CNX Resources Corp
Form 10-K
February 07, 2019

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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, 2018
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

CNX Resources Corporation
(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.)**

CNX Center
1000 CONSOL Energy Drive Suite 400
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, if any, every Interactive Data File required to be submitted 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 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, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company, " and "emerging growth 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 Emerging Growth Company o

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. 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, 2018, 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 $1,652,490,069.

The number of shares outstanding of the registrant's common stock as of January 18, 2019 is 198,335,252 shares.

DOCUMENTS INCORPORATED BY REFERENCE:

Portions of CNX's Proxy Statement for the Annual Meeting of Shareholders to be held on May 29, 2019, 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.
BBtu - billion British Thermal units.
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.
Tcfe - One trillion 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 process.
net - “net” natural gas or “net” acres are determined by adding the fractional ownership working interests the Company has in gross wells or acres.
TIL - turn-in-line; a well turned to sales.
blending - process of mixing dry and damp gas in order to meet downstream pipeline specifications.
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 (PDPs) - 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.
development well - a well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.
exploratory well - a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well or a stratigraphic test well.
gob well - a well drilled or vent hole converted to a well which produces or is capable of producing coalbed methane or other natural gas from a distressed zone created above and below a mined-out coal seam by any prior full seam extraction of the coal.
service well - a well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include, among other things, gas injection, water injection and salt-water disposal.
play - a proven geological formation that contains commercial amounts of hydrocarbons.

royalty interest - the land owner's share of oil or gas production, typically 1/8.
throughput - the volume of natural gas transported or passing through a pipeline, plant, terminal, or other facility during a particular period.
working interest - an interest that gives the owner the right to drill, produce and conduct operating activities on a property and receive a share of any production.
wet gas - natural gas that contains significant heavy hydrocarbons, such as propane, butane and other liquid hydrocarbons.

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 Securities Exchange Act of 1934, as amended (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,” “e “plan,” “predict,” “project,” "will," or their negatives, or other 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:

- prices for natural gas and natural gas liquids are volatile and can fluctuate widely based upon a number of factors beyond our control including oversupply relative to the demand for our products, weather and the price and availability of alternative fuels;
- our dependence on gathering, processing and transportation facilities and other midstream facilities owned by CNX Midstream Partners LP (NYSE: CNXM) (CNXM) and others;
- uncertainties in estimating our economically recoverable natural gas reserves, and inaccuracies in our estimates;
- the high-risk nature of drilling and developing natural gas wells;
- our identified drilling locations are scheduled out over multiple years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling;
- challenges associated with strategic determinations, including the allocation of capital and other resources to strategic opportunities;
- our development and exploration projects, as well as CNXM’s midstream system development, require substantial capital expenditures;
- 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 for our securities;
- environmental regulations can increase costs and introduce uncertainty that could adversely impact the market for natural gas with potential short and long-term liabilities;
- our operations are subject to operating risks that could increase our operating expenses and decrease our production levels which could adversely affect our results of operation and our 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;
- decreases in the availability of, or increases in the price of, required personnel, services, equipment, parts and raw materials in sufficient quantities or at reasonable costs to support our operations;
- if natural gas prices decrease or drilling efforts are unsuccessful, we may be required to record write-downs of our proved natural gas properties;
- changes in assumptions impacting management’s estimates of future financial results as well as other assumptions such as movement in our stock price, weighted-average cost of capital, terminal growth rates and industry multiples,

could cause goodwill and other intangible assets we hold to become impaired and result in material non-cash charges to earnings;

- a loss of our competitive position because of the competitive nature of the natural gas industry, consolidation within the industry or overcapacity in the industry adversely affecting our ability to sell our products and midstream services, which could impair our profitability;
- deterioration in the economic conditions in any of the industries in which our customers operate, a domestic or worldwide financial downturn, or negative credit market conditions;
- hedging activities may prevent us from benefiting from price increases and may expose us to other risks;
- existing and future government laws, regulations and other legal requirements and judicial decisions that govern our business may increase our costs of doing business and may restrict our operations;
- significant costs and liabilities may be incurred as a result of pipeline operations and related increase in the regulation of gas gathering pipelines;

- our ability to find adequate water sources for our use in shale gas drilling and production operations, or our ability to dispose of, transport or recycle water used or removed in connection with our gas operations at a reasonable cost and within applicable environmental rules;
- failure to find or acquire economically recoverable natural gas reserves to replace our current natural gas reserves;
- risks associated with our debt;
- a decrease in our borrowing base, which could decrease for a variety of reasons including lower natural gas prices, declines in natural gas proved reserves, asset sales and lending requirements or regulations;
- changes in federal or state income tax laws;
- cyber-incidents could have a material adverse effect on our business, financial condition or results of operations;
- construction of new gathering, compression, dehydration, treating or other midstream assets by CNXM may not result in revenue increases and may be subject to regulatory, environmental, political, legal and economic risks;
- our success depends on key members of our management and our ability to attract and retain experienced technical and other professional personnel;
- terrorist activities could materially and adversely affect our business and results of operations;
- we may operate a portion of our business with one or more joint venture partners or in circumstances where we are not the operator, which may restrict our operational and corporate flexibility and we may not realize the benefits we expect to realize from a joint venture;
- acquisitions and divestitures we anticipate may not occur or produce anticipated benefits;
- the outcomes of various legal proceedings, including those which are more fully described in our reports filed under the Exchange Act;
- there is no guarantee that we will continue to repurchase shares of our common stock under our current or any future share repurchase program at levels undertaken previously or at all;
- negative public perception regarding our industry could have an adverse effect on our operations;
- CONSOL Energy may not be able to satisfy its indemnification obligations in the future and such indemnities may not be sufficient to hold us harmless from the full amount of liabilities for which CONSOL Energy will be allocated responsibility;
- the separation of CONSOL Energy could result in substantial tax liability; and
- other factors discussed in this 2018 Form 10-K under “Risk Factors,” as updated by any subsequent Forms 10-Q, which are on file with the Securities and Exchange Commission.

PART I

ITEM 1. Business

General

CNX Resources Corporation (CNX or the Company) is a premiere independent oil and gas company that is focused on the exploration, development, production, gathering, processing and acquisition of natural gas properties primarily in the Appalachian Basin. Our operations are centered on unconventional shale formations, primarily the Marcellus Shale and Utica Shale.

CNX was incorporated in Delaware in 1991 under the name CONSOL Energy Inc. (CONSOL Energy), but its predecessors had been mining coal, primarily in the Appalachian Basin, since 1864. CNX entered the natural gas business in the 1980s initially to increase the safety and efficiency of its Virginia coal mines by capturing methane from coal seams prior to mining, which makes the mining process safer and more efficient. The natural gas business grew from the 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.

On November 28, 2017, CNX completed the tax-free spin-off of its coal business resulting in two independent, publicly traded companies: CONSOL Energy, a coal company, formerly known as CONSOL Mining Corporation; and CNX, a natural gas exploration and production company. As a result of the separation of the two companies, CONSOL Energy and its subsidiaries now hold the coal assets previously held by CNX, including its Pennsylvania Mining Complex, Baltimore Marine Terminal, its direct and indirect ownership interest in CONSOL Coal Resources LP, formerly known as CNXC Coal Resources LP, and other related coal assets previously held by CNX. The coal company, previously reported as the Company's Pennsylvania Mining Operations division, has been reclassified in the Audited Consolidated Financial Statements in Item 8 of this Annual Report on Form 10-K (the Form 10-K) to discontinued operations in 2017 as well as all prior periods presented.

CNX operates, develops and explores for natural gas in Appalachia (Pennsylvania, West Virginia, Ohio, and Virginia). Our primary focus is the continued development of our Marcellus Shale acreage and delineation and development of our unique Utica Shale acreage and stacked pay opportunity set. We believe that our concentrated operating area, our legacy surface acreage position, our regional operating expertise, our extensive data set from development, as well as from non-operated participation wells and our held-by-production acreage position provides us a significant competitive advantage over our competitors. Over the past ten years, CNX's natural gas production has grown by approximately 570% to produce a total of 507.1 net Bcfe in 2018, which includes approximately 27 Bcfe of production related to assets that were sold during the year. For additional information, see Note 6 - Acquisitions and Dispositions in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K and incorporated herein.

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 539,000 net acres in the Marcellus Shale and approximately 627,000 net acres that have Utica Shale potential in Ohio, West Virginia, and Pennsylvania. We also have approximately 2.5 million net acres in our coalbed methane play.

Highlights of our 2018 production include the following:
- Total average production of 1,389,325 Mcfe per day;
- 92% Natural Gas, 8% Liquids; and
- 57% Marcellus, 30% Utica, 12% coalbed methane, and 1% other.

At December 31, 2018, our proved natural gas, NGL, condensate and oil reserves (collectively, "natural gas reserves") had the following characteristics:

- 7.9 Tcfe of proved reserves;
- 94.4% natural gas;
- 57.0% proved developed;
- 98.6% operated; and
- A reserve life ratio of 15.54 years (based on 2018 production).

The following map provides the location of CNX's E&P operations by region:
CNX defines itself through its core values which serve as the compass for our road map and guide every aspect of our business as we strive to achieve our corporate mission:

- Responsibility: Be a safe and compliant operator; be a trusted community partner and respected corporate citizen; act with pride and integrity;
- Ownership: Be accountable for our actions and learn from our outcomes, both positive and negative; be calculated risk-takers and seek creative ways to solve problems; and
- Excellence: Be prudent capital allocators; be a lean, efficient, nimble organization; be a disciplined, reliable, performance-driven company.

These values are the foundation of CNX's identity and are the basis for how management defines continued success. We believe CNX's rich resource base, coupled with these core values, allows management to create value for the long-term. The U.S. electric power industry generates more than half of its output by burning fossil fuels. We believe that the use of natural gas as one of the principal fuel sources for electricity in the United States will continue for many years; in fact, the Energy Information Agency (EIA) forecasts that U.S. electricity generation from natural gas will increase by 40% by 2030 and by more than 50% by 2040. Natural gas is the dominant choice for space and water heating fuel in the U.S. domestic residential sector, and EIA forecasts gas consumption for this use to increase modestly over the next decades. Plentiful natural gas is also creating growing opportunities as feedstock for chemicals, plastics, and fertilizer manufacturing in the U.S. and for rapidly expanding exports, as the U.S. becomes a net exporter of the fuel. Additionally, we believe that, as both worldwide economies and U.S. export facilities expand, the demand for our natural gas will grow as well.

CNX's Strategy

CNX's strategy is to increase shareholder value through the development and growth of its existing natural gas assets and selective acquisition of natural gas and NGL acreage leases within its footprint. Our mission is to empower our team to embrace and drive innovative change that creates long-term per share value for our investors, enhances our communities and delivers energy solutions for today and tomorrow. We will also continue to focus on the monetization of non-core assets to accelerate value creation and to minimize any shortfall between operating cash flows and our growth capital requirements.

We expect natural gas to continue to be the dominant contributor to the domestic electricity generation mix, while fueling industrial growth in the U.S. economy. EIA forecasts that natural gas will be the single dominant fuel (including renewables and nuclear as “fuels”) for electricity generation out through 2050, and that total domestic natural gas consumption will increase 19% in that time. The Gas Exporting Countries Forum (GECF) forecasts global demand for gas to increase by 46% to 5.43 trillion cubic meters by 2040, according to the "Global Gas Outlook 2040". It also stated that generating electricity and the industrial sector will contribute the most to the growing demand and that the share of natural gas in the global energy balance will increase from 22% to 26% by 2040. With the recent growth of natural gas exports to Mexico and Canada, the United States becoming a net exporter of natural gas, and increasing liquefied natural gas (LNG) demand, we expect new markets to open in the coming years. We believe that our growth in natural gas production, our low drilling and operating costs, our leverage and liquidity positions, and our vast acreage will allow CNX to take advantage of these markets.

CNX's Capital Expenditure Budget

In 2019, CNX expects capital expenditures of approximately $1,000-$1,080 million. The 2019 budget includes $575-$625 million of drilling and completion ("D&C") capital and approximately $175 million of capital associated with land, midstream, and water infrastructure and $250-$280 million of capital for CNX Midstream Partners LP ("CNXM"). The company continuously evaluates multiple factors to determine incremental activity throughout the year, and as such may update guidance accordingly.

DETAIL OPERATIONS

Our 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 539,000 net Marcellus Shale acres at December 31, 2018.

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 approximately 45,000 acres of incremental Upper Devonian acres; however, these acres have historically not been disclosed separately as they generally coincide with our Marcellus acreage.

On January 3, 2018, the Company acquired the remaining 50% membership interest in CONE Gathering LLC (which has since been renamed CNX Gathering LLC), which holds the general partner interest and incentive distribution rights in CNXM, the entity that constructs and operates the gathering system for most of our Marcellus shale production. 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 627,000 net Utica Shale acres at December 31, 2018. Approximately 356,000 Utica acres coincide with Marcellus Shale acreage in Pennsylvania, West Virginia, and Ohio. During the third quarter of 2018, CNX closed on the sale of substantially all of its Ohio Utica Joint Venture Assets, including approximately 35,000 net acres in the wet gas Utica Shale areas of Belmont, Guernsey, Harrison, and Noble Counties (See Note 6 - Acquisitions and Dispositions in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for more information).

Coalbed Methane (CBM)

We have the rights to extract CBM in Virginia from approximately 308,000 net CBM acres in Central Appalachia. We produce CBM natural gas primarily from the Pocahontas #3 seam and still have a nominal drilling program.

We also have the rights to extract CBM from approximately 2,100,00 net CBM acres in other states including West Virginia, Pennsylvania, Ohio, Illinois, Indiana and New Mexico with no current plans to drill CBM wells in these areas.

Other Gas

We have the rights to extract natural gas from other shale and shallow oil and gas positions primarily in Illinois, Indiana, New York, Ohio, Pennsylvania, Virginia, and West Virginia from approximately 968,000 net acres at December 31, 2018. 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. In March 2018, CNX Gas completed the sale of substantially all of its shallow oil and gas assets in Pennsylvania and West Virginia, including approximately 833,000 net acres (See Note 6 - Acquisitions and Dispositions in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for more information).

Summary of Properties as of December 31, 2018

	Marcellus Segment	**Utica Segment**	**CBM Segment**	**Other Gas Segment**	**Total**
Estimated Net Proved Reserves (MMcfe)	5,595,409	1,067,617	1,209,638	8,671	7,881,335
Percent Developed	54 %	49 %	77 %	100 %	57 %
Net Producing Wells (including oil and gob wells)	355	45	4,152	71	4,623
Net Acreage Position:					
Net Proved Developed Acres	42,853	12,090	231,415	3,244	289,602
Net Proved Undeveloped Acres	26,324	7,046	—	—	33,370
Net Unproved Acres(1)	515,073	252,473	2,227,764	965,118	3,960,428
Total Net Acres(2)	584,250	271,609	2,459,179	968,362	4,283,400

(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.

(2) Acreage amounts are only included under the target strata CNX 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 the 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, and our acreage rights and have 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, Ohio 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, 2018, the number of producing wells, developed acreage and undeveloped acreage:

	Gross	**Net(1)**
Producing Gas Wells (including gob wells)	6,453	4,623
Producing Oil Wells	149	1
Net Acreage Position:		
Proved Developed Acreage	289,602	289,602
Proved Undeveloped Acreage	33,370	33,370
Unproved Acreage	4,940,180	3,960,428
Total Acreage	5,263,152	4,283,400

(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.

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

	Gross Unproved Acres	Net Unproved Acres	Net Proved Undeveloped Acres
Held by production/fee	4,797,145	3,896,613	18,524
Expiration within 2 years	87,553	37,115	7,628
Expiration beyond 2 years	55,482	26,700	7,218
Total Acreage	4,940,180	3,960,428	33,370

The leases reflected above as Gross and 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 1% of our total net unproved acres and leases with expiration dates beyond two years represent approximately 1% of our total net unproved acres. 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, 2018, 2017 and 2016, we drilled 83.9, 90.0 and 36.0 net development wells, respectively. Gob wells and wells drilled by operators other than our primary joint venture partners at that time are excluded from net development wells. In 2018, there were 22.0 net development wells and no exploratory wells drilled but uncompleted. There were no dry development wells in 2018, 2017, or 2016. As of December 31, 2018, there are 8.0 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,		
	2018	2017	2016
Marcellus segment	65.9	9.0	—
Utica segment	12.0	17.0	13.0
CBM segment	6.0	64.0	23.0
Other Gas segment	—	—	—
Total Development Wells (Net)	83.9	90.0	36.0

Exploratory Wells (Net)

There were no exploratory wells drilled during the year ended December 31, 2018. There were 4.0 net exploratory wells drilled during the year ended December 31, 2017 and no exploratory wells drilled during the year ended December 31, 2016. As of December 31, 2018, there are 4.0 net exploratory wells in process. The following table illustrates the exploratory wells drilled by well classification type:

	For the Year Ended December 31,								
	2018			2017			2016		
	Producing	Dry	Still Eval.	Producing	Dry	Still Eval.	Producing	Dry	Still Eval.
Marcellus segment	—	—	—	—	—	—	—	—	—
Utica segment	—	—	—	4.0	—	—	—	—	—
CBM segment	—	—	—	—	—	—	—	—	—
Other Gas segment	—	—	—	—	—	—	—	—	—
Total Exploratory Wells (Net)	—	—	—	4.0	—	—	—	—	—

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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,		
	2018	**2017**	**2016**
Proved developed reserves	4,494,878	4,409,065	3,683,302
Proved undeveloped reserves	3,386,457	3,172,547	2,568,346
Total proved developed and undeveloped reserves(1)	7,881,335	7,581,612	6,251,648

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(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)		
	2018	**2017**	**2016**
Future net cash flows	$13,132	$7,841	$2,419
Total PV-10 measure of pre-tax discounted future net cash flows (1)	$6,172	$4,140	$1,559
Total standardized measure of after tax discounted future net cash flows	$4,655	$3,131	$955

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(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,		
	2018	2017	2016
	(Dollars in millions)		
Future cash inflows	$26,610	$19,262	$11,303
Future production costs	(7,730)	(7,234)	(5,851)
Future development costs (including abandonments)	(1,600)	(1,711)	(1,550)
Future net cash flows (pre-tax)	17,280	10,317	3,902
10% discount factor	(11,108)	(6,177)	(2,343)
PV-10 (Non-GAAP measure)	6,172	4,140	1,559
Undiscounted income taxes	(4,147)	(2,476)	(1,483)
10% discount factor	2,630	1,467	879
Discounted income taxes	(1,517)	(1,009)	(604)
Standardized GAAP measure	$4,655	$3,131	$955

Gas Production

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

	For the Year Ended December 31,		
	2018	2017	2016
Natural Gas			
Sales Volume (MMcf)			
Marcellus	255,127	209,687	186,812
Utica	148,117	70,708	71,277
CBM	60,268	65,373	68,971
Other	4,714	19,125	21,693
Total	468,226	364,893	348,753
NGL			
Sales Volume (Mbbls)			
Marcellus	5,227	4,604	3,922
Utica	853	1,851	2,787
Other	1	1	1
Total	6,081	6,456	6,710
Oil and Condensate			
Sales Volume (Mbbls)			
Marcellus	286	346	360
Utica	78	204	470
Other	35	39	65
Total	399	589	895
Total Sales Volume (MMcfe)			
Marcellus	288,203	239,387	212,504
Utica	153,704	83,038	90,820
CBM	60,268	65,373	68,971
Other	4,929	19,368	22,092
Total	507,104	407,166	394,387

***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.**

Note: 2018 production includes approximately 27 Bcfe of production related to assets that were sold during the year. For additional information, see Note 6 - Acquisitions and Dispositions in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K and incorporated herein.

