ONE COMPANY.
DELIVERING ON **VALUE**.

ONEOK

2017 ANNUAL REPORT

ONEOK, Inc. (pronounced ONE-OAK) (NYSE: OKE) is a leading midstream service provider and owner of one of the nation's premier natural gas liquids (NGL) systems, connecting NGL supply in the Mid-Continent, Permian and Rocky Mountain regions with key market centers and an extensive network of natural gas gathering, processing, storage and transportation assets.

ONEOK is a Fortune 500 company and is included in Standard & Poor's (S&P) 500 index. For information about ONEOK, visit www.oneok.com. For the latest news about ONEOK, find us on LinkedIn, Facebook and Twitter.

ONEOK **FINANCIAL HIGHLIGHTS**

Years ended Dec. 31		2017		2016		2015
Consolidated financial information *(millions of dollars)*						
Operating income	$	1,380.9	$	1,285.7	$	996.2
Net income[1]	$	593.5	$	743.5	$	379.2
Net income attributable to ONEOK, Inc.[1]	$	387.8	$	352.0	$	245.0
Total assets	$	16,845.9	$	16,138.8	$	15,446.1
Common stock data						
Shares outstanding at Dec. 31		388,703,543		210,681,661		209,731,028
Data per common share						
Earnings per share from continuing operations – diluted[1]	$	1.29	$	1.67	$	1.19
Dividends paid	$	2.72	$	2.46	$	2.43
Market price range						
High	$	58.83	$	59.03	$	51.07
Low	$	47.41	$	19.62	$	18.93
Year-end	$	53.45	$	57.41	$	24.66

[1] Financial results for 2017 include one-time noncash charges of $141.3 million, or 47 cents per diluted share, related to the enactment of the Tax Cuts and Jobs Act, noncash impairment charges of $20.2 million, or 4 cents per diluted share, and $50 million, or 10 cents per diluted share, in one-time and ONEOK and ONEOK Partners merger transaction-related costs.

RECONCILIATION OF INCOME FROM CONTINUING OPERATIONS TO ADJUSTED EBITDA AND DISTRIBUTABLE CASH FLOW – UNAUDITED (MILLIONS OF DOLLARS)

		2017		2016		2015
Income from continuing operations	$	593.5	$	745.6	$	385.3
Interest expense, net of capitalized interest		485.7		469.7		416.8
Depreciation and amortization		406.3		391.6		354.6
Income taxes		447.3		212.4		136.6
Impairment charges		20.2		—		264.3
Noncash compensation expense		13.4		32.0		13.8
Other noncash items and equity AFUDC[2]		20.5		(1.4)		8.1
Adjusted EBITDA[3]		1,986.9		1,849.9		1,579.5
Interest expense		(485.7)		(469.7)		(416.8)
Maintenance capital		(147.2)		(112.4)		(115.6)
Equity in net earnings from investments, excluding noncash impairment charges		(159.3)		(139.7)		(125.3)
Distributions received from unconsolidated affiliates		196.1		196.7		155.9
Other		(6.1)		(2.5)		(5.9)
Distributable cash flow[3]	$	1,384.7	$	1,322.3	$	1,071.8

[2] 2017 includes ONEOK's April 2017 contribution to the ONEOK Foundation of 20,000 shares of Series E Preferred Stock, with an aggregate value of $20 million.

[3] 2017 includes transaction-related pretax cash costs of $30 million associated with the ONEOK and ONEOK Partners merger transaction.

LETTER TO OUR INVESTORS

AS **ONE**, WE REMAIN **STRONG**

At ONEOK, we are opportunity driven and value focused.

As crude oil and natural gas producers continue to experience significant improvements in efficiency and technology, we have proven time and time again that we are committed to investing in energy infrastructure alongside our customers, while providing long-term value to our stakeholders.

On June 30, 2017, ONEOK completed the merger transaction with ONEOK Partners, the operating company and master limited partnership that has served us well. ONEOK emerged from the transaction as a company with an approximately $30 billion enterprise value, and while our corporate structure may have changed, our core business operations and strategies have remained the same:

- Operate our existing assets safely, reliably and in an environmentally responsible and sustainable manner.
- Maintain a disciplined approach to increasing fee-based earnings, proactively managing our balance sheet and maintaining our investment-grade credit ratings.
- Deliver quality service to our customers and focus on organic, attractive-return growth opportunities that enhance our company's ability to provide the most value for our investors.
- Attract and retain a diverse group of employees to execute on our key strategies.

