81	$4.37	$(1.56)	(35.7)%
Average Costs (per Mcfe)	2.62	3.13	(0.51)	(16.3)%
Average Margin	$0.19	$1.24	$(1.05)	(84.7)%

Changes in the average costs per Mcfe were primarily related to the following items:

- The improvement in unit costs is primarily due to the continuing shift towards lower cost Marcellus and Utica Shale production, ongoing cost reduction efforts and the 39.5% increase in total volumes sold in the period-to-period comparison. Marcellus production made up 52.4% of E&P 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 E&P 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 per-unit basis primarily due to the adjustment to the Company's shallow oil and gas rates following the impairment in carrying value that was recognized in the second quarter of 2015 (see Note 9 - Property, Plant and Equipment in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for more information), as well as the increase in E&P sales volumes from the Company's lower cost Marcellus and Utica production. The decrease was offset, in part, by an overall increase in rates due to the reduction in the 2015 year-end reserves, as well as an increase in total dollars as production continued to grow.
- Lease operating expenses decreased on a per-unit basis in the period-to-period comparison due to the overall increase in E&P sales volumes. The decrease in unit costs was partially offset by an increase in repairs and maintenance, salt water disposal costs, and contractual services related to well tending.

The PA Mining Operations division had earnings before income tax of $405 million for the year ended December 31, 2015, compared to earnings before income tax of $431 million for the year ended December 31, 2014.

Sales tons, average sales price and average cost of goods sold per ton for the PA Mining Operations division were as follows:

	For the Years Ended December 31,			
	2015	2014	Variance	Percent Change
Company Produced PA Mining Operations Tons sold (in millions)	22.9	26.1	(3.2)	(12.3)%
Average Sales Price per ton sold	$56.36	$61.88	$(5.52)	(8.9)%
Average Cost of Goods Sold per ton	41.78	43.63	(1.85)	(4.2)%
Average Margin	$14.58	$18.25	$(3.67)	(20.1)%

The lower average sales price per ton sold in the 2015 period was primarily the result of the continued decline in both the domestic and global thermal coal markets. Due to the weak domestic thermal spot market, the PA Mining Operations division priced 5.5 million tons on the export market for the year ended December 31, 2015, compared to 3.3 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 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 Mining 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 Pension and OPEB plan modifications for active employees in

September 2014. Refer to the discussion of total Company long-term liabilities below 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 PA Mining Operations divisions, income taxes, and industrial supplies activity (this subsidiary was sold in December 2014). The Other division had a net loss of $77 million for the year ended December 31, 2015, compared to a net loss of $452 million for the year ended December 31, 2014.
Selling, general and administrative (SG&A) costs are allocated to the PA Mining Operations division based upon a shared service agreement that CONSOL Energy entered into with CNX Coal Resources LP (CNXC) upon execution of the CNXC initial public offering (IPO). The shared service agreement calls for CONSOL Energy to provide certain selling, general and administrative services that are paid for monthly, based on an agreed upon fixed fee that is reset at least annually. See Note 25 - Related Party Transactions of the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information. The remaining SG&A costs are allocated between the E&P and Other divisions based primarily on a percentage of total revenue and a percentage of total projected capital expenditures.

SG&A costs are excluded from the E&P and PA Mining Operations unit costs above. SG&A costs were $158 million for the year ended December 31, 2015, compared to $211 million for the year ended December 31, 2014. SG&A costs decreased due to the following items:

	For the Years Ended December 31,			
(in millions)	2015	2014	Variance	Percent Change
Short-Term Incentive Compensation	$40	$55	$ (15)	(27.3)%
Stock-Based Compensation	25	40	(15)	(37.5)%
Contributions	1	9	(8)	(88.9)%
Employee Wages and Related Expenses	62	70	(8)	(11.4)%
Consulting and Professional Services	15	20	(5)	(25.0)%
Advertising and Promotion	7	7	—	— %
Rent	8	8	—	— %
Other	—	2	(2)	(100.0)%
Total Company Selling, General and Administrative Expense	$158	$211	$ (53)	(25.1)%

- The decrease in Short-Term Incentive Compensation was a result of lower payouts in the current period.
- Stock-Based Compensation decreased $15 million in the period-to-period comparison primarily due to accelerated non-cash amortization recorded in the prior period for employees who received awards under the Company's Equity Incentive Plan.
- Contributions decreased $8 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 $2 million decrease is due to various transactions that occurred throughout both periods, none of which were individually material.
- Employee Wages and Related Expenses decreased $8 million primarily due to the Company reorganization that occurred in the year ended December 31, 2015.
- Consulting and Professional Services decreased $5 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.

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 the segments based upon criteria specific to each liability. Total CONSOL Energy continuing operations expense related to actuarial liabilities was income of

$162 million for the year ended December 31, 2015, compared to expense of $96 million for the year ended December 31, 2014. The decrease of $258 million was primarily due to modifications made to the OPEB and Pension plans in September 2014 and May 2015. 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. See Note 14—Pension and Other Postretirement Benefit Plans and Note 15—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.

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				
(in millions)	Marcellus	Utica	CBM	Other Gas	Total E&P	Marcellus	Utica	CBM	Other Gas	Total E&P
Natural Gas, NGLs and Oil Sales	$379	$93	$202	$55	$729	$(78)	$6	$(141)	$(66)	$(279)
Gain on Commodity Derivative Instruments	101	6	67	219	393	86	5	63	216	370
Purchased Gas Sales	—	—	—	14	14	—	—	—	5	5
Miscellaneous Other Income	—	—	—	62	62	—	—	—	2	2
Gain on Sale of Assets	—	—	—	13	13	—	—	—	(33)	(33)
Total Revenue and Other Income	480	99	269	363	1,211	8	11	(78)	124	65
Lease Operating Expense	44	22	33	23	122	(2)	4	(9)	(10)	(17)
Production, Ad Valorem, and Other Fees	18	2	7	3	30	—	1	(5)	(5)	(9)
Transportation, Gathering and Compression	200	35	85	23	343	96	28	(11)	(9)	104
Depreciation, Depletion and Amortization	162	59	84	66	371	30	41	(5)	(19)	47
Exploration and Production Related Other Costs	—	—	—	10	10	—	—	—	(13)	(13)
Purchased Gas Costs	—	—	—	11	11	—	—	—	4	4
Other Corporate Expenses	—	—	—	66	66	—	—	—	19	19
Impairment of Exploration and Production Properties	—	—	—	829	829	—	—	—	829	829
Selling, General and Administrative Costs	—	—	—	102	102	—	—	—	(27)	(27)
Total Exploration and Production Costs	424	118	209	1,133	1,884	124	74	(30)	769	937
Interest Expense	—	—	—	6	6	—	—	—	(3)	(3)
Total E&P Division Costs	424	118	209	1,139	1,890	124	74	(30)	766	934
Earnings (Loss) Before Income Tax	$56	$(19)	$60	$(776)	$(679)	$(116)	$(63)	$(48)	$(642)	$(869)

MARCELLUS SEGMENT

The Marcellus segment had earnings before income tax of $56 million for the year ended December 31, 2015 compared to earnings before income tax of $172 million for the year ended December 31, 2014.

	For the Years Ended December 31,			
	2015	2014	Variance	Percent Change
Marcellus Gas Sales Volumes (Bcf)	149.4	99.4	50.0	50.3 %
NGLs Sales Volumes (Bcfe)*	[illegible]	[illegible]		