CNX expects a minimum base for 2019 annual natural gas production volumes of 495-515 Bcfe, which equates to an approximately 5% annual increase, based on the midpoint of guidance, compared to 2018 volumes when excluding production from assets that were sold.

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 NGL production for the periods indicated. 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,		
	2018	**2017**	**2016**
Average Sales Price - Gas (Mcf)	$2.97	$2.59	$1.92
(Loss) Gain on Commodity Derivative Instruments - Cash Settlement- Gas (Mcf)	$(0.15)	$(0.11)	$0.70
Average Sales Price - NGLs (Mcfe)*	$4.55	$4.03	$2.42
Average Sales Price - Oil (Mcfe)*	$9.89	$7.56	$6.15
Average Sales Price - Condensate (Mcfe)*	$8.43	$6.59	$4.58
Total Average Sales Price (per Mcfe) Including Effect of Derivative Instruments	$2.97	$2.66	$2.63
Total Average Sales Price (per Mcfe) Excluding Effect of Derivative Instruments	$3.11	$2.76	$2.01
Average Lifting Costs Excluding Ad Valorem and Severance Taxes (per Mcfe)	$0.19	$0.22	$0.24
Average Sales Price - NGLs (Bbl)	$27.30	$24.18	$14.52
Average Sales Price - Oil (Bbl)	$59.34	$45.36	$36.90
Average Sales Price - Condensate (Bbl)	$50.58	$39.54	$27.48

***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 $0.14 per Mcfe, $0.17 per Mcfe, and $0.09 per Mcfe for 2018, 2017, and 2016, respectively, to average gas sales prices. CNX expects to continue to realize a liquids uplift benefit as additional wells are turned-in-line, primarily in the liquid-rich areas of the Marcellus shale. 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. Certain of CNX'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 356.3 Bcf of our produced gas sales volumes for the year ended December 31, 2018 at an average price of $2.76 per Mcf. The notional volumes associated with these gas swaps represented approximately 312.2 Bcf of our produced gas sales volumes for the year ended December 31, 2017 at an average price of $2.60 per Mcf. As of January 18, 2019, these physical and swap transactions represent approximately 376.0 Bcf of our estimated 2019 production at an average price of $2.71 per Mcf, 468.6 Bcf of our estimated 2020 production at an average price of $2.55 per Mcf, 410.3 Bcf of our estimated 2021 production at an average price of $2.44 per Mcf, approximately 276.6 Bcf of our estimated 2022 production at an average price of $2.48 per Mcf, and approximately 127.0 Bcf of our estimated 2023 production at an average price of $2.35 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

E&P Midstream Gas Services

CNX 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, overtime CNX has acquired extensive gathering assets. CNX now owns or operates approximately 2,500 miles of natural gas gathering pipelines as well as a number of natural gas processing facilities. These assets are part of the E&P Division (See Note 24 - Segment Information in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for more information).

CNX's Midstream Division (see below) owns substantially all of CNX's Marcellus Shale gathering systems. With respect to the Utica Shale, CNX primarily contracts with third-party gathering services.

CNX has developed a diversified portfolio of firm transportation capacity options to support its production growth plan. CNX plans to selectively acquire firm capacity on an as-needed basis, while minimizing transportation costs and long-term financial obligations. Optimization of our firm transportation portfolio may also include, from time to time and as appropriate, releasing firm transportation to others. CNX also benefits from the strategic location of our primary production areas in southwestern Pennsylvania, northern West Virginia, and eastern Ohio. These areas are currently served by a large concentration of major pipelines that provide us with access to major gas markets without the necessity of transporting our gas out of the region and it is expected that recently-approved and pending pipeline projects will increase the take-away capacity from our region. In addition to firm transportation capacity, CNX has developed a processing portfolio to support the projected volumes from its wet gas production areas and has the operational and contractual flexibility to potentially convert a portion of currently processed wet gas volumes to be marketed as dry gas volumes, or vice-versa, as economically appropriate.

CNX has the advantage of having natural gas production from CBM and lower Btu Utica wells in close proximity to higher Btu Marcellus wells. Separately, the low Btu CBM gas and the high Btu Marcellus gas may need processing in order to meet downstream pipeline specifications. However, the geographic proximity and interconnected gathering system servicing these wells allow CNX to blend this gas together and in some cases eliminate the need for the costly processing of gas that does not meet pipeline specification. These different gas types allow us more flexibility in bringing Marcellus and Utica shale wells on-line at qualities that meet interstate pipeline specifications.

Midstream Division

On January 3, 2018, CNX closed its previously announced acquisition of Noble Energy’s (Noble) 50% membership interest in CONE Gathering LLC, which holds the general partner interest and incentive distribution rights in CONE Midstream Partners LP. In conjunction with the closing, CONE Midstream Partners LP was renamed CNX Midstream Partners LP (CNX Midstream or CNXM) and CONE Gathering LLC was renamed CNX Gathering LLC (CNX Gathering) (See Note 6 - Acquisitions and Dispositions in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for more information). Also on January 3, 2018, the Company’s board of directors authorized CNX Midstream to enter into an amendment to its gas gathering agreement with CNX Gas Company LLC, a wholly-owned subsidiary of CNX.

CNX Gathering develops, operates and owns substantially all of CNX’s Marcellus Shale gathering systems. Prior to its acquisition of Noble’s interest, CNX accounted for its interest in CNX Gathering under the equity method of accounting. Subsequent to the acquisition, CNX is the single sponsor of CNXM, and beginning in the first quarter of 2018 CNX Gathering was consolidated into the Company’s financial statements as the Midstream Division (See Note 24 - Segment Information in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for more information. We believe that the network of right-of-ways, vast surface holdings, experience in building and operating gathering systems in the Appalachian basin, and increased control and flexibility will give CNX Gathering an advantage in building the midstream assets required to execute our Marcellus Shale development plan.

Natural Gas Competition

The United States natural gas industry is highly competitive. CNX competes with other large producers, as well as a myriad of smaller producers and marketers. CNX 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 14% of dry natural gas production during the first ten months of 2018. The EIA reported 485,383 producing natural gas wells in the United States at December 31, 2017 (the latest year for which government statistics are available), which is approximately 15% lower than 2016.

CNX expects natural gas to continue 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, natural gas represented 35% of U.S. electricity generation during the twelve months ended October 31, 2018, up from 32% in 2017. According to the EIA, from January through June of 2018, net natural gas exports from the United States averaged 0.87 billion cubic feet per day (Bcf/d), more than double the average daily net exports during all of 2017 (0.34 Bcf/d). The United States, which became a net natural gas exporter on an annual basis in 2016 for the first time in almost 60 years, has continued to export more natural gas than it imports for five of the first six months in 2018. U.S. natural gas exports have increased primarily with the addition of new LNG export facilities in the Lower 48 states. The EIA also states that U.S. exports of LNG through the first half of 2018 rose 58% compared with the same period in 2017. CNX 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. The EIA currently expects overall demand for U.S. natural gas in 2019 to increase 1.3% from 2018. CNX estimates 2019 in-basin (Ohio, West Virginia, and Pennsylvania) demand to increase by approximately 3% compared with 2018. Our increasing gas production will allow CNX to participate in growing markets.

CNX gas operations are primarily located in the eastern United States, specifically the Appalachian Basin. The gas market is highly fragmented and not dominated by any single producer. We believe that competition among producers is based primarily on acreage position, low drilling and operating costs as well as pipeline transportation availability to the various markets.

Continued demand for CNX's natural gas and the prices that CNX 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.

Non-Core Mineral Assets and Surface Properties

CNX owns significant natural gas assets that are not in our short-term 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.

Water Division

CNX Water Assets LLC (CNX Water) is a wholly-owned subsidiary of CNX and supplies turnkey solutions for water sourcing, delivery and disposal for our natural gas operations, and supplies solutions for water sourcing as well as delivery and disposal for third-parties. In coordination with our midstream operations, CNX Water 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, 2018, CNX had 564 employees, none of whom are subject to a collective bargaining agreement.

Industry Segments

Financial information concerning industry segments, as defined by accounting principles generally accepted in the United States, for the years ended December 31, 2018, 2017 and 2016 is included in Note 24 - Segment Information in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K and incorporated herein.

Financial Information about Geographic Areas

All of the Company's assets and operations are located in the continental United States.

Laws and Regulations

General

Our natural gas and midstream operations are subject to various federal, state and local (including county and municipal level) laws and regulations. These laws and regulations cover virtually every aspect of our operations including, among other things: use of public roads; construction of well pads, impoundments, tanks and roads; pooling and unitizations; water withdrawal and procurement for well stimulation purposes; well drilling, casing and hydraulic fracturing; stormwater management; well production; well plugging; venting or flaring of natural gas; pipeline construction and the compression and transmission of natural gas and liquids; reclamation and restoration of properties after natural gas operations are completed; handling, storage, transportation and disposal of materials used or generated by natural gas operations; the calculation, reporting and payment of taxes on gas production; and gathering of natural gas production. Numerous governmental permits, authorizations and approvals under these laws and regulations are required for natural gas and midstream operations. These laws and regulations, and the permits, authorizations and approvals issued pursuant to those laws and regulations, are intended to protect, among other things: air quality; ground water and surface water resources, including drinking water supplies; wetlands; waterways; endangered plants and wildlife; state natural resources and the health and safety of our employees and the communities in which we operate.

Additionally, the electric power generation industry, which consumes significant quantities of natural gas, remains subject to extensive regulation regarding the environmental impact of its power generation activities, which could impact demand for our natural gas.

We endeavor to conduct our natural gas and midstream 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 operations can and do occur. Such exceedances and violations generally result in fines or penalties but could make it more difficult for us to obtain necessary permits in the future. The possibility exists that new legislation or regulations may be adopted which would have a significant impact on our natural gas or midstream operations or on our customers' ability to use our natural gas and may require us or our customers to change their operations significantly or incur substantial costs. See “Risk Factors -- *Existing and future governmental laws, regulations and other legal requirements and judicial decisions that govern our business may increase our costs of doing business and may restrict our operations*” for additional discussion regarding additional laws and regulations affecting our business, operations and industry.

Environmental Laws

Many of the laws and regulations referred to above are state level environmental laws and regulations, which vary according to the state in which we are conducting operations. However, our natural gas and midstream operations are also subject to numerous federal level environmental laws and regulations.

In addition to routine reviews and inspections by regulators to confirm compliance with applicable regulatory requirements, CNX has established protocols for ongoing assessments to identify potential environmental exposures. These assessments take into account industry and internal best management practices and evaluate compliance with laws and regulations and include reviews of our third-party service providers, including, for instance, waste management facilities.

Hydraulic Fracturing Activities. Hydraulic fracturing is typically regulated by state oil and natural gas commissions and similar agencies, but the U.S. Environmental Protection Agency (“EPA”) has asserted certain regulatory authority over hydraulic fracturing and has moved forward with various regulatory actions, including the issuance of new regulations requiring green completions for hydraulically fractured wells, and has disclosed its intent to develop regulations to require companies to disclose information regarding the chemicals used in hydraulic fracturing. Some states, including states in which we operate, have adopted regulations that could impose more stringent disclosure and/or well construction requirements on hydraulic fracturing operations, or otherwise seek to ban some or all of these activities.

Scrutiny of hydraulic fracturing activities also continues in other ways. In June 2015, the EPA issued its draft report on the potential impacts of hydraulic fracturing on drinking water and groundwater. The draft report found no systemic negative impacts from hydraulic fracturing. In December 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 negative impacts from hydraulic fracturing, it also included the guidance to industry and regulators on how the process can be performed safely. We cannot predict whether any other legislation or regulations will be enacted and if so, what its provisions will be.

Clean Air Act. The federal Clean Air Act 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. Various activities in our operations are subject to regulation, including pipeline compression, venting and flaring of natural gas, and hydraulic fracturing and completion processes, as well as fugitive emissions from operations. We obtain permits, typically from state or local authorities, to conduct these activities. Additionally, 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. Further, some states and the federal government have proposed that emissions from certain proximate and related sources should be aggregated to provide for regulation and permitting of a single, major source. Federal and state governmental agencies continue to investigate the potential for emissions from oil and natural gas activities, and further regulation could increase our cost or temporarily restrict our ability to produce. For example, the EPA sets National Ambient Air Quality Standards for certain pollutants and such changes which could cause us to make additional capital expenditures or alter our business operations in some manner. See *"Risk Factors - Regulation of greenhouse gas emissions at the federal or state level may increase our operating costs and reduce the value of our natural gas assets and such regulation, as well as uncertainty concerning such regulation, could adversely impact the market for natural gas, as well as for our securities."* for additional discussion regarding certain laws and regulations related to air emissions and related matters.

Clean Water Act. The federal Clean Water Act ("CWA") and corresponding state laws affect our natural gas operations by regulating storm water or other regulated substance discharges, including pollutants, sediment, and spills and releases of oil, brine and other substances, into surface waters, and in certain instances imposing requirements to dispose of produced wastes and other oil and gas wastes at approved disposal facilities. The discharge of pollutants into jurisdictional waters is prohibited, except in accordance with the terms of a permit issued by the EPA, the U.S. Army Corps of Engineers, or a delegated state agency. These permits require regular monitoring and compliance with effluent limitations and reporting requirements govern the discharge of pollutants into regulated waters. Federal and state regulatory agencies can impose administrative, civil and/or criminal penalties for non-compliance with discharge permits or other requirements of the CWA and analogous state laws and regulations. See *"Risk Factors -Environmental regulations can increase costs and introduce uncertainty that could adversely impact the market for natural gas with potential short and long-term liabilities*." for additional discussion regarding certain laws and regulations related to clean water, the disposal or use of water and related matters.

Endangered Species Act. The Endangered Species Act and related state regulation protect plant and animal species that are threatened or endangered. Some of our operations are located in areas that are or may be designated as protected habitats for endangered or threatened species, including the Northern Long-Eared and Indiana bats, which has a seasonal impact on our construction activities and operations. New or additional species that may be identified as requiring protection or consideration may lead to delays in permits and/or other restrictions.

Safety of Gas Transmission and Gathering Pipelines. Natural gas pipelines serving our operations are subject to regulation by the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration ("PHMSA") pursuant to the Natural Gas Pipeline Safety Act of 1968, ("NGPSA"), as amended by the Pipeline Safety Act of 1992, the Accountable Pipeline Safety and Partnership Act of 1996, the Pipeline Safety Improvement Act of 2002 ("PSIA"), the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006, and the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (the "2011 Pipeline Safety Act"). The NGPSA regulates safety requirements in the design, construction, operation and maintenance of natural gas pipeline facilities, while the PSIA establishes mandatory inspections for all U.S. oil and natural gas transmission pipelines in high-consequence areas. Additionally, certain states, such as West Virginia, also maintain jurisdiction over intrastate natural gas lines. See "*Risk Factors -- We may incur significant costs and liabilities as a result of pipeline operations and related increase in the regulation of gas gathering pipelines*." for additional discussion regarding gas transmission and gathering pipelines.

Resource Conservation and Recovery Act. The federal Resource Conservation and Recovery Act (RCRA) and corresponding state laws and regulations affect natural gas operations by imposing requirements for the management, treatment, storage and disposal of hazardous and non-hazardous wastes, including wastes generated by natural gas operations. 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.

Federal Regulation of the Sale and Transportation of Natural Gas

Federal Energy Regulatory Commission. Regulations and orders issued 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 has jurisdiction over the transportation of natural gas in interstate commerce, and regulates the terms, conditions of service, and rates for the interstate transportation of our natural gas production. The FERC possesses regulatory oversight over natural gas markets, including anti-market manipulation regulation. The FERC has the ability to assess civil penalties, order disgorgement of profits and recommend criminal penalties for violations of the Natural Gas Act or the FERC's regulations and policies thereunder.

Section 1(b) of the Natural Gas Act exempts natural gas gathering facilities from regulation by the FERC. However, the distinction between federally unregulated gathering facilities and FERC-regulated transmission facilities is a fact-based determination, and the classification of facilities is the subject of ongoing litigation. 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.

Natural gas prices are currently unregulated, but Congress historically has been active in the area of natural gas regulation. We cannot predict whether new legislation to regulate natural gas sales might be enacted in the future or what effect, if any, any such legislation might have on our operations.

Health and Safety Laws

Occupational Safety and Health Act. Our natural 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. Additionally, OSHA's hazardous communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state laws require 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.

Climate Change Laws and Regulations

Climate change continues to be a legislative and regulatory focus. There are a number of proposed and final laws and regulations that limit greenhouse gas emissions, and regulations that restrict emissions could increase our costs should the requirements necessitate the installation new equipment or the purchase of emission allowances. These laws and regulations could also impact our customers, including the electric generation industry, making alternative sources of energy more competitive. Additional regulation could also lead to permitting delays and additional monitoring and administrative requirements, as well as to impacts on electricity generating operations. See *"Risk Factors - Regulation of greenhouse gas emissions at the federal or state level may increase our operating costs and reduce the value of our natural gas assets and such regulation, as well as uncertainty concerning such regulation, could adversely impact the market for natural gas, as well as for our securities."* for additional discussion regarding certain laws and regulations related to climate change, greenhouse gas and related matters.