The transaction combined two successful companies, further strengthening our balance sheet, lowering our cost of funding and increasing our access to capital. Since the closing of the merger, we have announced more than $4 billion of investments for new capital-growth projects that are expected to meet the needs of producers and customers who need our midstream services to deliver their products to the marketplace.

We expect these projects to further strengthen our position as a premier midstream service provider and generate stable and growing cash flows through fee-based earnings.

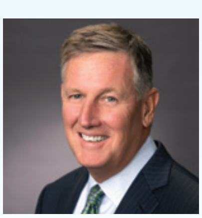
The merger also provided a clearer view into future growth and value to investors, as we expect annual dividend increases of 9 to 11 percent through 2021.

You'll learn more about our 2017 financial performance and slate of announced projects later in this report.

This year of tremendous success in a challenging environment is attributable to the hard work of our dedicated employees, who continue to uphold our company values and execute on our key strategies. Their commitment to operating reliably and responding to those in need was on full display this past year as we, along with our neighbors on the Gulf Coast, weathered Hurricane Harvey. Their preparedness, dedication, quick thinking and resilience ensured that we continued to operate safely and provided needed services to our customers and support to nearby communities during the storm.

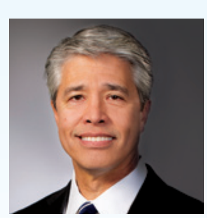
Thank you to our board of directors for its guidance as we continue executing on our growth strategy. And, thank you to Kevin McCarthy, who resigned from the board in May 2017 due to increased responsibilities as chairman of Kayne Anderson Acquisition Corp. Kevin's experience and leadership were invaluable as we navigated the energy industry's most recent downturn.

And finally, thank you, investors, for your continued trust and investment in ONEOK.