Title to Properties

CNX acquires ownership or leasehold rights to oil and natural gas properties prior to conducting operations on those properties. The legal requirements of such ownership or leasehold rights generally are established by state statutory or common law. As is customary in the natural gas industry, we have generally conducted only a summary review of the title to oil and gas rights that are not yet 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. Prior to the commencement of development operations on natural gas and coalbed methane properties, we conduct a thorough title examination and perform curative work with respect to significant title defects. Our discovering title defects which we are unable to cure may adversely impact our ability to develop those properties and we may have to reduce our estimated gas reserves including our proved undeveloped reserves. In accordance with the foregoing, we have completed title work on substantially all of our natural gas and coalbed methane properties that are currently producing and believe that we have satisfactory title to our producing properties in accordance with standards generally accepted in the industry.

Available Information

CNX maintains a website at www.cnx.com. CNX makes available, free of charge, on this website our annual reports 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 Exchange Act, as soon as reasonably practicable after such reports are available, electronically filed with, or furnished to the SEC. Those reports 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 CNX” (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.

Prices for natural gas and NGLs are volatile and can fluctuate widely based upon a number of factors beyond our control, including oversupply relative to the demand for our products, weather and the price and availability of alternative fuels. An extended decline in the prices we receive for our natural gas and NGLs 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 and NGLs. Natural gas, NGLs, 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 disposition in 2017 of our entire coal operations has increased our exposure to fluctuations in the price of natural gas, NGLs, oil and condensate.

In particular, 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 have arguably recovered as of 2018, continued volatility remains a strong possibility.

Our producing properties are geographically concentrated in the Appalachian Basin, which exacerbates the impact of regional supply and demand factors on our business, including the pricing of our gas. The success of the Marcellus Shale and Utica Shale plays has resulted in growth in natural gas production in this region, with production per day in Pennsylvania, West Virginia and Ohio more than tripling since 2011. Not all of the natural gas produced in this region can be consumed by regional demand and must therefore be exported to other regions through pipelines. This export causes gas purchased and sold locally to be priced at a discount to many other market hubs, such as the benchmark Louisiana Henry Hub price. This discount, or negative basis, to the Henry Hub price is forecasted to continue in future years. While we expect many of the planned interstate pipeline projects to reduce this discount, it could widen further if these projects to move gas out of the basin are delayed or denied for any reason, such as permitting issues or environmental lawsuits.

An extended period of lower natural gas prices can negatively affect us in several other ways, including reduced cash flow, which decreases funds available for capital expenditures to replace reserves or increase production. Also, our access to other sources of capital, such as equity or long-term debt markets, could be severely limited or unavailable.

Our drilling plans also include some activity in areas of shale formations that may also contain NGLs, condensate and/or oil. The prices for NGLs, 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 NGLs has led to a decline of over 40% since 2014 in the uplift we receive, on an Mcf equivalent basis when excluding hedging impact, from NGLs. Our results of operations may be adversely affected by a continued depressed level of, or further downward fluctuations in, NGLs, 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:

- weather conditions in our markets that affect the demand for natural gas;
- changes in the consumption pattern of industrial consumers, electricity generators and residential users of electricity and natural gas;
- with respect to natural gas, the price and availability of alternative fuel sources used by electricity generators;
- technological advances affecting energy consumption and conservation measures reducing demand;
- the costs, availability and capacity of transportation infrastructure;
- proximity and capacity of natural gas pipelines and other transportation facilities;
- changes in levels of international demand and tariffs associated with international export; and

- the impact of domestic and foreign governmental laws and regulations, including environmental and climate change regulations and delays.

Our business depends on gathering, processing and transportation facilities and other midstream facilities owned by CNXM and others. The disruption of, capacity constraints in, or proximity to pipeline systems could limit sales of our natural gas and NGLs and cash flows from operations, and any decrease in availability of pipelines or other midstream facilities interconnected to third parties' or CNXM's gathering systems could adversely affect our operations or our investment in CNXM.

We gather, process and transport our natural gas to market by utilizing pipelines and facilities owned by others, including CNXM. 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 NGLs could be reduced, which could negatively affect 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 NGLs are reduced because of transportation or processing constraints, our revenues will be reduced and our unit costs will increase. If pipeline quality standards change or we cannot meet applicable standards, we might be required to install additional processing equipment which could increase our costs. Further, in some circumstances we need to meet predetermined specifications with respect to our blending of dry and damp gas; changes in the production mix could negatively impact our ability to efficiently meet our specified requirements. Pipelines 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 have a material adverse effect on our business, financial condition, results of operations and cash flows.

Further, a significant portion of our natural gas is sold on or through a single pipeline, Texas Eastern Transmission, which could experience capacity issues, operational disruptions and unexpected downtime. Any reduction in capacity on the Texas Eastern pipeline could result in curtailments and reduce our production of natural gas. A reduction in capacity could also reduce the demand for our natural gas, which would reduce the price we receive for our production.

In addition to our relationship with CNXM, we have various third-party firm transportation, natural gas processing, gathering and other agreements in place, many of which have minimum volume delivery commitments. We are obligated to pay fees on minimum volumes to our service providers regardless of actual volume throughput. Reductions in our drilling program may result in insufficient production to utilize our full firm transportation and processing capacity. 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.

Our investment in midstream infrastructure through CNXM is intended, among other items, to connect our wells to other existing gathering and transmission pipelines. Our infrastructure development and maintenance programs, through CNXM, can involve significant risks, including those relating to timing, cost overruns and operational efficiency, which risks can be further affected by other issues. For example, approximately 34% of our 2018 production flowed through CNXM's Majorsville and McQuay Stations. An operational issue at either of those stations would materially impact CNX's production, cash flow and results of operation. CNXM's assets connect to other pipelines or facilities owned and operated by unaffiliated third parties. The continuing operation of third-party pipelines, processing and fractionation plants, compressor stations and other midstream facilities is not within our or CNXM's control. These third-party pipelines, processing and fractionation plants, compressor stations and other midstream facilities may become unavailable because of testing, turnarounds, line repair, maintenance, changes to operating conditions, delivery or receipt parameters, unavailability of firm transportation, lack of operating capacity, force majeure events, regulatory requirements and curtailments of receipt or deliveries due to insufficient capacity or because of damage from severe weather conditions or other operational issues.

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

Natural gas reserves are economically recoverable when the price at which they are expected to be sold exceeds their expected cost of production and sales. Natural gas reserves require subjective estimates of underground accumulations of natural gas, and 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 prove to 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 to be 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 PV-10 measure of pre-tax discounted future net cash flows and the standardized measure of after tax discounted future net cash flows from our proved reserves included within this Annual Report on Form 10-K are 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;
- our acreage position, and our ability to acquire additional acreage, including third-party swaps to develop our position efficiently;
- changes in governmental regulations and taxation;
- the amount and timing of actual production;
- future prices and our hedging position;
- future operating costs;
- operational risks and results; 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, 2018 would decrease from $6.2 billion to $6.0 billion.

Each of the factors impacting reserve estimation may in fact vary considerably from the assumptions used in estimating the reserves. For these reasons, estimates of natural gas reserves may vary substantially. Actual production, revenues and expenditures with respect to our 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 natural gas reserves.

Developing and producing natural gas wells is a high-risk activity.

Our growth is materially dependent upon the success of our drilling program. Drilling for natural gas and oil involves numerous risks, including the risk that an encountered well does not produce in sufficient quantities to make the well economically viable. The cost of drilling, completing and operating wells is substantial and uncertain, and drilling operations may be curtailed, delayed or canceled as a result of a variety of factors beyond our control, including those discussed in "*Our operations are subject to operating risks that could increase our operating expenses and decrease our production levels which could adversely affect our results of operations. Our operations are also subject to hazards, and any losses or liabilities, we suffer from such hazards may not be fully covered by our insurance policies*" set forth below.

Our future drilling activities may not be successful, and if they are unsuccessful, such failure will have an adverse effect on our future results of operations and financial condition. Our overall drilling success rate or our drilling success rate within a particular geographic area may decline. We may be unable to drill identified or budgeted wells within our expected time frame, or at all. We may be unable to drill a particular well because, in some cases, we identify a drilling location before we have leased all of the interests required to drill the well in that location. Similarly, our drilling schedule may vary from our capital budget. The final determination with respect to the drilling of any scheduled or budgeted wells will be dependent on a number of factors, including:

- the results of delineation efforts and the acquisition, review and analysis of seismic data;
- the availability of sufficient capital resources to us and any other participants in a well for the drilling of the well;
- whether we are able to acquire on a timely basis all of the leasehold interests required for the well, including through swap transactions with other operators;
- whether we are able to obtain, on a timely basis or at all, the permits required to drill the wells;
- whether production levels align with estimates;
- economic and industry conditions at the time of drilling, including prevailing and anticipated prices for natural gas and oil and the availability of drilling rigs and crews;

- the formation as to which we drill, as the cost structure between wet gas which requires additional processing and dry gas varies; and
- our financial resources and results.

Our business strategy focuses on horizontal drilling and production in the Marcellus and Utica Shale plays in the Appalachian Basin. Drilling horizontal wells is technologically difficult and involves risks relating to our ability to fracture stimulate the planned number of stages and to successfully run casing the length of the well bore and involves a higher risk of failure when compared to vertical wells. Additionally, drilling a horizontal well involves higher costs, which results in the risks of our drilling program being spread over a smaller number of wells, and that, in order to be profitable, each horizontal well will need to produce at a higher level in order to cover the higher drilling costs. Similarly, the average lateral length of the horizontal wells we drill has generally been increasing. Longer-lateral wells are typically more expensive and require more time for preparation and permitting. In addition, we use multi-well pads instead of single-well sites. The use of multi-well pad drilling increases some operational risks because problems affecting the pad, or a single well could adversely affect production from all of the wells on the pad. Pad drilling can also make our overall production, and therefore our revenue and cash flows, more volatile, because production from multiple wells on a pad will typically commence simultaneously. While we believe that we are better served by drilling horizontal wells using multi-well pads, the risk component involved in such drilling will be increased in some respects, with the result that we might find it more difficult to achieve economic success in our drilling program.

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

Our exploration for and production of natural gas and CNXM’s gathering, compression and transportation operations involve numerous operational 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, suspend, 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 risks that may have a significant impact on our natural gas operations include those relating to, among other things, unexpected drilling conditions (pressure or irregularities in geologic formations or wells, material and equipment failures, fires, ruptures, landslides, mine subsidence, explosions or other accidents and environmental concerns and adverse weather conditions); similar operational or design issues relating to pipelines, compressor stations, pump stations, related equipment and surrounding properties, including with respect to materials and equipment developed, designed or installed or properties owned or operated by third-parties; challenges relating to transportation, pipeline infrastructure and capacity for treatment or disposal of waste water generated in drilling, completion and production operations and failure to obtain, or delays in the issuance of, permits at the state or local level and the resolution of regulatory concerns.

The realization of any of these risks could adversely affect our ability to conduct our operations, materially increase our costs, 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 properties and our natural gas production or transportation facilities;
- pollution and other environmental damage to our properties or the properties of others;
- potential legal liability and monetary losses;
- damage to our reputation within the industry or with customers;
- regulatory investigations and penalties;

- suspension of our operations; and
- repair and remediation costs.

The occurrence of any of these events in our gas operations that prevents delivery of natural gas to a customer and is not excusable as a force majeure event under our supply agreement, could result in economic penalties, suspension or ultimately termination of the supply agreement.

Although we and CNXM 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 or disruption in our 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. 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.

Our identified drilling locations are scheduled out over multiple years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

Our management team has specifically identified and scheduled certain drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. These drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including natural gas and oil prices, the availability and cost of capital, drilling and production costs, the acquisition on acceptable terms of any leasehold interests we do not control but that are necessary to complete the drilling unit, including potentially through third-party swap transactions, availability of drilling services and equipment, drilling results, lease expirations, transportation constraints, regulatory and zoning approvals and other factors. Because of these uncertain factors, we do not know if the numerous drilling locations we have identified will ever be drilled. We will require significant additional capital over a prolonged period in order to pursue the development of these locations, and we may not be able to raise or generate the capital required to do so. Any drilling activities we are able to conduct on these locations may not be successful or result in our ability to add additional proved reserves or may result in a downward revision of our estimated proved reserves, which could have a material adverse effect on our business and results of operations.

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

Our future growth prospects are dependent upon our ability to identify optimal strategies for investing our capital resources to produce superior rates of return. 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, corporate items (including share and debt repurchases) 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.

Our development and exploration projects, as well as CNXM’s midstream system development, require substantial capital expenditures and if we fail to generate sufficient cash flow or obtain required capital or financing on satisfactory terms, our natural gas reserves may decline, and financial results may suffer.

As part of our strategic determinations, we expect to continue to make substantial capital expenditures in the development and acquisition of natural gas reserves. Further, CNXM will need to make substantial capital expenditures to fund its share of growth capital expenditures associated with its Anchor Systems, as well as to fund its share of expenditures associated with its 5% controlling interests in the Additional Systems or to purchase or construct new midstream systems. If CNXM is unable to make sufficient or effective capital expenditures, it will be unable to maintain and grow its business.

CNXM's amended gathering agreement with us, CNXM's largest customer, includes minimum well commitments; however, that gas gathering agreement and the gas gathering agreements CNXM has with other third-parties impose obligations on CNXM to invest capital which is not fully protected against volumetric risks associated with lower-than-forecast volumes flowing through its gathering systems. To the extent CNXM’s customers are not contractually obligated to, and determine not to, develop their properties in the areas covered by CNXM’s acreage dedications, the resulting decreases in the development of reserves by CNXM customers could result in reduced volumes serviced by CNXM and a commensurate decline in revenues and cash flows.

There is no assurance that we or CNXM will have sufficient cash from operations, borrowing capacity under each company’s respective credit facilities or the ability to raise additional funds in the capital markets to meet our capital requirements. If cash flow generated by our operations or available borrowings under either company’s 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 and midstream activities, 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.

Regulation of greenhouse gas emissions at the federal or state level may increase our operating costs and reduce the value of our natural gas assets and such regulation, as well as uncertainty concerning such regulation, could adversely impact the market for natural gas, as well as for our securities.

The issue of global climate change continues to attract considerable public and scientific attention with underlying concern about the impacts of human activity, especially the emissions of greenhouse gases (“GHGs”) such as carbon dioxide (“CO2”) and methane, on the environment.

The EPA, under the Climate Action Plan, elected to regulate GHGs under the Clean Air Act (“CAA”) to limit emissions of CO2 from natural gas-fired power plants. 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 August 2015, the EPA finalized the Clean Power Plan Rule to cut carbon pollution from existing power plants, which became effective on December 22, 2015. While consolidated petitions challenging the Clean Power Plan Rule are ongoing at the circuit court level, a mid-litigation application to the Supreme Court has resulted in a current stay of the Clean Power Plan Rule. In April 2017, the EPA announced that it was initiating a review of the Clean Power Plan consistent with President Trump’s Executive Order 13783, and in October 2017 published a proposed rule to formally repeal the Clean Power Plan. On August 20, 2018, the EPA issued the proposed “Affordable Clean Energy Rule.” The comment period on the proposal closed on October 31, 2018, and the EPA is considering the comments submitted. On November 21, 2018, the EPA filed a status report in which the EPA indicated that it expected to take final rulemaking action on a replacement rule for the Clean Power Plan by the first part of 2019.

The EPA has adopted regulations under existing provisions of the federal Clean Air Act that establish Prevention of Significant Deterioration, or PSD, construction and Title V operating permits for large stationary sources. Facilities requiring PSD permits may also be required to meet “best available control technology” (BACT) standards. Rulemaking related to GHG could alter or delay our ability to obtain new and/or modified source permits.

The EPA has also adopted rules to control volatile organic compound emissions from certain oil and gas equipment and operations as part of its initiative to reduce methane emissions. In response to subsequent judicial involvement, the EPA issued a proposed rule in July 2017 that would stay the methane rule for two years, but this rule is not yet final and is subject to public notice, comment, and legal challenges.

Additionally, the application of the CAA to CNX and CNXM facilities, as well as the application of state sponsored permitting programs provide regulatory uncertainty and therefore present risks, including risks regarding hitting production objectives, and cost for controls and compliance. Some states in which we operate, including Pennsylvania are contemplating measures, or have issued mandates, to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and potential cap-and-trade programs. Most of these types of programs require major source of emissions or major producers of fuels to acquire and surrender emission allowances, with the number of allowances available being reduced each year until a target goal is achieved. The cost of these allowances could increase over time. While new laws and regulations that are aimed at reducing GHG emissions will increase demand for natural gas, they may also result in increased costs for permitting, equipping, monitoring and reporting GHGs associated with natural gas production and use.

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

We and CNXM are subject to various stringent federal, state and local laws and regulations relating to the discharge of materials into, and protection of, the environment. Numerous governmental authorities, such as the EPA and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, oftentimes requiring difficult and costly response actions. These laws and regulations may impose numerous obligations that are applicable to our, CNXM’s and our respective customers' operations. Failure to comply with these laws, regulations and permits may result in joint and several or strict liability or the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations, and/or the issuance of injunctions limiting or preventing some or all of our operations. Private parties, including the owners of the properties through which CNXM’s gathering systems pass, may also have the right to pursue legal actions to enforce compliance, as well as to seek damages for non-compliance, with environmental laws and regulations or for personal injury or property damage. We may not be able to recover all or any of these costs from insurance. There is no assurance that changes in or additions to public policy regarding the protection of the environment will not have a significant impact on our operations and profitability.

Our operations, and those of CNXM, also pose risks of environmental liability due to leakage, migration, releases or spills from our operations to surface or subsurface soils, surface water or groundwater. Certain environmental laws impose strict as well as joint and several liability for costs required to investigate, remediate, and restore sites where hazardous substances, hydrocarbons or solid wastes have been stored or released. We may also be subject to fines and penalties for such releases. We may be required to remediate contaminated properties currently or formerly operated by us regardless of whether such contamination resulted from the conduct of others or from consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. In addition, claims for damages to persons or property, including natural resources, may result from the environmental, health and safety impacts of our operations.

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, or to develop and implement species-specific protection and enhancement plans and schedules 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, including the Northern Long-Earned and Indiana bats. Further consideration for listing species within our operating region is expected, and CNX considers this uncertainty, as well as the cost to comply with stringent mitigation requirements, a risk to cost and operational timing.

CNX utilizes pipelines extensively for its natural gas and water businesses. Stream encroachment and crossing permits from the Army Corps of Engineers (ACOE) are often required for certain impacts these pipelines cause to streams and wetlands. In June 2017, the EPA and the Army Corps of Engineers proposed a rule that would initiate the first step in a two-step process intended to review and revise the definition of “waters of the United States” under the Clean Water Act. The EPA moved forward with the first step on December 11, 2018, when it issued a proposed, revised rule which would replace a prior 2015 rule with pre-2015 regulations, and which narrowed language defining “waters of the United States” under the Clean Water Act that existed prior to that time. This proposal is subject to public comment and the rulemaking process. The second step would be a notice-and-comment rulemaking in which federal agencies will conduct a substantive reevaluation of such definition. While we cannot at this time predict the final form that the rule will ultimately take, such rulemaking could lead to additional mitigation costs and severely limit CNX’s operations.

Other regulations applicable to the natural gas industry are under constant review for amendment or expansion at both the federal and state levels. Any future changes may increase the costs of producing natural gas and other hydrocarbons, which would adversely impact our cash flows and results of operations. For example, hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight unconventional shale formations. 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 agencies. The disposal of produced water and other wastes in underground injection disposal wells is regulated by the EPA under the federal Safe Drinking Water Act or by various states in which we conduct operations 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.

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

We rely on third-party contractors to provide key services and equipment for our operations. We contract with third-parties for well services, related equipment, and qualified experienced field personnel to drill wells, construct pipelines and conduct field operations. We also utilize third-party contractors to provide land acquisition and related services to support our land operational needs. The demand for these services, this equipment and for qualified and experienced field personnel to drill wells, construct pipelines 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. Weather may also play a role with respect to the relative availability of certain materials. Historically, there have been shortages of drilling and workover rigs, pipe, compressors and other equipment as demand for rigs and equipment has increased along with the number of wells being drilled. The costs and delivery times of equipment and supplies are substantially greater in periods of peak demand, including increased demand for plays outside of our area of geographic focus. Accordingly, we cannot assure that we will be able to obtain necessary services, 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.

Any of the above shortages may lead to escalating prices for drilling equipment, land services, 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. Additionally, a decrease in the availability of these services, equipment and personnel could lead to a decrease in our natural gas production, increase our costs of natural gas production, and decrease our anticipated profitability. 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.

We attempt to mitigate the risks involved with increased natural gas production 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 types of contracts expose us to economic risk during a downturn in demand or during periods of oversupply. For example, in the year ended December 31, 2018 and 2017, due to the oversupply of gas in our markets, we made payments under these types of contracts of approximately $7 million and $40 million, respectively, 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.

If natural gas prices decrease or drilling efforts are unsuccessful, we may be required to record write-downs of our proved natural gas properties. Additionally, changes in assumptions impacting management’s estimates of future financial results as well as other assumptions related to the Company's stock price, weighted-average cost of capital, terminal growth rates and industry multiples, could cause goodwill and other intangible assets we hold to become impaired and result in material non-cash charges to earnings.

Lower natural gas prices or wells that produce less than expected quantities of natural gas 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 certain of 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.

As a result of our acquisition of the 50% interest in CNX Gathering in the first quarter of 2018, we acquired approximately $925 million of goodwill and other intangible assets. Future acquisitions may also lead to the acquisition of additional goodwill or other intangible assets. At least annually, or whenever events or changes in circumstances indicate a potential impairment in the carrying value as defined by GAAP, we will evaluate this goodwill and other intangible assets for impairment by first assessing qualitative factors to determine whether the existence of events or circumstances leads to a determination that it is more likely than not that the fair value of the reporting unit is less than the carrying amount. Estimated fair values could change if, for example, there are changes in the business climate, unanticipated changes in the competitive environment, adverse legal or regulatory actions or developments, changes in capital structure, cost of debt, interest rates, capital expenditure levels, operating cash flows, or market capitalization. The future impairment of these assets could require material non-cash charges to our results of operations, which could have a material adverse effect on our reported earnings and results of operations for the affected periods. In May 2018, CNX determined that the carrying value of a portion of the customer relationship intangible assets that were acquired in connection with the Midstream Acquisition exceeded their fair value in conjunction with the Asset Exchange Agreement with HG Energy II Appalachia, LLC (See Note 6 - Acquisitions and Dispositions in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for further discussion). CNX recognized an impairment on this intangible asset of $19 million, which is included in Impairment of Other Intangible Assets in the Consolidated Statements of Income.

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

The natural gas, exploration, production and midstream industries are intensely competitive with companies from various regions of the United States and, increasingly, competition in the international markets. The industry has been experiencing increased competitive pressures as a result of both consolidation within the exploration and production space, along with the emergence of stand-alone midstream companies. Many of the companies with which we and CNXM compete 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. There is also increased competition within the industry as a result of oil-focused drilling, where natural gas is produced as an ancillary byproduct and may be sold at prices below market. The highly competitive environment in which we operate may negatively impact our ability to acquire additional properties at prices or upon terms we view as favorable. The competitive environment can also make it more challenging to discover new natural gas resources, evaluate and select suitable properties and to consummate these transactions on acceptable terms. Any reduction in our ability to compete in current or future natural gas markets could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Additionally, CNXM's ability to increase throughput on its midstream systems and any related revenue from third-parties is subject to capacity availability on its existing systems, its ability to expand its existing systems, contractual obligations to its existing customers and competition from third parties, primarily operators of other natural gas gathering systems. The fact that a substantial majority of the capacity of CNXM's midstream systems will be necessary to service the production of CNX and one third-party customer and we and that third-party will receive priority of service for the provision of CNXM midstream services over other third-parties, may result in CNXM not having the capacity to provide services to other third-party customers. In addition, potential third-party customers who are significant producers of natural gas and condensate may develop their own midstream systems in lieu of using CNXM's systems. All of these competitive pressures could have a material adverse effect on CNXM's business, results of operations, financial condition, cash flows and ability to make cash distributions and therefore, could have a material adverse effect on our investment in CNXM.

Deterioration in the economic conditions in any of the industries in which our customers operate, a domestic or worldwide financial downturn, or negative credit market conditions may have a material adverse effect on our liquidity, results of operations, business and financial condition that we cannot predict.

Economic conditions in a number of industries in which our customers operate, such as electric power generation, have experienced substantial deterioration in the past, resulting in reduced demand for natural gas. 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 that 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 business;
- the tightening of credit or lack of credit availability to our customers could adversely affect us, as our ability to receive payment for natural gas sold and delivered depends on the continued creditworthiness of our customers;
- 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 reserves; and
- a decline in our creditworthiness 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.

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 18, 2019, we expect these transactions will represent approximately 376.0 Bcf of our estimated 2019 production at an average price of $2.71 per Mcf, 468.6 Bcf of our estimated 2020 production at an average price of $2.55 per Mcf, 410.3 Bcf of our estimated 2021 production at an average price of $2.44 per Mcf, 276.6 Bcf of our estimated 2022 production at an average price of $2.48 per Mcf, and 127.0 Bcf of our estimated 2023 production at an average price of $2.35 per Mcf. 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 hedging arrangements in the future, reduce our future use of hedging arrangements or are unable to engage in hedging arrangements due to lack of acceptable counterparties, 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. Increases or decreases in forward market prices could result in material unrealized (non-cash) losses or gains on commodity derivative instruments resulting in volatility in reported earnings.

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;
- we are unable to find available counterparties in the future with which to enter into hedges and counterparties able to enter into basis hedge contracts;
- the creditworthiness of our counterparties or their guarantors is substantially impaired; and
- counterparties have credit limits that may constrain our ability to hedge additional volumes.

Existing and future governmental laws, regulations and other legal requirements and judicial decisions that govern our business may increase our costs of doing business and may restrict our operations.

There are numerous governmental regulations applicable to the natural gas industry that are not directly related to environmental regulation, many of which are under constant review for amendment or expansion at the federal and state level. Any future modifications in such regulations, changes promulgated by the courts, or interruptions experienced in the operation of our governing bodies, may affect, among other things, our ability to develop the resource, obtain permits, as well as, potential impacts to the pricing or marketing of natural gas production.

For example, currently CNXM's gathering operations are exempt from regulation by the Federal Energy Regulatory Commission (FERC) under the Natural Gas Act (NGA). Although FERC has not made any formal determinations with respect to any of CNXM's facilities considered to be gathering facilities, CNXM believes that the natural gas pipelines in its gathering systems meet the traditional tests FERC has used to establish that a natural gas pipeline is a gathering pipeline not subject to FERC jurisdiction. However, this issue has been the subject of substantial litigation, and if FERC were to consider the status of an individual facility and determine that the facility or services provided by it are not exempt from FERC regulation under the NGA, the rates for, and terms and conditions of, services provided by such facility would become subject to regulation by FERC. Such regulation could decrease revenue, increase operating costs, and, depending upon the facility in question, could adversely affect results of operations and cash flows for CNXM.

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 Public Utility Commission (PUC) oversight of Class I gathering lines, and required standards and fees for 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 midstream activities of CNXM and other third-party providers with whom we interact, requiring changes in reporting, as well as increased costs.

Various judicial decisions that may directly or indirectly impact natural gas drilling could also serve to increase our cost of doing business or restrict our operations. For example, a recent Pennsylvania case currently on appeal involves concepts of landowner rights, trespass claims and the historic common law concept of "rule of capture." Although the case has not yet been resolved, the ultimate judicial outcome could negatively impact future shale drilling and hydraulic fracturing within the Commonwealth of Pennsylvania if the court finds that fracking could be considered trespassing in certain circumstances.

We may incur significant costs and liabilities as a result of pipeline operations and related increase in the regulation of gas gathering pipelines.

Pipeline and Hazardous Materials Safety Administration (PHMSA) has adopted regulations requiring pipeline operators to develop integrity management programs for transportation pipelines and related facilities located where a leak or rupture could do the most harm, i.e., in "high consequence areas." The regulations require operators to:

- perform ongoing assessments of pipeline and related facility integrity;
- identify and characterize applicable threats to pipeline segments that could impact a high consequence area;
- improve data collection, integration and analysis;
- repair and remediate the pipeline as necessary; and
- implement preventive and mitigating actions.

Should our or CNXM's operations fail to comply with PHMSA or comparable state regulations, we could be subject to substantial penalties and fines, including civil penalties of up to $209,000 per violation, with a maximum of $2,909,022 for those related series of violations. In January 2017, PHMSA released a pre-publication copy of its final hazardous liquid pipeline safety regulations that would significantly extend the integrity management requirements to previously exempt pipelines and would impose additional obligations on hazardous liquid pipeline operators that are already subject to the integrity management requirements. However, due to the change in Presidential administrations, PHMSA's final hazardous liquid pipeline safety rule has not yet taken effect, though PHMSA is expected to finalize its hazardous liquid pipeline safety in the near term. PHMSA's proposed rule would also require annual reporting of safety-related conditions and incident reports for all hazardous liquid gathering lines and gravity lines, including pipelines exempt from PHMSA regulations.

PHMSA also issued a separate regulatory proposal in July 2015 that would impose pipeline incident prevention and response measures on natural gas and hazardous liquid pipeline operators and in April 2016, published a Notice of Proposed Rule making that would significantly modify existing regulations related to reporting, impact, design, construction, maintenance, operations and integrity management of gas transmission and gathering pipelines. As proposed, compliance with the rule could have a material adverse effect on our or CNXM's operations. However, the ultimate impact of the rule on our and CNXM remains uncertain until the rulemaking is finalized. The adoption of these regulations, which apply more comprehensive or stringent safety standards than we are currently subject to, could require us to install new or modified safety controls, pursue new capital projects, or conduct maintenance programs on an accelerated basis, all of which could require us to incur increased operational costs that could be significant. While we cannot predict the outcome of legislative or regulatory initiatives, such legislative and regulatory changes could have a material effect on our cash flow.

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, transport or recycle the water 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 we are unable to dispose of or recycle the water at a reasonable cost and within applicable environmental rules, our ability to produce natural gas economically and in sufficient quantities could be impaired.

As part of our drilling and production in shale formations, we use hydraulic fracturing processes. These processes require access to adequate sources of water, which may not be available in proximity to our operations or at certain times of the year. To ensure that we have adequate water available for our operations, we may be required to invest substantial amounts of capital in water pipelines which are used for relatively short periods of time. Increased regulation of these water pipelines could cause us to invest additional capital, alter our disposal or transportation method or affect our operations in other manners. Alternatively, we may be required to truck water, and we may not be able to contract for sufficient water hauling trucks to meet our needs.

Further, we must remove the portion of the water 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. This water can be either disposed of or recycled for use in other hydraulic fracturing operations. In the event we are forced to dispose of water rather than recycle it, our costs may increase. 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 obtain 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 in an economically efficient manner, could increase our costs and delay our operations, which will adversely impact our cash flow and results of operations.

Failure to find or acquire economically recoverable natural gas reserves to replace our current natural gas reserves will cause our levels of natural gas reserves and production to 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, 2018, 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, exploiting and selling our current reserves and economically finding or acquiring additional economically recoverable reserves. We may not be able to develop, find or acquire additional economically recoverable reserves to replace our current and future production at acceptable costs.

In addition, the level of natural gas and condensate volumes handled through the CNXM midstream systems depends on the level of production from natural gas wells dedicated to such midstream systems, which may be less than expected and which will naturally decline over time. In order to maintain or increase throughput levels on CNXM's midstream systems, CNXM must obtain production from new wells completed by us and any third-party customers on acreage dedicated to the CNXM midstream systems or execute agreements with other third-parties in CNXM's areas of operation. CNXM has no control over producers' levels of development and completion activity in its areas of operations, the amount of reserves associated with wells connected to CNXM's systems or the rate at which production from a well declines.

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

As of December 31, 2018, CNX's total long-term indebtedness, excluding CNXM, was approximately $1.9 billion of which approximately (i) $1.3 billion was under our 5.875% senior unsecured notes due 2022 plus $2.1 million of unamortized bond premium, (ii) $612.0 million was under our senior secured credit facility and (iii) $13.3 million of capitalized leases due through 2021. 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 natural gas reserves or other general corporate requirements;
- limiting our flexibility in planning for, or reacting to, changes in our business and in the natural gas industry;

- 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.

Further, LIBOR and certain other interest rate “benchmarks” are the subject of recent national, international, and other regulatory guidance and proposals for reform. These reforms may cause such benchmarks to perform differently than in the past or have other consequences which cannot be predicted. On July 27, 2017, the United Kingdom’s Financial Conduct Authority, which regulates LIBOR, publicly announced that it intends to stop persuading or compelling banks to submit LIBOR rates after 2021. It is expected that a transition away from the widespread use of LIBOR to alternative rates will occur over the course of the next several years. As a result of this transition, LIBOR may disappear entirely or perform differently than in the past, and interest rates on our variable rate indebtedness and other financial instruments tied to LIBOR rates, as well as the revenue and expenses associated with those financial instruments, may be adversely affected.

Our senior secured credit facility and the indentures governing our 5.875% 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% 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 maximum net leverage ratio and a minimum current ratio, as defined therein. Our senior secured credit agreement and the indentures governing our 5.875% 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. Further, CNXM’s existing $600 million revolving credit facility and CNXM’s $400 million of 6.50% senior notes, neither of which are guaranteed by CNX, subjects CNXM to certain financial and/or other restrictive covenants and other restrictions similar to those in our senior secured credit agreement and indentures.

If our or CNXM’s cash flows and capital resources are insufficient to fund our respective debt service obligations, including repayment of such obligations at maturity, we or CNXM, as the case may be, 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 respective 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% senior unsecured notes restrict our ability to sell assets and the use of 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.

Our lenders use the loan value of our proved natural gas reserves to determine the borrowing base under our $2.1 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, asset sales and lending requirements or regulations. Significant reductions in our borrowing base below $2.1 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 $2.1 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 $2.1 billion. Our borrowing base is redetermined by the lenders twice per year, and the next scheduled borrowing base redetermination is expected to occur in the Spring of 2019. 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 also decrease our borrowing base. Please read: “Risk Factors - *We face uncertainties in estimating our economically recoverable natural gas 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 $2.1 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 operations. We also could be required to repay any outstanding 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 those proceeds may not be adequate to meet any debt service obligations then due.

Changes in federal or state income tax laws could cause our financial position and profitability to deteriorate.

The passage of legislation or any other changes in U.S. federal income tax law could eliminate or postpone certain tax deductions that are currently available with respect to natural gas exploration and development. Any such change could negatively affect our financial condition and results of operations. For instance, recent tax law changes effective as of the beginning of 2018 will limit the ability of corporations to take certain interest deductions and have eliminated a corporation's ability to take deductions for income attributable to domestic production activities.

Additionally, legislation has been proposed from time to time in the states in which we operate - primarily Pennsylvania, Ohio and West Virginia - that would impose additional taxes or increase taxes on the production from our wells. The proposed tax rates have varied but would represent a greater financial burden on the economics of the wells we drill in these states.

Cyber-incidents could have a material adverse effect on our business, financial condition or results of operations.

Cyber-incidents, including cyber-attacks, may significantly affect us or the operations of our customers and business partners, as well as impact general economic conditions, consumer confidence and spending and market liquidity. Strategic targets, including energy-related assets, may be at greater risk of future incidents than other targets in the United States. A cyber incident could result in information theft, data corruption, operational disruption including environmental and safety issues resulting from a loss of control of field equipment and assets, and/or financial loss. 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.

The oil and natural gas industry has become increasingly dependent upon digital technologies, including information systems, infrastructure and cloud applications and services, to operate our businesses, 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, monitor and control our field equipment and assets, and perform other activities related to our businesses. Our business partners, including vendors, service providers, and financial institutions, are also dependent on digital technology.