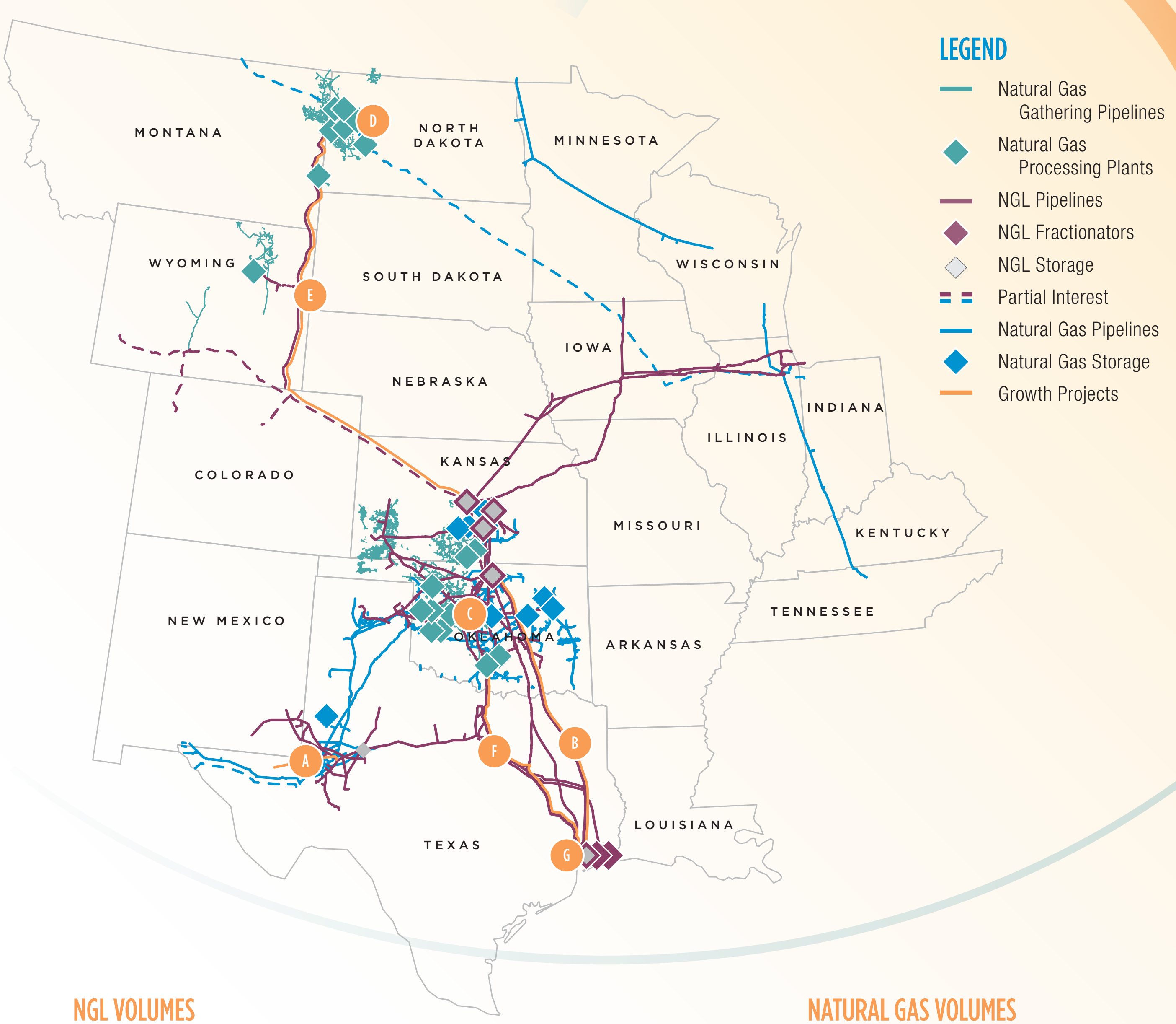
March 13, 2018

John W. Gibson
Chairman



Terry K. Spencer
President and
Chief Executive Officer

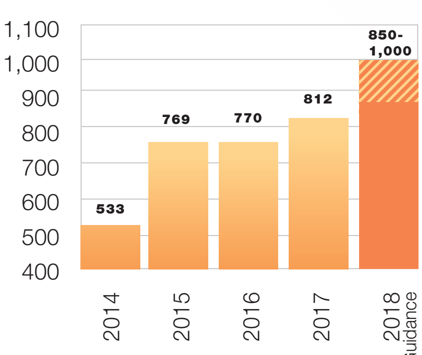
OUR **ASSETS**



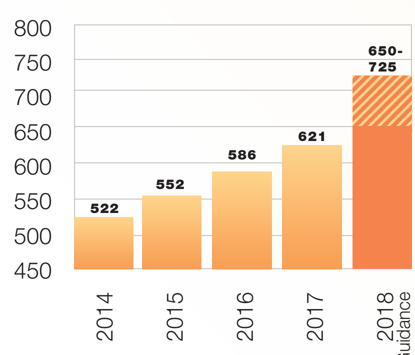
NGL VOLUMES

in thousand barrels per day (MBbl/d)

GATHERED VOLUME



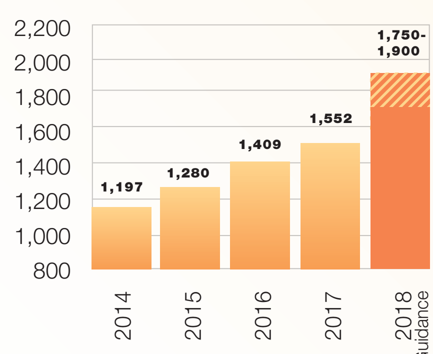
FRACTIONATED VOLUME



NATURAL GAS VOLUMES

in million cubic feet per day (MMcf/d)

PROCESSED VOLUME



INVESTING $4 BILLION IN NEW INFRASTRUCTURE

Driven by improved drilling economics and efficiencies by crude oil and natural gas producers in some of the fastest growing shale plays in the country, we announced more than $4 billion of attractive-return, capital-growth projects in 2017 and early 2018.

The announced projects will strengthen our existing network of approximately 38,000 miles of natural gas liquids (NGL) and natural gas pipelines, 20 natural gas processing plants, seven NGL fractionators and numerous NGL and natural gas storage facilities in high-producing basins spanning from the Canadian border to the Texas Gulf Coast.

We operate one of the most extensive NGL businesses in the country, where we collect raw NGLs from nearly 200 processing plants, fractionate them into finished products and deliver them to customers.

Our NGL services are primarily fee-based and connect plants in the Mid-Continent, Permian and Rocky Mountain regions to key NGL market centers in Conway, Kansas, and Mont Belvieu, Texas.

As the need for additional infrastructure increases, we have announced plans to construct the following projects:

- West Texas LPG system expansion;
- Sterling III Pipeline and Oklahoma NGL gathering system expansions;
- Canadian Valley plant expansion;
- Demicks Lake plant;
- Elk Creek Pipeline;
- Arbuckle II Pipeline; and
- MB-4 NGL fractionator and storage.