As dependence on digital technologies has increased, cyber incidents, including deliberate attacks or unintentional events, have also increased. A cyber-incident could include gaining unauthorized access to digital systems for purposes of misappropriating assets or sensitive information, corrupting data, or causing operational disruption, or result in denial-of-service on websites. SCADA (supervisory control and data acquisition) based systems are potentially vulnerable to targeted cyber-attacks due to their critical role in operations.

Our technologies, systems, networks, data centers and those of our business partners may become the target of cyber-incidents or information security breaches that could result in the unauthorized release, gathering, monitoring, misuse, loss or destruction of proprietary and other information, or other disruption of our business operations. In addition, certain cyber incidents, such as surveillance, may remain undetected for an extended period.

Deliberate attacks on our assets, or security breaches in our systems or infrastructure, 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, damage to our reputation, other operational disruptions and third-party liability, including the following:

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- a cyber-incident impacting one of our vendors or service providers could result in supply chain disruptions, loss or corruption of our information or other negative consequences, any of which could delay or halt development of additional infrastructure, effectively delaying the start of cash flows from the project;
- a cyber-incident related to our facilities may result in equipment damage or failure;
- a cyber-incident impacting midstream or downstream pipelines could prevent our product from being delivered, resulting in a loss of revenues;
- a cyber-incident impacting a communications network or power grid could cause operational disruption resulting in loss of revenues;
- a deliberate corruption of our financial or operational data could result in events of non-compliance which could lead to regulatory fines or penalties; and
- business interruptions could result in expensive remediation efforts, distraction of management, damage to our reputation, or a negative impact on the price of our units.

Our implementation of various internal and externally-facing controls and processes, including appropriate internal risk assessment and internal policy implementation, globally incorporating a risk-based cyber security framework to monitor and mitigate security threats and other strategies to increase security for our information, facilities and infrastructure is costly and labor intensive. Moreover, there can be no assurance that such measures will be sufficient to prevent security breaches or other cyber-incidents from occurring. As cyber threats continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any information security vulnerabilities.

Construction of new gathering, compression, dehydration, treating or other midstream assets by CNXM may not result in revenue increases and may be subject to regulatory, environmental, political, legal and economic risks, which could adversely affect CNXM‘s cash flows, results of operations and our financial condition.

The construction of additions or modifications to CNXM’s existing systems involves numerous regulatory, environmental, political and legal uncertainties beyond its control and may require the expenditure of significant amounts of capital. Financing may not be available on economically acceptable terms or at all. If these projects are undertaken, they may not be completed on schedule, at the budgeted cost or at all.

Revenues may not increase immediately (or at all) upon the expenditure of funds on a particular project. For instance, if a processing facility is built, the construction may occur over an extended period of time, and CNXM may not receive any material increases in revenues until the project is completed. Additionally, facilities may be constructed to capture anticipated future production growth in an area in which such growth does not materialize. As a result, new gathering, compression, dehydration, treating or other midstream assets may not be able to attract enough throughput to achieve the expected investment return, which could adversely affect CNXM’s business, financial condition, results of operations, cash flows and ability to make cash distributions.

The construction of additions to CNXM’s existing assets may require it to obtain new rights-of-way prior to constructing new pipelines or facilities, which may not be obtained in a timely fashion or in a way that allows CNXM to connect new natural gas supplies to existing gathering pipelines or capitalize on other attractive expansion opportunities. Additionally, it may become more expensive to obtain new rights-of-way or to expand or renew existing rights-of-way. If the cost of renewing or obtaining new rights-of-way increases, cash flows could be adversely affected.

Our success depends on key members of our management and our ability to attract and retain experienced technical and other professional personnel.

Our future success depends to a large extent on the services of our key employees. The loss of one or more of these individuals could have a material adverse effect on our business. Furthermore, competition for experienced technical and other professional personnel remains strong. If we cannot retain our current personnel or attract additional experienced personnel, our ability to compete could be adversely affected. Also, the loss of experienced personnel could lead to a loss of technical expertise.

Terrorist activities could materially and adversely affect our business and results of operations.

Terrorist attacks, including eco-terrorism, and the threat of terrorist attacks, whether domestic or foreign, as well as military or other actions taken in response to these acts, could affect the energy industry, the environment and industry related economic conditions, including our operations and the operations of our customers, as well as general economic conditions, consumer confidence and spending and market liquidity. Strategic targets, including energy-related assets, may be at greater risk of future attacks than other targets in the United States. The occurrence or threat of terrorist attacks in the United States or other countries could adversely affect the global economy in unpredictable ways, including the disruption of energy supplies and markets, increased volatility in commodity prices or the possibility that the infrastructure on which we rely could be a direct target or an indirect casualty of an act of terrorism, and, in turn, could materially and adversely affect our business and results of operations. Our insurance may not protect us against such occurrences.

We may operate a portion of our business with one or more joint venture partners or in circumstances where we are not the operator, which may restrict our operational and corporate flexibility; actions taken by the other partner or third-party operator 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 natural gas industry, we may operate one or more of our properties with a joint venture partner, or contract with a third-party to control operations. These relationships could require us to share operational and other control, 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 such circumstances, our rights to participate may be adversely affected. If a joint venture partner is unable or fails to pay its portion of development costs or if a third-party operator does not operate in accordance with our expectations, our costs of operations could be increased. We could also incur liability as a result of actions taken by a joint venture partner or third-party operator. Disputes between us and the other party may result in litigation or arbitration that would increase our expenses, delay or terminate projects and distract our officers and directors from focusing their time and effort on our business.

We do not completely 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 completely control the timing of divestitures, and delays in completing divestitures may reduce the benefits we may receive from them, such as elimination of management distraction by selling non-core assets and the receipt of cash proceeds that contribute to our liquidity. 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 assets or 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 and to identify and appropriately manage any liabilities assumed as part of the acquisition. The process of integrating acquired businesses or assets 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 or assets into our existing operations could have a material adverse effect on our financial condition and results of operations.

CNX 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 pending purported class action lawsuits dealing with claimants' alleged entitlements to, and accounting for, natural gas royalties. There is also the possibility that we may become involved in future suits, including, for example, those being brought by communities against fossil fuel producers relating to climate change, which are beginning to gain prevalence in the courts. 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 18- 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.

There is no guarantee that we will continue to repurchase shares of our common stock under our current or any future share repurchase program at levels undertaken previously or at all. Any determinations to repurchase shares of our common stock will be at the discretion of our board of directors based upon a review of all relevant considerations.

We previously announced a one-year $200 million share repurchase program that was authorized by our board of directors in September 2017, amended to increase the program to $450 million on October 30, 2017 and extended on July 30, 2018 to December 31, 2018. On October 26, 2018, our board of directors approved an additional $300 million share repurchase authorization, which is not subject to an expiration date. The repurchase program does not require us to acquire any specific number of shares. Our board of director's determination to repurchase shares of our common stock will depend upon market conditions, applicable legal requirements, contractual obligations and other factors that the board of directors deems relevant. Based on an evaluation of these factors, our board of directors may determine not to repurchase shares or to repurchase shares at reduced levels from those anticipated by our shareholders.

Negative public perception regarding our industry could have an adverse effect on our operations.

Negative public perception regarding our industry resulting from, among other things, operational incidents or concerns raised by advocacy groups about hydraulic fracturing, emissions and pipeline projects, could result in increased regulatory scrutiny, which could then result in additional laws, regulations, guidelines and enforcement interpretations, at the federal or state level. These actions may cause operational delays or restrictions, increased operating costs, additional regulatory burdens and increased risk of litigation. Moreover, governmental authorities exercise considerable discretion in the timing and scope of permit issuance and the public may engage in the permitting process, including through intervention in the courts. Negative public perception could cause the permits we need to conduct our operations to be withheld, delayed, or burdened by requirements that restrict our ability to profitably conduct our business.

In connection with the separation, CONSOL Energy has agreed to indemnify us for certain liabilities and we have agreed to indemnify CONSOL Energy for certain liabilities. If we are required to pay under these indemnities to CONSOL Energy, our financial results could be negatively impacted. The CONSOL Energy indemnity may not be sufficient to hold us harmless from the full amount of liabilities for which CONSOL Energy has been allocated responsibility, and CONSOL Energy may not be able to satisfy its indemnification obligations in the future.

Pursuant to the Separation and Distribution Agreement and certain other agreements with CONSOL Energy, CONSOL Energy has agreed to indemnify us for certain liabilities, and we have agreed to indemnify CONSOL Energy for certain liabilities, in each case for uncapped amounts. More specifically, CONSOL Energy assumed all liabilities related to their current and our former coal business, including liabilities having a book value of $955 million and liabilities that may arise due to the failure of purchasers of coal assets that we had previously disposed. Additionally, we remain liable as a guarantor on certain liabilities that were assumed by CONSOL Energy in connection with the separation. The estimated value of these guarantees was approximately $192 million at the time of the separation. Although CONSOL Energy agreed to indemnify us to the extent that we are called upon to pay any of these liabilities, there is no assurance that CONSOL Energy will satisfy its obligations to indemnify us in these situations. For example, we could be liable for liabilities assumed by Murray Energy and its subsidiaries (Murray Energy) in connection with the disposition of certain mines to Murray Energy in 2013 in the event that both Murray Energy and CONSOL Energy are unable to satisfy those liabilities.

Indemnities that we may be required to provide CONSOL Energy are not subject to any cap, may be significant and could negatively impact our business. Third-parties could also seek to hold us responsible for any of the liabilities that CONSOL Energy has agreed to retain. Any amounts we are required to pay pursuant to these indemnification obligations and other liabilities could require us to divert cash that would otherwise have been used in furtherance of our operating business. Further, the indemnity from CONSOL Energy may not be sufficient to protect us against the full amount of such liabilities, and CONSOL Energy may not be able to fully satisfy its indemnification obligations. Moreover, even if we ultimately succeed in recovering from CONSOL Energy any amounts for which we are held liable, we may be temporarily required to bear such losses. Each of these risks could negatively affect our business, results of operations and financial condition.

The separation of CONSOL Energy could result in substantial tax liability.

Under current U.S. federal income tax law, even if the distribution, together with certain related transactions, otherwise qualifies for tax-free treatment under Sections 355 and 368(a)(1)(D) of the Internal Revenue Code, the distribution may nevertheless be rendered taxable to us and our shareholders as a result of certain post-distribution transactions, including certain acquisitions of shares or assets of CNX or CONSOL Energy. The possibility of rendering the distribution taxable as a result of such transactions may limit our ability to pursue certain equity issuances, strategic transactions or other transactions that would otherwise maximize the value of our business. Under the Tax Matters Agreement that we entered into with CONSOL Energy, CONSOL Energy may be required to indemnify us against any additional taxes and related amounts resulting from (i) an acquisition of all or a portion of the equity securities or assets of CONSOL Energy, whether by merger or otherwise (and regardless of whether CONSOL Energy participated in or otherwise facilitated the acquisition), (ii) issuing equity securities beyond certain thresholds, (iii) repurchasing shares of CONSOL Energy stock other than in certain open-market transactions, (iv) ceasing to actively conduct certain of its businesses, (v) other actions or failures to act by CONSOL Energy or (vi) any of CONSOL Energy's representations, covenants or undertakings contained in any of the separation-related agreements and documents or in any documents relating to the IRS private letter ruling and/or the opinions of tax advisors being incorrect or violated. However, the indemnity from CONSOL Energy may not be sufficient to protect us against the full amount of such additional taxes or related liabilities, and CONSOL Energy may not be able to fully satisfy its indemnification obligations. Moreover, even if we ultimately succeed in recovering from CONSOL Energy any amounts for which we are held liable, we may be temporarily required to bear such losses. Each of these risks could negatively affect CNX’s business, results of operations and financial condition.

ITEM 1B. Unresolved Staff Comments

None.

ITEM 2. Properties

See Detail Operations in Item 1 of this 10-K for a description of CNX's properties.

ITEM 3. Legal Proceedings

Note 22–Commitments and Contingent Liabilities in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K is incorporated herein by reference.

ITEM 4. Mine Safety and Health Administration Safety Data

Not applicable.

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.

As of December 31, 2018, there were 116 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 CNX to the cumulative shareholder return for the same period of a peer group and the Standard & Poor's 500 Stock Index. The current peer group is comprised of CNX, Antero Resources Corporation, Cabot Oil & Gas Corporation, Chesapeake Energy Corporation, Energen Corporation, EQT Corporation, Gulfport Energy Corporation, PDC Energy, Inc., Range Resources Corporation, SM Energy Company, Southwestern Energy Co., Whiting Petroleum Corporation, and WPX Energy, Inc. The graph assumes that the value of the investment in CNX common stock and each index was $100 at December 31, 2013. The graph also assumes that all dividends were reinvested and that the investments were held through December 31, 2018.

	2013	**2014**	**2015**	**2016**	**2017**	**2018**
CNX Resources Corporation	100.0	107.4	25.7	59.3	55.0	42.9
Peer Group	100.0	88.3	38.8	53.1	42.3	27.6
S&P 500 Stock Index	100.0	144.4	143.4	157.0	187.4	175.8

Cumulative Total Shareholder Return Among CNX Resources Corporation, 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 CNX is subject to the discretion of CNX's Board of Directors, and no assurance can be given that CNX will pay dividends in the future. CNX suspended its quarterly dividend in March 2016 to further reflect the Company's increased emphasis on growth. CNX’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, CNX’s financial results, contractual and legal restrictions regarding the payment of dividends by CNX, planned investments by CNX and such other factors as the Board of Directors deems relevant. The Company's credit facility limits CNX'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 a cumulative credit calculation set forth in the facility. The total leverage ratio was 2.26 to 1.00 at December 31, 2018. The credit facility does not permit dividend payments in the event of default. The indentures to the 2022 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, 2018.

Unregistered Sales of Equity Securities and Use of Proceeds

The following table sets forth repurchases of our common stock during the three months ended December 31, 2018:

ISSUER PURCHASES OF EQUITY SECURITIES

Period	(a) Total Number of Shares Purchased (1)	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs (2)	(d) Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs (000's omitted)
October 1, 2018-October 31, 2018	3,552,158	$ 14.06	3,552,158	$300,643
November 1, 2018-November 30, 2018	712,300	$ 14.10	712,300	$290,597
December 1, 2018-December 31, 2018	2,230,834	$ 12.06	2,230,834	$263,684
Total	6,495,292		6,495,292	$854,924,000

(1) Includes shares withheld from employees to satisfy minimum tax withholding obligations associated with the vesting of restricted stock during the period.

(2) Shares repurchased as part of the Company’s previously announced one-year $450 million share repurchase program authorized by the Board of Directors in September 2017, as amended on October 30, 2017, extended on July 30, 2018, and expired on December 31, 2018. On October 26, 2018, the Company's Board of Directors approved an additional $300 million share repurchase authorization, which is not subject to an expiration date.

See Part III, Item 12. “Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters” for information relating to CNX'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, 2018, 2017, 2016, 2015 and 2014 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, 2018 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,**				
	2018	**2017**	**2016**	**2015**	**2014**
Revenue and Other Operating Income from Continuing Operations	$1,730,434	$1,455,131	$759,968	$1,198,737	$1,080,351
Income (Loss) from Continuing Operations	$883,111	$295,039	$(550,945)	$(650,198)	$(269,625)
Net Income (Loss) Attributable to CNX Resources Shareholders	$796,533	$380,747	$(848,102)	$(374,885)	$163,090
Earnings per share:					
Basic:					
Income (Loss) from Continuing Operations	$3.75	$1.29	$(2.40)	$(2.84)	$(1.17)
Income (Loss) from Discontinued Operations	—	0.37	(1.30)	1.20	1.88
Net Income (Loss)	$3.75	$1.66	$(3.70)	$(1.64)	$0.71
Diluted:					
Income (Loss) from Continuing Operations	$3.71	$1.28	$(2.40)	$(2.84)	$(1.17)
Income (Loss) from Discontinued Operations	—	0.37	(1.30)	1.20	1.87
Net Income (Loss)	$3.71	$1.65	$(3.70)	$(1.64)	$0.70
Assets from Continuing Operations	$8,592,170	$6,931,913	$6,682,770	$7,302,119	$7,968,069
Assets from Discontinued Operations	—	—	2,496,921	3,627,783	3,686,576
Total Assets	$8,592,170	$6,931,913	$9,179,691	$10,929,902	$11,654,645
Long-Term Debt from Continuing Operations (including current portion)	$2,398,501	$2,214,484	$2,456,354	$2,460,633	$3,129,433
Long-Term Debt from Discontinued Operations (including current portion)	—	—	317,715	294,222	120,128
Total Long-Term Debt (including current portion)	$2,398,501	$2,214,484	$2,774,069	$2,754,855	$3,249,561
Cash Dividends Declared Per Share of Common Stock	$—	$—	$0.010	$0.145	$0.250

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 income for all periods and other matters that affect the comparability of the selected financial data as well as uncertainties that might affect the Company’s future financial condition.

OTHER OPERATING DATA
(unaudited)

	Years Ended December 31,				
	2018	**2017**	**2016**	**2015**	**2014**
Gas:					
Net sales volumes produced (in Bcfe)	507.1	407.2	394.4	328.7	235.7

Average sales price ($ per Mcfe) (A)	$2.97	$2.66	$2.63	$2.81	$4.37
Average cost ($ per Mcfe)	$1.98	$2.23	$2.32	$2.62	$3.13
Proved reserves (in Bcfe) (B)	7,881	7,582	6,252	5,643	6,828

(A) Represents average net sales price including the effect of derivative transactions.
(B) Represents proved developed and undeveloped gas reserves at period end.

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

General

2018 Highlights

- Record total gas production of 507.1 Bcfe in 2018, 24.5% higher than 2017
  Included in CNX's 2018 production is approximately 27 Bcfe of production related to assets that were sold in 2018.
- Record Marcellus Shale production of 288.2 Bcfe in 2018, 20.4% higher than 2017.
- Increased proved reserves to 7.9 Tcfe, 4% higher than 2017.
  Increase even after a reduction of approximately 825 Bcfe of reserves related to assets that were sold in 2018.
- On January 3, 2018, the Company acquired the remaining 50% membership interest in CONE Gathering LLC (which has since been renamed CNX Gathering LLC), which holds the general partner interest and incentive distribution rights in CNXM, the entity that constructs and operates the gathering system for most of our Marcellus shale production.
- CNX sold substantially all of its shallow oil and gas assets and certain Coalbed Methane (CBM) assets in Pennsylvania and West Virginia during the second quarter of 2018.
- During the third quarter of 2018, CNX closed on the sale of substantially all of its Ohio Utica Joint Venture Assets in the wet gas Utica Shale areas of Belmont, Guernsey, Harrison, and Noble Counties, which included approximately 26,000 net undeveloped acres.
- Gas production costs continue to decline - for the year ended December 31, 2018, total gas production costs were $1.98 per Mcfe, which includes $0.90 per Mcfe of depreciation, depletion and amortization, a 11.2% decline from the prior year.
- Repurchased $384 million of common stock on the open market.
- Repurchased $411 million of 5.875% notes due in 2022.
- Called the remaining $500 million balance of 8% senior notes due April 2023.

2019 Outlook:

- Our 2019 annual gas production is expected to be at a minimum base of approximately 495-515 Bcfe.
- Our 2019 E&P capital investment is expected to be approximately $1,000-$1,080 million.

Results of Operations: ***Year Ended December 31, 2018 Compared with the Year Ended December 31, 2017***

Net Income Attributable to CNX Resources Shareholders

CNX reported net income attributable to CNX Resources shareholders of $797 million, or earnings per diluted share of $3.71, for the year ended December 31, 2018, compared to net income of $381 million, or earnings per diluted share of $1.65, for the year ended December 31, 2017.

	For the Years Ended December 31,		
(Dollars in thousands)	2018	2017	Variance
Income from Continuing Operations	$883,111	$295,039	$588,072
Income from Discontinued Operations, Net	—	85,708	(85,708)
Net Income	$883,111	$380,747	$502,364
Less: Net Income Attributable to Noncontrolling Interest	86,578	—	86,578
Net Income Attributable to CNX Resources Shareholders	$796,533	$380,747	$415,786

CNX consists of two principal business divisions: Exploration and Production (E&P) and Midstream.

The principal activity of the E&P Division is to produce pipeline quality natural gas for sale primarily to gas wholesalers. The E&P division's reportable segments are Marcellus Shale, Utica Shale, CBM, and Other Gas.

CNX's E&P Division had earnings from continuing operations before income tax of $245 million for the year ended December 31, 2018, compared to a loss from continuing operations before income tax of $63 million for the year ended December 31, 2017. Included in 2018 earnings was an unrealized gain on commodity derivative instruments of $40 million. Included in the 2017 loss was an unrealized gain on commodity derivative instruments of $248 million and $138 million of expense relating to the impairment in carrying value of Knox Energy LLC and Coalfield Pipeline Company (collectively, "Knox Energy"). See Note 6 - Acquisitions and Dispositions in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.

CNX's Midstream Division's principal activity is the ownership, operation, development and acquisition of natural gas gathering and other midstream energy assets, through CNX Gathering and CNXM, which provide natural gas gathering services for the Company's produced gas, as well as for other independent third-parties in the Marcellus Shale and Utica Shale in Pennsylvania and West Virginia. Excluded from the Midstream Division are the gathering assets and operations of CNX that have not been contributed to CNX Gathering and CNXM.

CNX's Midstream Division, which is the result of CNX's acquisition of NBL Midstream, LLC's interest in CNX Gathering LLC (See Note 6 - Acquisitions and Dispositions in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information) on January 3, 2018 (the Midstream Acquisition), had earnings from continuing operations before income tax of $134 million for the period from January 3, 2018 through December 31, 2018. As a result of the Midstream Acquisition, CNX owns and controls 100% of CNX Gathering, making CNXM a single-sponsor master limited partnership. Prior to the acquisition, CNX accounted for its interests in CNX Gathering and CNXM as an equity-method investment and as such a period to period analysis is not meaningful. The resulting gain on remeasurement to fair value of the previously held equity interest in CNX Gathering and CNXM of $624 million has been included in Gain on Previously Held Equity Interest in the Consolidated Statements of Income and is part of CNX's unallocated expenses.

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E&P Division Summary

Sales volumes, average sales price (including the effects of derivatives instruments), and average costs for the E&P Division were as follows:

	For the Years Ended December 31,			
	2018	2017	Variance	Percent Change
Sales Volume (Bcfe)	507.1	407.2	99.9	24.5 %
Average Sales Price (per Mcfe)	$2.97	$2.66	$0.31	11.7 %
Lease Operating Expense (per Mcfe)	0.19	0.22	(0.03)	(13.6)%
Production, Ad Valorem, and Other Fees (per Mcfe)	0.06	0.07	(0.01)	(14.3)%
Transportation, Gathering and Compression (per Mcfe)	0.84	0.94	(0.10)	(10.6)%
Depreciation, Depletion and Amortization (DD&A) (per Mcfe)	0.89	1.00	(0.11)	(11.0)%
Average Costs (per Mcfe)	$1.98	$2.23	$(0.25)	(11.2)%
Average Margin (per Mcfe)	$0.99	$0.43	$0.56	130.2 %

Natural gas, NGLs, and oil revenue was $1,578 million for the year ended December 31, 2018, compared to $1,125 million for the year ended December 31, 2017. The increase was primarily due to the 24.5% increase in total sales volumes and 11.7% increase in average sales price.

The 24.5% increase in total sales volumes was primarily due to additional natural gas wells that were turned-in-line in the latter half of the 2017 period as well as throughout the 2018 period. These wells were primarily Marcellus and Utica wells. The production for 2018 also includes approximately 27 Bcfe of production related to assets that were sold during the year. For additional information, see Note 6 - Acquisitions and Dispositions in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K and incorporated herein.

The increase in average sales price was primarily the result of a $0.38 per Mcf increase in general natural gas market prices in the Appalachian basin during the current period, partially offset by a $0.03 per Mcfe decrease in the uplift from NGLs and condensate sales volumes when excluding the impact of hedging and the $0.04 increase in the realized loss on commodity derivative instruments related to the Company's hedging program.

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

- Lease operating expense decreased on a per unit basis due to the overall increase in sales volumes, primarily Utica, in the 2018. There were also significant decreases in routine well operating costs, repairs and maintenance expenses and employee costs, partially due to the sale of substantially all our shallow oil and gas properties in the first quarter. See Note 6 - Acquisitions and Dispositions in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information. In 2018, the company also deployed more in-house resources that maintained overall lease operating costs and increased operational efficiencies while significantly increasing production. The decreases were partially offset by increased water disposal costs, primarily in the first quarter of 2018, resulting from increased production volumes and gaps in the completions schedule for new wells.
- Transportation, gathering, and compression expense decreased on a per-unit basis primarily due to the 24.5% increase in sales volumes, and the shift towards dry Utica Shale production which has lower gathering costs and no processing costs. In the third quarter of 2018, CNX closed on the sale of substantially all of its Ohio Utica Joint Venture Assets in the wet gas Utica Shale areas (see Note 6 - Acquisitions and Dispositions in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for more information).
- Depreciation, depletion, and amortization decreased on a per-unit basis primarily due to a reduction in Marcellus Shale and Utica Shale rates as a result of an increase in the Company's associated reserves and an overall change in production mix.

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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.

in thousands (unless noted)	For the Years Ended December 31, 2018	2017	Variance	Percent Change
LIQUIDS				
NGLs:				
Sales Volume (MMcfe)	36,489	38,736	(2,247)	(5.8)%
Sales Volume (Mbbls)	6,081	6,456	(375)	(5.8)%
Gross Price ($/Bbl)	$27.30	$24.18	$3.12	12.9 %
Gross Revenue	$165,883	$156,132	$9,751	6.2 %
Oil:				
Sales Volume (MMcfe)	307	421	(114)	(27.1)%
Sales Volume (Mbbls)	51	70	(19)	(27.1)%
Gross Price ($/Bbl)	$59.34	$45.36	$13.98	30.8 %
Gross Revenue	$3,036	$3,179	$(143)	(4.5)%
Condensate:				
Sales Volume (MMcfe)	2,082	3,116	(1,034)	(33.2)%
Sales Volume (Mbbls)	347	519	(172)	(33.1)%
Gross Price ($/Bbl)	$50.58	$39.54	$11.04	27.9 %
Gross Revenue	$17,559	$20,531	$(2,972)	(14.5)%
GAS				
Sales Volume (MMcf)	468,226	364,893	103,333	28.3 %
Sales Price ($/Mcf)	$2.97	$2.59	$0.38	14.7 %
Gross Revenue	$1,391,459	$945,382	$446,077	47.2 %
Hedging Impact ($/Mcf)	$(0.15)	$(0.11)	$(0.04)	(36.4)%
Loss on Commodity Derivative Instruments - Cash Settlement	$(69,720)	$(41,174)	$(28,546)	(69.3)%

Selling, General and Administrative (SG&A) - Total Company

SG&A costs include costs such as overhead, including employee wages and benefit costs, short-term incentive compensation, costs of maintaining our headquarters, audit and other professional fees, and legal compliance expenses. SG&A costs also include noncash equity-based compensation expense.

SG&A costs were $135 million for the year ended December 31, 2018, compared to $93 million for the year ended December 31, 2017. SG&A costs increased primarily due to the Midstream Acquisition in January 2018, which now requires us to consolidate CNX Gathering and CNXM expenses as well as an increase in short-term incentive compensation expense. See Note 6 - Acquisitions and Dispositions in the Notes to the Audited Consolidated Financial Statements in Item 1 of this Form 10-K for additional information on the Midstream Acquisition. Prior to the Midstream Acquisition, CNX accounted for its interests in CNX Gathering and CNXM as an equity-method investment.

Unallocated Expense

Certain costs and expenses, such as other (income) expense, gain on sale of assets related to non-core assets, gain on previously held equity interest, loss on debt extinguishment, impairment of other intangible assets and income taxes are unallocated expenses and therefore are excluded from the per unit costs above as well as segment reporting. Below is a summary of these costs and expenses:

Other (Income) Expense

	For the Years Ended December 31,			
(in millions)	**2018**	**2017**	**Variance**	**Percent Change**
Other Income				
Right of Way Sales	$14	$2	$12	600.0 %
Royalty Income	15	10	5	50.0 %
Interest Income	—	9	(9)	(100.0)%
Other	8	6	2	33.3 %
Total Other Income	$37	$27	$10	37.0 %
Other Expense				
Bank Fees	$11	$13	$(2)	(15.4)%
Professional Services	7	6	1	16.7 %
Other Land Rental Expense	4	6	(2)	(33.3)%
Other Corporate Expense	—	6	(6)	(100.0)%
Total Other Expense	$22	$31	$(9)	(29.0)%
Total Other (Income) Expense	$(15)	$4	$(19)	(475.0)%

Gain on Sale of Assets

CNX recognized a gain on sale of assets of $157 million in the year ended December 31, 2018 compared to a gain of $188 million in the year ended December 31, 2017. During the year ended December 31, 2018, CNX closed on the sale of substantially all of its Ohio Utica Joint Venture Assets in the wet gas Utica Shale areas of Ohio and substantially all of its shallow oil and gas assets and certain CBM assets in Pennsylvania and West Virginia. The net gain on the sale of these assets was $136 million and is included in the Gain on Sale of Assets line on the Consolidated Statements of Income. During the year ended December 31, 2017, CNX closed on the sale of approximately 22,000 acres of surface land in Colorado, the sale of approximately 7,500 net undeveloped acres of the Marcellus Shale in Pennsylvania, the sale of approximately 11,100 net undeveloped acres of the Marcellus and Utica Shale in Pennsylvania, and the sale of approximately 6,300 net undeveloped acres of the Utica-Point Pleasant Shale in Ohio. The net gain on the sale of these assets was $165 million and is included in Gain on Sale of Assets in the Consolidated Statements of Income. The remaining decrease in the period-to-period comparison is due to various items that occurred throughout both periods, none of which were individually material. See Note 6 - Acquisitions and Dispositions in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.

Gain on Previously Held Equity Interest

CNX recognized a gain on previously held equity interest of $624 million in the year ended December 31, 2018 due to the Midstream Acquisition in January 2018. No such transactions occurred in the year ended December 31, 2017. See Note 6 - Acquisitions and Dispositions in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.

Loss on Debt Extinguishment

A loss on debt extinguishment of $54 million was recognized in the year ended December 31, 2018 compared to a loss on debt extinguishment of $2 million in the year ended December 31, 2017. During the year ended December 31, 2018, CNX purchased a portion of its 5.875% senior notes due in April 2022 at an average price equal to103.5% of the principal amount and redeemed the 8.00% senior notes due in April 2023 at a call price equal to 106.0% of the principal amount. In the year ended December 31, 2017, CNX purchased a portion of its 5.875% senior notes due in April 2022 at an average price equal to 99.5% of the principal amount, redeemed the 8.25% senior notes due in April 2020 at a call price equal to 101.375% of the principal amount, and redeemed the 6.375% senior notes due in March 2021 at a call price equal to 102.125% of the principal amount. See Note 14 - Long Term Debt in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.

Impairment of Other Intangible Assets
Intangible assets are tested for impairment whenever events or circumstances indicate that the carrying amount of an asset may not be recoverable. An impairment loss would be recognized when the carrying amount of the asset exceeds the estimated undiscounted future cash flows expected to result from the use of the asset and its eventual disposition. The impairment loss to be recorded would be the excess of the asset's carrying value over its fair value.

In connection with the Asset Exchange Agreement (AEA) with HG Energy transactions (See Note 6 - Acquisition and Dispositions in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information) that occurred during the year ended December 31, 2018, CNX determined that the carrying value of the other intangible asset - customer relationship exceeded its fair value, and an impairment of $19 million was included in Impairment of Other Intangible Assets in the Consolidated Statement of Income. No such transactions occurred in the prior period.

Income Taxes

The effective income tax rate for continuing operations was 19.6% for the year ended December 31, 2018, compared to (148.9)% for the year ended December 31, 2017. During the year ended December 31, 2018, CNX obtained a controlling interest in CNX Gathering LLC and, through CNX Gathering's ownership of the general partner, control over the CNXM. All of CNXM’s income is included in the Company's pre-tax income. However, the Company is not required to record income tax expense with respect to the portions of CNXM’s income allocated to the noncontrolling public limited partners of CNXM, which reduces the Company's effective tax rate in periods when the Company has consolidated pre-tax income and increases the Company's effective tax rate in periods when the Company has consolidated pre-tax loss. The effective tax rate for the year ended December 31, 2018 was lower than the U.S. federal statutory rate primarily due to the non-controlling interest in CNXM, the effect of the filing of a Federal net operating loss ("NOL") carryback for 2017 and 2016 resulting in a financial statement benefit of $23 million through the realization of the Federal NOLs at a 35% tax rate as a carryback versus the current 21% tax rate as a carryforward generating cash tax refunds to be received in 2019, the reversal of the alternative minimum tax ("AMT") credit sequestration valuation allowance, and the release of certain state valuation allowances as a result of a corporate reorganization during the year.

On December 22, 2017, the United States enacted the Tax Cuts and Jobs Act (the "Act") which, among other things, lowered the U.S. Federal income tax rate from 35% to 21%, repealed the corporate AMT, and provided for a refund of previously accrued AMT credits. The Company reclassified $102 million from Deferred Income Taxes to Recoverable Income Taxes on the Consolidated Balance Sheets in anticipation of a refund of 50% of the AMT credits expected to be received in 2019. The valuation allowance associated with the AMT credits of $12 million was released as the Internal Revenue Service ("IRS") announced that the AMT credits are no longer subject to government sequestration.

The Company recorded a net tax benefit to reflect the impact of the Act as of December 31, 2017, as it is required to reflect the change in the period in which the law is enacted. Largely, the benefits recorded in the prior period related to tax reform are in recognition of the revaluation of deferred tax assets and liabilities, a benefit of $115 million, and the benefit for reversal of valuation allowance previously recorded against AMT credits which are now refundable, a benefit of $154 million.

See Note 8 - 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,			
	2018	2017	Variance	Percent Change
Total Company Earnings Before Income Tax	$1,099	$119	$980	823.5 %
Income Tax Expense (Benefit)	$216	$(176)	$392	(222.7)%

Effective Income Tax Rate	19.6 %	(148.9)%	168.5%

TOTAL E&P DIVISION ANALYSIS for the year ended December 31, 2018 compared to the year ended December 31, 2017:

The E&P division had earnings from continuing operations before income tax of $245 million for the year ended December 31, 2018 compared to a loss from continuing operations before income tax of $63 million for the year ended December 31, 2017. Variances by individual operating segment are discussed below.

	For the Year Ended December 31, 2018					Difference to Year Ended December 31, 2017				
(in millions)	Marcellus	Utica	CBM	Other Gas	Total	Marcellus	Utica	CBM	Other Gas	Total
Natural Gas, NGLs and Oil Revenue	$903	$446	$213	$16	$1,578	$257	$229	$4	$(37)	$453
(Loss) Gain on Commodity Derivative Instruments	(40)	(20)	(9)	39	(30)	(10)	(21)	1	(207)	(237)
Purchased Gas Revenue	—	—	—	66	66	—	—	—	12	12
Other Operating Income	—	—	—	27	27	—	—	—	(42)	(42)
Total Revenue and Other Operating Income	863	426	204	148	1,641	247	208	5	(274)	186
Lease Operating Expense	41	30	22	2	95	9	11	(3)	(11)	6
Production, Ad Valorem, and Other Fees	18	7	7	1	33	3	2	—	(1)	4
Transportation, Gathering and Compression	320	52	48	4	424	64	7	(16)	(14)	41
Depreciation, Depletion and Amortization	230	143	77	11	461	8	59	(6)	(12)	49
Impairment of Exploration and Production Properties	—	—	—	—	—	—	—	—	(138)	(138)
Exploration and Production Related Other Costs	—	—	—	12	12	—	—	—	(36)	(36)
Purchased Gas Costs	—	—	—	65	65	—	—	—	12	12
Other Operating Expense	—	—	—	72	72	—	—	—	(40)	(40)
Selling, General, and Administrative Costs	—	—	—	112	112	—	—	—	19	19
Total Operating Costs and Expenses	609	232	154	279	1,274	84	79	(25)	(221)	(83)
Interest Expense	—	—	—	122	122	—	—	—	(39)	(39)
Total E&P Division Costs	609	232	154	401	1,396	84	79	(25)	(260)	(122)
Earnings (Loss) from Continuing Operations Before Income Tax	$254	$194	$50	$(253)	$245	$163	$129	$30	$(14)	$308

MARCELLUS SEGMENT

The Marcellus segment had earnings from continuing operations before income tax of $254 million for the year ended December 31, 2018 compared to earnings from continuing operations before income tax of $91 million for the year ended December 31, 2017.