Once completed, we expect these projects will provide critical and needed capacity for our customers. In 2018, growing ethane demand remains a strong expected catalyst of volume and earnings growth. We expect ethane demand, driven by new, world-scale petrochemical facility completions and increased exports from the Texas Gulf Coast, to result in an increase of approximately $100 million of incremental adjusted EBITDA during 2018 compared with 2017.

A **West Texas LPG System Expansion | Expected Completion: Third Quarter 2018 | Approximate Cost: $160 million***
A 120-mile pipeline lateral and related infrastructure with capacity to transport 110,000 barrels per day (bpd) of raw NGLs from the Delaware Basin in West Texas. This is an 80-20 joint venture in which ONEOK is the operator and owns the controlling interest.

B **Sterling III Pipeline and Oklahoma NGL Gathering System Expansions | Expected Completion: Fourth Quarter 2018 | Approximate Cost: $130 million**
Increasing capacity on Sterling III Pipeline to transport up to 250,000 bpd of raw NGLs or NGL purity products from the Mid-Continent to Mont Belvieu, Texas. Expanding related gathering system to accommodate an incremental 100,000 bpd of expected NGL supply to be added by the end of 2018.

C **Canadian Valley Plant Expansion | Expected Completion: Fourth Quarter 2018 | Approximate Cost: $160 million**
Increasing natural gas processing capacity to 400 million cubic feet per day (MMcf/d) from 200 MMcf/d at the existing Canadian Valley plant in Canadian County, Oklahoma.

D **Demicks Lake Plant | Expected Completion: Fourth Quarter 2019 | Approximate Cost: $400 million**
A 200-MMcf/d natural gas processing plant in McKenzie County, North Dakota, that will increase our total natural gas processing capacity in the Williston Basin to more than 1.2 billion cubic feet per day (Bcf/d).

E **Elk Creek Pipeline | Expected Completion: Year-end 2019 | Approximate Cost: $1.4 billion**
A 900-mile pipeline with capacity to transport up to 240,000 bpd of raw NGLs from near our Riverview terminal in eastern Montana to Bushton, Kansas.

F **Arbuckle II Pipeline | Expected Completion: First Quarter 2020 | Approximate Cost: $1.36 billion**
A 530-mile pipeline with capacity to transport up to 400,000 bpd of raw NGLs originating across our NGL supply basins and extensive NGL gathering system to Mont Belvieu, Texas.

G **MB-4 NGL Fractionator and Storage | Expected Completion: First Quarter 2020 | Approximate Cost: $575 million**
A 125,000 bpd NGL fractionator that will increase our Mont Belvieu fractionation capacity to 965,000 bpd.

*Represents ONEOK's 80 percent ownership interest

CONNECTIONS ARE ESSENTIAL TO OUR BUSINESS

As a midstream service provider, we gather natural gas from high-producing basins and transport it to our network of processing plants for treatment and processing. These services are primarily fee-based and necessary to bring natural gas to market.

Our natural gas gathering and processing segment operates more than 19,000 miles of gathering pipelines in the heart of the Williston Basin, Powder River Basin and the STACK and SCOOP plays in the Mid-Continent, where producers continue to see favorable returns.

To help meet the growing need for natural gas processing capacity in areas where we operate, we announced the expansion of our Canadian Valley plant in Oklahoma. The project is expected to add 200 MMcf/d of natural gas processing capacity in the STACK play and increase our total natural gas processing capacity in the Mid-Continent to 1.2 Bcf/d by the end of 2018.

We also announced plans to construct the Demicks Lake plant in North Dakota, where we have 3 million acres of dedication in the Williston Basin. The project is expected to add 200 MMcf/d of natural gas processing capacity to our system and increase our total processing capacity in the region to more than 1.2 Bcf/d.

Combined, we expect the Canadian Valley and Demicks Lake projects to bring our systemwide natural gas processing capacity to more than 2.4 Bcf/d by the end of 2019. These new plants are supported by substantial acreage dedications, including 1 million acres in the core of the Williston Basin and 300,000 acres in the STACK and SCOOP plays.

In 2017, we secured up to 200 MMcf/d of processing capacity in the heart of the STACK play via a long-term, third-party processing services agreement.

Once natural gas is processed, we transport it by pipeline to end-use markets that serve a variety of industries, including electric and natural gas utilities. In addition, the extracted NGLs are added to our NGL system.

Our natural gas pipelines segment operates more than 6,000 miles of transportation pipeline with peak capacity of 7.0 Bcf/d and more than 50 Bcf/d of natural gas storage.