	For the Years Ended December 31,			
	2018	**2017**	**Variance**	**Percent Change**
Marcellus Gas Sales Volumes (Bcf)	255.1	209.7	45.4	21.6 %
NGLs Sales Volumes (Bcfe)*	31.4	27.6	3.8	13.8 %
Condensate Sales Volumes (Bcfe)*	1.7	2.1	(0.4)	(19.0)%
Total Marcellus Sales Volumes (Bcfe)*	288.2	239.4	48.8	20.4 %
Average Sales Price - Gas (per Mcf)	$2.93	$2.50	$0.43	17.2 %
Loss on Commodity Derivative Instruments - Cash Settlement- Gas (per Mcf)	$(0.16)	$(0.14)	$(0.02)	(14.3)%
Average Sales Price - NGLs (per Mcfe)*	$4.55	$3.96	$0.59	14.9 %
Average Sales Price - Condensate (per Mcfe)*	$8.32	$6.44	$1.88	29.2 %
Total Average Marcellus Sales Price (per Mcfe)	$2.99	$2.57	$0.42	16.3 %
Average Marcellus Lease Operating Expenses (per Mcfe)	0.14	0.13	0.01	7.7 %
Average Marcellus Production, Ad Valorem, and Other Fees (per Mcfe)	0.07	0.07	—	— %
Average Marcellus Transportation, Gathering and Compression Costs (per Mcfe)	1.11	1.07	0.04	3.7 %
Average Marcellus Depreciation, Depletion and Amortization Costs (per Mcfe)	0.79	0.92	(0.13)	(14.1)%
Total Average Marcellus Costs (per Mcfe)	$2.11	$2.19	$(0.08)	(3.7)%
Average Margin for Marcellus (per Mcfe)	$0.88	$0.38	$0.50	131.6 %

*** 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 Marcellus segment had natural gas, NGLs and oil revenue of $903 million for the year ended December 31, 2018 compared to $646 million for the year ended December 31, 2017. The $257 million increase was primarily due to the 20.4% increase in total Marcellus sales volumes, including liquids, as well as the 16.3% increase in the total average Marcellus sales price in the period-to-period comparison. The increase in sales volumes was primarily due to additional wells being turned-in-line in the latter half of 2017 and throughout 2018.

The increase in the total average Marcellus sales price was primarily the result of the $0.43 per Mcf increase in average gas sales price and a $0.01 per Mcfe increase in the uplift from NGLs and condensate sales volume when excluding the impact of hedging, partially offset by the $0.02 per Mcfe increase in the loss on commodity derivative instruments resulting from the Company's hedging program. The notional amounts associated with these financial hedges represented approximately 206.7 Bcf of the Company's produced Marcellus gas sales volumes for the year ended December 31, 2018 at an average loss of $0.20 per Mcf. For the year ended December 31, 2017, these financial hedges represented approximately 177.6 Bcf at an average loss of $0.17 per Mcf.

Total operating costs and expenses for the Marcellus segment were $609 million for the year ended December 31, 2018 compared to $525 million for the year ended December 31, 2017. The increase in total dollars and decrease in unit costs for the Marcellus segment were due primarily to the following items:

•Marcellus lease operating expense was $41 million for the year ended December 31, 2018 compared to $32 million for the year ended December 31, 2017. The increase in total dollars was primarily due to an increase in water disposal costs in the current period due to increased production volumes along with proportionally more water being sent to disposal in the first quarter of 2018 instead of being reused in completions. The increase in unit costs was driven by the increase in total dollars, partially offset by the 20.4% increase in total Marcellus sales volumes.

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•Marcellus production, ad valorem, and other fees were $18 million for the year ended December 31, 2018 compared to $15 million for the year ended December 31, 2017. The increase in total dollars was primarily due to the increase in overall Marcellus production as well as a change in production mix by state as new wells are turned in line.

•Marcellus transportation, gathering and compression costs were $320 million for the year ended December 31, 2018 compared to $256 million for the year ended December 31, 2017. The $64 million increase in total dollars was primarily related to an increase in gathering, processing and utilized firm transportation costs due to increased volumes and increased processing costs due to a change in production mix which includes a greater proportion of higher cost wet gas. The increase in unit costs was due to the increased total dollars described above, partially offset by the 20.4% increase in Marcellus sales volumes.

•Depreciation, depletion and amortization costs attributable to the Marcellus segment were $230 million for the year ended December 31, 2018 compared to $222 million for the year ended December 31, 2017. These amounts included depletion on a unit of production basis of $0.79 per Mcf and $0.91 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 from continuing operations before income tax of $194 million for the year ended December 31, 2018 compared to earnings from continuing operations before income tax of $65 million for the year ended December 31, 2017.

	For the Years Ended December 31,			
	2018	**2017**	**Variance**	**Percent Change**
Utica Gas Sales Volumes (Bcf)	148.1	70.7	77.4	109.5 %
NGLs Sales Volumes (Bcfe)*	5.1	11.1	(6.0)	(54.1)%
Oil Sales Volumes (Bcfe)*	0.1	0.2	(0.1)	(50.0)%
Condensate Sales Volumes (Bcfe)*	0.4	1.0	(0.6)	(60.0)%
Total Utica Sales Volumes (Bcfe)*	153.7	83.0	70.7	85.2 %
Average Sales Price - Gas (per Mcf)	$2.82	$2.29	$0.53	23.1 %
(Loss) Gain on Commodity Derivative Instruments - Cash Settlement- Gas (per Mcf)	$(0.13)	$0.02	$(0.15)	(750.0)%
Average Sales Price - NGLs (per Mcfe)*	$4.54	$4.20	$0.34	8.1 %
Average Sales Price - Oil (per Mcfe)*	$9.46	$7.31	$2.15	29.4 %
Average Sales Price - Condensate (per Mcfe)*	$8.96	$6.88	$2.08	30.2 %
Total Average Utica Sales Price (per Mcfe)	$2.77	$2.63	$0.14	5.3 %
Average Utica Lease Operating Expenses (per Mcfe)	0.19	0.23	(0.04)	(17.4)%
Average Utica Production, Ad Valorem, and Other Fees (per Mcfe)	0.05	0.06	(0.01)	(16.7)%
Average Utica Transportation, Gathering and Compression Costs (per Mcfe)	0.34	0.54	(0.20)	(37.0)%
Average Utica Depreciation, Depletion and Amortization Costs (per Mcfe)	0.93	1.02	(0.09)	(8.8)%
Total Average Utica Costs (per Mcfe)	$1.51	$1.85	$(0.34)	(18.4)%
Average Margin for Utica (per Mcfe)	$1.26	$0.78	$0.48	61.5 %

***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 revenue of $446 million for the year ended December 31, 2018 compared to $217 million for the year ended December 31, 2017. The $229 million increase was due to the 85.2% increase in total Utica sales volumes as well as the 5.3% increase in total average Utica sales price. The 70.7 Bcfe increase in total Utica sales volumes was primarily due to additional wells turned-in-line beginning in the third quarter of 2017 and throughout the 2018 period, primarily in Monroe County, Ohio. The increase was partially offset by the sale of substantially all of CNX's Ohio Utica Joint Venture Assets, during the third quarter of 2018, in the wet gas Utica Shale areas (See Note 6 - Acquisitions and Dispositions in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for more information).

The increase in the total average Utica sales price was primarily due to the $0.53 increase in average gas sales price, offset, in part, by a $0.24 decrease in the uplift from NGLs and condensate sales volumes when excluding the impact of hedging. Part of the decrease in the uplift from NGLs and condensate sales volumes was due to the sale of the CNX's Ohio Utica Joint Venture Assets in the wet gas Utica Shale areas, as discussed above. There was also a $0.15 per Mcf decrease in the (loss) gain on commodity derivative instruments in the current period. The notional amounts associated with these financial hedges represented approximately 101.6 Bcf of the Company's produced Utica gas sales volumes for the year ended December 31, 2018 at an average loss of $0.20 per Mcf. For the year ended December 31, 2017, these financial hedges represented approximately 39.8 Bcf at an average gain of $0.04 per Mcf.

Total operating costs and expenses for the Utica segment were $232 million for the year ended December 31, 2018 compared to $153 million for the year ended December 31, 2017. The increase in total dollars and decrease in unit costs for the Utica segment are due to the following items:

•Utica lease operating expense increased to $30 million for the year ended December 31, 2018, compared to $19 million for the year ended December 31, 2017. The increase in total dollars was primarily due to higher well tending and water disposal costs in the current period associated with the additional sales volumes. The decrease in unit costs was due to the 85.2% increase in total Utica sales volumes.

•Utica production, ad valorem, and other fees were $7 million for the year ended December 31, 2018 compared to $5 million for the year ended December 31, 2017. The increase in total dollars was primarily due to the overall increase in Utica production as well as a change in production mix by state as new wells are turned-in-line. The decrease in unit costs was due to the increase in production volumes.

•Utica transportation, gathering and compression costs were $52 million for the year ended December 31, 2018 compared to $45 million for the year ended December 31, 2017. The $7 million increase in total dollars was primarily related to the increased production in the current period. The decrease in unit costs was due to the increase in total Utica sales volumes, predominantly dry Utica which does not require processing. In the third quarter of 2018, CNX closed on the sale of substantially all of its Ohio Utica Joint Venture Assets in the wet gas Utica Shale areas (see Note 6 - Acquisitions and Dispositions in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for more information).

•Depreciation, depletion and amortization costs attributable to the Utica segment were $143 million for the year ended December 31, 2018 compared to $84 million for the year ended December 31, 2017. These amounts included depletion on a unit of production basis of $0.93 per Mcf and $1.01 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 from continuing operations before income tax of $50 million for the year ended December 31, 2018 compared to earnings from continuing operations before income tax of $20 million for the year ended December 31, 2017.

	For the Years Ended December 31,									
	2018			2017			Variance		Percent Change	
CBM Gas Sales Volumes (Bcf)	60.3			65.4			(5.1	)	(7.8	)%
Average Sales Price - Gas (per Mcf)	$	3.53		$	3.19		$ 0.34		10.7	%
Loss on Commodity Derivative Instruments - Cash Settlement- Gas (per Mcf)	$	(0.15	)	$	(0.15	)	$ —		—	%
Total Average CBM Sales Price (per Mcf)	$	3.39		$	3.05		$ 0.34		11.1	%
Average CBM Lease Operating Expenses (per Mcf)	0.37			0.39			(0.02	)	(5.1	)%
Average CBM Production, Ad Valorem, and Other Fees (per Mcf)	0.12			0.11			0.01		9.1	%
Average CBM Transportation, Gathering and Compression Costs (per Mcf)	0.80			0.98			(0.18	)	(18.4	)%
Average CBM Depreciation, Depletion and Amortization Costs (per Mcf)	1.28			1.26			0.02		1.6	%
Total Average CBM Costs (per Mcf)	$	2.57		$	2.74		$ (0.17	)	(6.2	)%
Average Margin for CBM (per Mcf)	$	0.82		$	0.31		$ 0.51		164.5	%

The CBM segment had natural gas sales of $213 million for the year ended December 31, 2018 compared to $209 million for the year ended December 31, 2017. The $4 million increase was due to a 11.1% increase in the total average CBM sales price, offset, in part, by the 7.8% decrease in CBM gas sales volumes. The decrease in CBM sales volumes was primarily due to normal well declines, less drilling activity and the sale of certain CBM assets that were sold along with the majority of CNX's shallow oil and gas assets (See Note 6 - Acquisitions and Dispositions of the

Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information).

The total average CBM sales price increased due to the $0.34 per Mcf increase in the average gas sales price. The loss on commodity derivative instruments remained consistent year over year. The notional amounts associated with these financial hedges represented approximately 44.8 Bcf of the Company's produced CBM sales volumes for the year ended December 31, 2018 at an average loss of $0.20 per Mcf. For the year ended December 31, 2017, these financial hedges represented approximately 56.3 Bcf at an average loss of $0.17 per Mcf.

Total operating costs and expenses for the CBM segment were $154 million for the year ended December 31, 2018 compared to $179 million for the year ended December 31, 2017. The decrease in total dollars and decrease in unit costs were due to the following items:

•CBM lease operating expense was $22 million for the year ended December 31, 2018 compared to $25 million for the year ended December 31, 2017. The decrease in total dollars was primarily due to reductions in contract services. The decrease in unit costs was due to the decrease in total dollars as well as the decrease in CBM gas sales volumes.

•CBM production, ad valorem, and other fees remained consistent at $7 million for each of the years ended December 31, 2018 and December 31, 2017. Unit costs were negatively impacted by the decrease in CBM gas sales volumes.

•CBM transportation, gathering and compression costs were $48 million for the year ended December 31, 2018 compared to $64 million for the year ended December 31, 2017. The $16 million decrease was primarily related to a decrease in contractor services. The decrease was also due to a decrease in utilized firm transportation expense due to a new compressor station that began operating in the third quarter of 2017. This station allows CNX to flow more production through the Jewel Ridge Pipeline, which is treated as a capital lease. 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 $77 million for the year ended December 31, 2018 compared to $83 million for the year ended December 31, 2017. These amounts included depletion on a unit of production basis of $0.70 per Mcf and $0.78 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 from continuing operations before income tax of $253 million for the year ended December 31, 2018 compared to a loss from continuing operations before income tax of $239 million for the year ended December 31, 2017.

	For the Years Ended December 31,			
	2018	2017	Variance	Percent Change
Other Gas Sales Volumes (Bcf)	4.7	19.2	(14.5)	(75.5)%
Oil Sales Volumes (Bcfe)*	0.2	0.2	—	— %
Total Other Sales Volumes (Bcfe)*	4.9	19.4	(14.5)	(74.7)%
Average Sales Price - Gas (per Mcf)	$2.91	$2.69	$0.22	8.2 %
(Loss) Gain on Commodity Derivative Instruments - Cash Settlement- Gas (per Mcf)	$(0.13)	$(0.14)	$0.01	7.1 %
Average Sales Price - Oil (per Mcfe)*	$10.09	$7.75	$2.34	30.2 %
Total Average Other Sales Price (per Mcfe)	$3.09	$2.62	$0.47	17.9 %
Average Other Lease Operating Expenses (per Mcfe)	0.42	0.63	(0.21)	(33.3)%
Average Other Production, Ad Valorem, and Other Fees (per Mcfe)	0.04	0.12	(0.08)	(66.7)%
Average Other Transportation, Gathering and Compression Costs (per Mcfe)	0.87	0.90	(0.03)	(3.3)%
Average Other Depreciation, Depletion and Amortization Costs (per Mcfe)	1.49	1.05	0.44	41.9 %
Total Average Other Costs (per Mcfe)	$2.82	$2.70	$0.12	4.4 %
Average Margin for Other (per Mcfe)	$0.27	$(0.08)	$0.35	437.5 %

***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, impairment of exploration and production properties and other operational activity not assigned to a specific segment.

Other Gas sales volumes are primarily related to CNX's remaining shallow oil and gas production. CNX sold substantially all of these assets on March 30, 2018 (See Note 6 - Acquisitions and Dispositions of the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information). Natural gas, NGLs and oil revenue related to the Other Gas segment were $16 million for the year ended December 31, 2018 compared to $53 million for the year ended December 31, 2017. The decrease in natural gas and oil revenue resulted from the 74.7% decrease in total Other Gas sales volumes relating to the asset sale. Total exploration and production costs related to these other sales were $18 million for the year ended December 31, 2018 compared to $56 million for the year ended December 31, 2017.

The Other Gas segment recognized an unrealized gain on commodity derivative instruments of $40 million as well as cash settlements paid of $1 million for the year ended December 31, 2018. For the year ended December 31, 2017, the Company recognized an unrealized gain on commodity derivative instruments of $248 million as well as cash settlements paid of $2 million. The unrealized gain on commodity derivative instruments represents changes in the fair value of all the Company's existing commodity derivative hedges on a mark-to-market basis.

Purchased Gas

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 revenue was $66 million for the year ended

December 31, 2018 compared to $54 million for the year ended December 31, 2017. Purchased gas costs were $65 million for the year ended December 31, 2018 compared to $53 million for the year ended December 31, 2017. The period-to-period increase in purchased gas revenue was primarily due to the increase in market prices, partially offset by the decrease in purchased gas sales volumes.

	For the Years Ended December 31,			
	2018	2017	Variance	Percent Change
Purchased Gas Sales Volumes (in billion cubic feet)	20.5	22.0	(1.5)	(6.8)%
Average Sales Price (per Mcf)	$3.23	$2.44	$0.79	32.4 %
Average Cost (per Mcf)	$3.17	$2.39	$0.78	32.6 %

Other Operating Income

Other operating income was $27 million for the year ended December 31, 2018 compared to $69 million for the year ended December 31, 2017. The $42 million decrease was primarily due to the following items:

	For the Years Ended December 31,			
(in millions)	2018	2017	Variance	Percent Change
Equity in Earnings of Affiliates	$5	$50	$ (45)	(90.0)%
Gathering Income	10	11	(1)	(9.1)%
Water Income	11	5	6	120.0 %
Other	1	3	(2)	(66.7)%
Total Other Operating Income	$27	$69	$ (42)	(60.9)%

- Equity in Earnings of Affiliates decreased $45 million primarily due to the consolidation of CNX Gathering and CNXM in the current year. See Note 6 - Acquisitions and Dispositions in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.
- Water Income increased $6 million due to increased sales of freshwater to third-parties for hydraulic fracturing.

Impairment of Exploration and Production Related Properties

Impairment of Exploration and Production Properties of $138 million for the year ended December 31, 2017 related to an impairment in the carrying value of Knox Energy in the first quarter of 2017. See Note 1 - Significant Accounting Policies and Note 6 - Acquisitions and Dispositions in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information. No such impairments occurred in the year ended December 31, 2018.

Exploration and Production Related Other Costs

Exploration and production related other costs were $12 million for the year ended December 31, 2018 compared to $48 million for the year ended December 31, 2017. The $36 million decrease in costs was primarily related to the following items:

	For the Years Ended December 31,			
(in millions)	2018	2017	Variance	Percent Change
Lease Expiration Costs	$5	$40	$ (35)	(87.5)%
Land Rentals	4	4	—	— %
Other	3	4	(1)	(25.0)%
Total Exploration and Production Related Other Costs	$12	$48	$ (36)	(75.0)%

- Lease Expiration Costs relate to leases where the primary term expired or will expire within the next 12 months. The $35 million decrease in the year ended December 31, 2018, was primarily due to leases in both Monroe and Noble County, Ohio that were no longer in the Company's future drilling plans, so they were not renewed in the 2017 period.

Other Operating Expenses

Other operating expense was $72 million for the year ended December 31, 2018 compared to $112 million for the year ended December 31, 2017. The $40 million decrease in the period-to-period comparison was made up of the following items:

	For the Years Ended December 31,			
	2018	2017	Variance	Percent Change
Idle Rig Expense	$5	$41	$ (36)	(87.8)%
Unutilized Firm Transportation and Processing Fees	42	50	(8)	(16.0)%
Severance Expense	1	1	—	— %
Insurance Expense	3	3	—	— %
Litigation Settlements	4	3	1	33.3 %
Other	17	14	3	21.4 %
Total Other Operating Expense	$72	$112	$ (40)	(35.7)%

- Idle Rig Expense relates to the temporary idling of some of the Company's natural gas rigs. The total idle rig expense incurred by the Company decreased $36 million in the period-to-period comparison due to contracts that expired in the current period. Additionally, the total idle rig expense decreased in the period-to-period comparison due to a settlement that was reached with a former joint-venture partner that resulted in CNX recording additional expense in the year ended December 31, 2017.
- Unutilized Firm Transportation and Processing Fees represent pipeline transportation capacity obtained to enable gas production to flow uninterrupted as sales volumes increase, as well as additional processing capacity for NGLs. The decrease in the period-to-period comparison was primarily due to the increase 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 Income in other operating income above.

Selling, General and Administrative

SG&A costs represent direct charges for the management and operation of CNX's E&P division. SG&A costs were $112 million for the year ended December 31, 2018 compared to $93 million for the year ended December 31, 2017. Refer to the discussion of total company SG&A costs contained in the section "Net Income Attributable to CNX Resources Shareholders" of this Form 10-K for a detailed cost explanation.

Interest Expense

Interest expense of $122 million was recognized in the year ended December 31, 2018 compared to $161 million in the year ended December 31, 2017. The $39 million decrease was primarily due to a reduction in higher cost long-term debt, resulting from the $411 million purchase of the outstanding 5.875% senior notes due in April 2022 and the $500 million purchase of the outstanding 8% senior notes due in April 2023 in the year ended December 31, 2018, offset, in part, by additional borrowings on the CNX credit facility. In the year ended December 31, 2017, CNX purchased $144 million of its outstanding 5.875% senior notes due in April 2022. See Note 14 - Long-Term Debt in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.

TOTAL MIDSTREAM DIVISION ANALYSIS for the period January 3, 2018 through December 31, 2018:

CNX's Midstream Division's principal activity is the ownership, operation, development and acquisition of natural gas gathering and other midstream energy assets of CNX Gathering and CNXM, which provide natural gas gathering services for the Company's produced gas, as well as for other independent third-parties in the Marcellus Shale and Utica Shale in Pennsylvania and West Virginia. Excluded from the Midstream Division are the gathering assets and operations of CNX that have not been contributed to CNX Gathering and CNXM.

On January 3, 2018, CNX completed the Midstream Acquisition (See Note 6 - Acquisitions and Dispositions in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information). CNX Gathering holds all of the interests in CNX Midstream GP, LLC, which holds the general partner interest and incentive distribution rights in CNXM. As a result of this transaction, CNX owns and controls 100% of CNX Gathering, making CNXM a single-sponsor master limited partnership and thus the Company consolidates both CNX Gathering and CNXM commencing on January 3, 2018. Prior to the acquisition, CNX accounted for its interests in CNX Gathering and CNXM as an equity-method investment and as such a period-to-period analysis is not meaningful.

(in millions)	**For the period January 3, 2018 through December 31, 2018**
Midstream Revenue - Related Party	$ 168
Midstream Revenue - Third Party	90
Total Revenue	$ 258
Transportation, Gathering and Compression	$ 47
Depreciation, Depletion and Amortization	32
Selling, General, and Administrative Costs	23
Total Operating Costs and Expenses	102
Gain on Asset Sales	(2)
Interest Expense	24
Total Midstream Division Costs	124
Earnings from Continuing Operations Before Income Tax	$ 134

Midstream Revenue

Midstream revenue consists of revenue related to volumes gathered on behalf of CNX and other third-party natural gas producers. CNXM charges a higher fee for natural gas that is shipped on its wet system compared to gas shipped through its dry system. CNXM revenue can also be impacted by the relative mix of gathered volumes by area, which may vary dependent upon delivery point and may change dynamically depending on commodity prices at time of shipment.

The table below summaries volumes gathered by gas type for the period January 3, 2018 through December 31, 2018.

	TOTAL
Dry Gas (BBtu/d) (*)	740
Wet Gas (BBtu/d) (*)	661
Other (BBtu/d) (*)(**)	73
Total Gathered Volumes	1,474

(*) Classification as dry or wet is based upon the shipping destination of the related volumes. Because CNXM's customers have the option to ship a portion of their natural gas to destinations associated with either our wet system or our dry system, due to any number of factors, volumes may be classified as “wet” in one period and as “dry” in the comparative period.
(**) Includes condensate handling and third-party volumes under high-pressure short-haul agreements.

Transportation, Gathering and Compression

Transportation, Gathering and Compression costs were $47 million for the period January 3, 2018 through December 31, 2018 and are comprised of items directly related to the cost of gathering natural gas at the wellhead and transporting it to interstate pipelines or other local sales points. These costs include items such as electrical compression, repairs and maintenance, supplies, treating and contract services.

SG&A Expense

SG&A expense is comprised of direct charges for the management and operation of CNXM assets. Refer to the discussion of total Company SG&A costs contained in the section "Net Income Attributable to CNX Resources Shareholders" of this Form 10-K for a detailed cost explanation.

Depreciation, Depletion and Amortization

Depreciation expense is recognized on gathering and other equipment on a straight-line basis, with useful lives ranging from 25 years to 40 years.

Gain on Asset Sales

During the period January 3, 2018 through December 31, 2018, CNXM sold property and equipment to an unrelated third- party for $6 million in cash proceeds, resulting in a gain of $2 million.

Interest Expense

Interest expense is comprised of interest on the outstanding balance under CNXM's senior notes due 2026 and its revolving credit facility. Interest expense was $24 million for the period January 3, 2018 through December 31, 2018.

Results of Operations: ***Year Ended December 31, 2017 Compared with the Year Ended December 31, 2016***

Net Income (Loss)

CNX reported net income of $381 million, or earnings per diluted share of $1.65, for the year ended December 31, 2017, compared to a net loss of $848 million, or a loss per diluted share of $3.70, for the year ended December 31, 2016.

	For the Years Ended December 31,		
(Dollars in thousands)	**2017**	**2016**	**Variance**
Income (Loss) from Continuing Operations	$295,039	$(550,945)	$845,984
Income (Loss) from Discontinued Operations, net	85,708	(297,157)	382,865
Net Income (Loss)	$380,747	$(848,102)	$1,228,849

CNX currently consists of two principal business divisions: Exploration and Production (E&P) and Midstream. CNX's Midstream Division was the result of the Midstream Acquisition that occurred on January 3, 2018 (See Note 6 - Acquisitions and Dispositions in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information). Prior to the acquisition, CNX accounted for its interests in CNX Gathering and CNXM as an equity-method investment which is how it appears in the 2017 and 2016 analysis.

The principal activity of CNX, prior to the Midstream Acquisition, was to produce pipeline quality natural gas for sale primarily to gas wholesalers. The Company's reportable segments were Marcellus Shale, Utica Shale, Coalbed Methane, and Other Gas.

CNX had a total company earnings from continuing operations before income tax of $119 million for the year ended December 31, 2017, compared to a loss from continuing operations before income tax of $585 million for the year ended December 31, 2016. Included in the 2017 earnings from continuing operations before income tax was an unrealized gain on commodity derivative instruments of $248 million and a gain on sale of assets of $188 million, partially offset by $138 million of expense relating to the impairment in carrying value of Knox Energy LLC and Coalfield Pipeline Company (collectively, "Knox Energy"). See Note 1 - Significant Accounting Policies in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information. Included in the 2016 net loss from continuing operations before income tax was an unrealized loss on commodity derivative instruments of $386 million, partially offset by a gain on sale of assets of $14 million.

Natural gas, NGLs, and oil revenue was $1,125 million for the year ended December 31, 2017 compared to $793 million for the year ended December 31, 2016. The increase was primarily due to the 3.2% increase in total sales volumes.

Sales volumes, average sales price (including the effects of derivative instruments), and average costs for active operations in the period-to-period comparison were as follows:

	For the Years Ended December 31,			
	2017	**2016**	**Variance**	**Percent Change**
Sales Volume (Bcfe)	407.2	394.4	12.8	3.2 %
Average Sales Price (per Mcfe)	$2.66	$2.63	$0.03	1.1 %
Lease Operating Expense	0.22	0.24	(0.02)	(8.3)%
Production, Ad Valorem, and Other Fees	0.07	0.08	(0.01)	(12.5)%
Transportation, Gathering and Compression	0.94	0.95	(0.01)	(1.1)%
Depreciation, Depletion and Amortization (DD&A)	1.00	1.05	(0.05)	(4.8)%
Average Costs (per Mcfe)	$2.23	$2.32	$(0.09)	(3.9)%

Average Margin	$0.43	$0.31	$0.12	38.7 %

The increase in average sales price was primarily the result of the $0.67 per Mcf increase in general natural gas market prices in the Appalachian basin during the 2017 period and the $0.08 per Mcfe increase in the uplift from NGLs and condensate sales volumes when excluding the impact of hedging, partially offset by the $0.81 per Mcf decrease in the realized (loss) gain on commodity derivative instruments related to the Company's hedging program.

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

- Depreciation, depletion, and amortization decreased on a per-unit basis primarily due to a reduction in Marcellus rates as a result of an increase in the Company's Marcellus reserves. See Note 10 - Property, Plant, and Equipment in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional details.
- Lease operating expense decreased on a per unit basis due to a decrease in well tending costs and salt water disposal costs, as well as a decrease in both Company operated and joint venture operated repairs and maintenance costs.

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.

in thousands (unless noted)	For the Years Ended December 31, 2017	2016	Variance	Percent Change
LIQUIDS				
NGLs:				
Sales Volume (MMcfe)	38,736	40,260	(1,524)	(3.8)%
Sales Volume (Mbbls)	6,456	6,710	(254)	(3.8)%
Gross Price ($/Bbl)	$24.18	$14.52	$9.66	66.5 %
Gross Revenue	$156,132	$97,580	$58,552	60.0 %
Oil:				
Sales Volume (MMcfe)	421	410	11	2.7 %
Sales Volume (Mbbls)	70	68	2	2.9 %
Gross Price ($/Bbl)	$45.36	$36.90	$8.46	22.9 %
Gross Revenue	$3,179	$2,521	$658	26.1 %
Condensate:				
Sales Volume (MMcfe)	3,116	4,964	(1,848)	(37.2)%
Sales Volume (Mbbls)	519	828	(309)	(37.3)%
Gross Price ($/Bbl)	$39.54	$27.48	$12.06	43.9 %
Gross Revenue	$20,531	$22,748	$(2,217)	(9.7)%
GAS				
Sales Volume (MMcf)	364,893	348,753	16,140	4.6 %
Sales Price ($/Mcf)	$2.59	$1.92	$0.67	34.9 %
Gross Revenue	$945,382	$670,823	$274,559	40.9 %
Hedging Impact ($/Mcf)	$(0.11)	$0.70	$(0.81)	(115.7)%
(Loss) Gain on Commodity Derivative Instruments - Cash Settlement	$(41,174)	$245,212	$(286,386)	(116.8)%

Selling, General and Administrative

SG&A costs include costs such as overhead, including employee wages and benefit costs, short-term incentive compensation, costs of maintaining our headquarters, audit and other professional fees, and legal compliance expenses. SG&A costs also includes noncash equity-based compensation expense.

SG&A costs were $93 million for the year ended December 31, 2017, compared to $105 million for the year ended December 31, 2016. SG&A costs decreased due to a decrease in employee wages and benefit costs in 2017 related to a reduction in headcount as well as a decrease in equity-based compensation expense.

Unallocated Expense

Certain costs and expenses such as other expense, gain on sale of assets related to non-core assets, loss on debt extinguishment and income taxes are unallocated expenses and therefore are excluded from the per unit costs above as well as segment reporting. Below is a summary of these costs and expenses:

Other Expense

	For the Years Ended December 31,			
(in millions)	**2017**	**2016**	**Variance**	**Percent Change**
Other Income				
Right of Way Sales	$2	$15	$(13)	(86.7)%
Royalty Income	10	10	—	—%
Interest Income	9	—	9	100.0%
Other	6	4	2	50.0%
Total Other Income	$27	$29	$(2)	(6.9)%
Other Expense				
Professional Services	$6	$7	$(1)	(14.3)%
Bank Fees	13	13	—	—%
Other Land Rental Expense	6	5	1	20.0%
Other Corporate Expense	6	9	(3)	(33.3)%
Total Other Expense	$31	$34	$(3)	(8.8)%
Total Other Expense	$4	$5	$(1)	(20.0)%

Gain on Sale of Assets

CNX recognized a gain on sale of assets of $188 million in the year ended December 31, 2017 compared to a gain of $14 million in the year ended December 31, 2016. The $174 million increase was primarily due to sale of approximately 22,000 acres of surface land in Colorado, the sale of approximately 7,500 net undeveloped acres of the Marcellus Shale in Pennsylvania, the sale of approximately 11,100 net undeveloped acres of the Marcellus and Utica Shale in Pennsylvania, and the sale of approximately 6,300 net undeveloped acres of the Utica-Point Pleasant Shale in Ohio in the year ended December 31, 2017. No individually significant transactions occurred in the year ended December 31, 2016. See Note 6 - Acquisitions and Dispositions in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.

Loss on Debt Extinguishment

Loss on debt extinguishment of $2 million was recognized in the year ended December 31, 2017 due to the purchase of a portion of the 5.875% senior notes due in April 2022 at an average price equal to 99.5% of the principal amount, the redemption of the 8.25% senior notes due in April 2020 at a call price equal to 101.375% of the principal amount, and the redemption of the 6.375% senior notes due in March 2021 at a call price equal to 102.125% of the principal amount. See Note 14 - Long-Term Debt in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.

Income Taxes

The effective income tax rate for continuing operations was (148.9)% for the year ended December 31, 2017, compared to 6.0 % for the year ended December 31, 2016. During the year ended December 31, 2016, CNX 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. Some of the factors contributing to the refunds received during 2016 put pressure on deferred tax assets related to alternative minimum tax credits. As management could not demonstrate sufficient positive evidence to ensure realizability of these assets, the Company recorded a valuation allowance of $167 million at December 31, 2016 on alternative minimum tax credits as well as an additional $38 million valuation allowance was recorded at December 31, 2016 against state deferred tax assets, as well as federal charitable contributions and foreign tax credit carry-forwards.

On December 22, 2017, the United States enacted the Tax Cuts and Jobs Act (the "Act") which, among other things, lowered the U.S. Federal tax rate from 35% to 21%, repealed the corporate alternative minimum tax, and provided for a refund of previously accrued alternative minimum tax credits. The Company recorded a net tax benefit to reflect the impact of the Act as of December 31, 2017, as it is required to reflect the change in the period in which the law is enacted. Largely, the benefits recorded in the 2017 period related to tax reform are in recognition of the revaluation of deferred tax assets and liabilities, a benefit of $115 million, and the benefit for reversal of valuation allowance previously recorded against alternative minimum tax credits which are now refundable, a benefit of $154 million.

See Note 8 - 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,			
	2017	**2016**	**Variance**	**Percent Change**
Total Company Earnings (Loss) Before Income Tax	$119	$(585)	$704	(120.3)%
Income Tax Benefit	$(176)	$(34)	$(142)	417.6 %
Effective Income Tax Rate	(148.9)%	6.0 %	(154.9)%	

TOTAL E&P DIVISION ANALYSIS for the year ended December 31, 2017 compared to the year ended December 31, 2016:

The E&P division had a loss from continuing operations before income tax of $63 million for the year ended December 31, 2017 compared to a loss from continuing operations before income tax of $594 million for the year ended December 31, 2016. Variances by individual operating segment are discussed below.

	For the Year Ended December 31, 2017					Difference to Year Ended December 31, 2016				
(in millions)	**Marcellus**	**Utica**	**CBM**	**Other Gas**	**Total**	**Marcellus**	**Utica**	**CBM**	**Other Gas**	**Total**
Natural Gas, NGLs and Oil Revenue	$646	$217	$209	$ 53	$1,125	$231	$54	$34	$13	$332
(Loss) Gain on Commodity Derivative Instruments	(30)	1	(10)	246	207	(177)	(28)	(62)	615	348
Purchased Gas Revenue	—	—	—	54	54	—	—	—	11	11
Other Operating Income	—	—	—	69	69	—	—	—	4	4
Total Revenue and Other Operating Income	616	218	199	422	1,455	54	26	(28)	643	695
Lease Operating Expense	32	19	25	13	89	(2)	(3)	—	(2)	(7)
Production, Ad Valorem, and Other Fees	15	5	7	2	29	(2)	—	1	(1)	(2)
Transportation, Gathering and Compression	256	45	64	18	383	28	(6)	(8)	(5)	9
Depreciation, Depletion and Amortization	222	84	83	23	412	11	(2)	(3)	(14)	(8)
Impairment of Exploration and Production Properties	—	—	—	138	138	—	—	—	138	138
Exploration and Production Related Other Costs	—	—	—	48	48	—	—	—	33	33
Purchased Gas Costs	—	—	—	53	53	—	—	—	10	10
Other Operating Expense	—	—	—	112	112	—	—	—	23	23
Selling, General and Administrative Costs	—	—	—	93	93	—	—	—	(11)	(11)
Total Operating Costs and Expenses	525	153	179	500	1,357	35	(11)	(10)	171	