Our natural gas transmission and storage assets extend south from the Canadian border, through the Williston Basin, Mid-Continent and prolific Permian Basin, to the Mexican border.

The natural gas pipelines segment is a stable source of fee-based earnings, which we are well-positioned to grow via export capabilities, particularly in Mexico, where we have key relationships from our joint-venture Roadrunner Gas Transmission Pipeline and ONEOK WesTex Transmission system.

Canadian Valley natural gas processing plant in Canadian County, Oklahoma

PARTNERING WITH LANDOWNERS

Dan Hanson • Landowner • Niobrara County, Wyoming

"I'm a third-generation cattle rancher. My grandparents worked for the big cattle outfits before deciding to homestead and start their own ranch in 1905. My wife Donna and I have worked and raised a family on this land since 1981.

I've worked with ONEOK on two projects – the Bakken NGL Pipeline and the Douglas Lateral (part of the Bakken NGL Pipeline system) – in Wyoming. I've got three other pipelines running through my property, but ONEOK was my first good experience with a pipeline company. They brought in people from the company to listen to me and address my concerns. I really appreciated that.

We've had bad experiences with other companies who just sent their people with final offers or threats of condemnation. ONEOK has been really good to deal with, sending out people that could make decisions with the negotiating team, thus we have been able to build a good relationship with them.

On the Bakken project, I helped organize landowners in my area. We negotiated easements to include some terms related to reclamation and liability that were beneficial to me and other ranchers in the area. Reclamation is important to us because grass is our product. Cattle are merely machines to harvest it. We're selling grass for human consumption through beef, so restoring the land back to health after the pipeline has been laid is really important to us.

On the Douglas Lateral, we had some trouble getting plants to grow after the land had been restored. ONEOK has seeded three times to make it right. I have complete confidence that ONEOK will help restore the native plants."

2017 FINANCIAL **PERFORMANCE** AND 2018 **GUIDANCE**

ONEOK's 2017 financial performance benefited from volume growth across our operating footprint, resulting in a more than 7 percent increase in operating income and adjusted EBITDA compared with 2016.

ONEOK increased dividends paid to shareholders by 11 percent compared with 2016 while maintaining substantial dividend coverage and proactively managing our balance sheet. We ended 2017 with a GAAP debt-to-EBITDA ratio of 4.6 times and on a pro forma basis, we met our target of 4 times or less following our January 2018 equity offering. These metrics are important to ONEOK and key to maintaining our investment-grade credit ratings, which provide a significant competitive advantage for us.

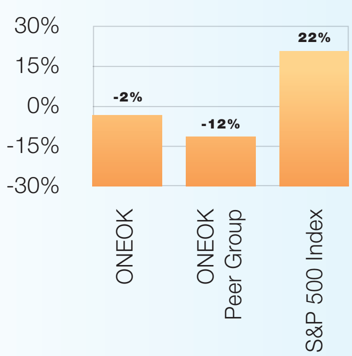
ONEOK's average share price in 2017 increased 30 percent compared with 2016 and increased nearly 40 percent compared with our average share price in 2015. The value we are creating through disciplined financial management and investments in attractive-return, fee-based capital-growth projects is being recognized by the investment community.

In 2018, we expect even stronger performance, leading to net income of more than $1 billion and adjusted EBITDA of more than $2.3 billion, representing a more than 15 percent increase compared with 2017.

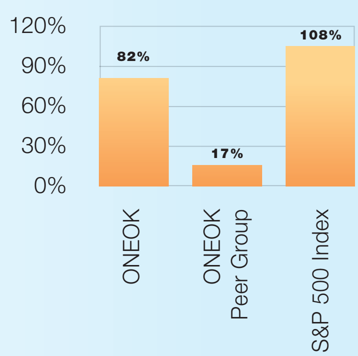
TOTAL SHAREHOLDER RETURN*

ONEOK's 10-, five- and one-year total shareholder returns consistently have outperformed those of our peer group. Long-term shareholders have been rewarded with returns far exceeding those of the S&P 500 Index.

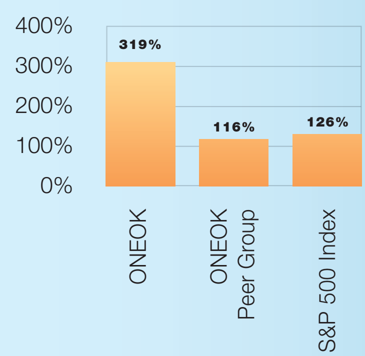
1-YEAR



5-YEAR



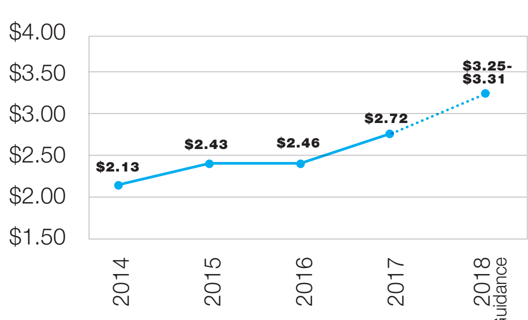
10-YEAR



As of Dec. 31, 2017
*Total return represents share-price appreciation and the reinvestment of dividends.

DIVIDEND GROWTH

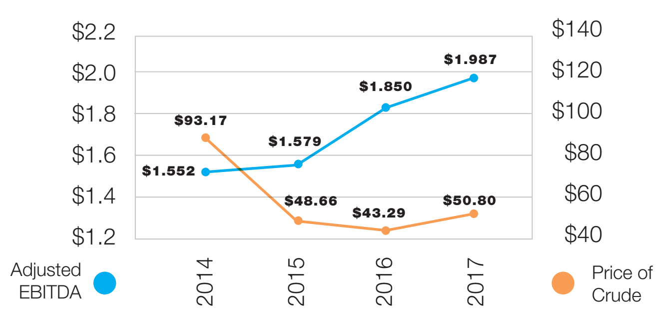
Approximately 85 to 95 percent of ONEOK's 2018 dividend payments to investors are expected to be a return of capital.



ONEOK annual dividends paid per share

ADJUSTED EBITDA (IN BILLIONS)

Compared with average price of crude per barrel*



*Source: U.S. Energy Information Administration

CORPORATE INFORMATION

ONEOK Annual Meeting
The 2018 annual meeting of shareholders will be held Wednesday, May 23, 2018, at 9 a.m. Central Daylight Time at ONEOK Plaza, 100 West Fifth Street, Tulsa, OK.

Auditors
PricewaterhouseCoopers LLP
Two Warren Place
6120 South Yale Avenue, Suite 1850
Tulsa, OK 74136

Direct Stock Purchase and Dividend Reinvestment Plan
ONEOK's Direct Stock Purchase and Dividend Reinvestment Plan provides investors the opportunity to purchase shares of common stock without payment of any brokerage fees or service charges and to reinvest dividends automatically.

Transfer Agent, Registrar and Dividend Disbursing Agent
EQ Shareowner Services
P.O. Box 64854
St. Paul, MN 55164-0854
866-235-0232
www.shareowneronline.com

Credit Ratings	**OKE**
S&P Global Ratings	BBB (stable)
Moody's Investors Service	Baa3 (stable)

Investor Relations
Andrew Ziola, vice president – investor relations and corporate affairs, by phone at 918-588-7683 or by email at aziola@oneok.com.

Megan Patterson, manager – investor relations, by phone at 918-561-5325 or by email at mpatterson@oneok.com.

Corporate Website
www.oneok.com

Ruby, field engineer, at the Grasslands natural gas processing plant in McKenzie County, North Dakota

NON-GAAP (GENERALLY ACCEPTED ACCOUNTING PRINCIPLES) FINANCIAL MEASURES

ONEOK has disclosed in this annual report adjusted EBITDA and distributable cash flow, which are non-GAAP financial metrics, used to measure the company's financial performance and are defined as follows:

- Adjusted EBITDA is defined as net income from continuing operations adjusted for interest expense, depreciation and amortization, noncash impairment charges, income taxes, noncash compensation expense, allowance for equity funds used during construction (equity AFUDC) and other noncash items; and
- Distributable cash flow is defined as adjusted EBITDA, computed as described above, less interest expense, maintenance capital expenditures and equity earnings from investments, excluding noncash impairment charges, adjusted for cash distributions received from unconsolidated affiliates and certain other items.

These non-GAAP financial measures described above are useful to investors because they, and many similar measures, are used by many companies in the industry as a measure of financial performance and are commonly employed by financial analysts and others to evaluate our financial performance and to compare our financial performance with the performance of other companies within our industry. Adjusted EBITDA and ONEOK's distributable cash flow should not be considered in isolation or as a substitute for net income or any other measure of financial performance presented in accordance with GAAP.

These non-GAAP financial measures exclude some, but not all, items that affect net income. Additionally, these calculations may not be comparable with similarly titled measures of other companies. Reconciliations of net income to adjusted EBITDA and distributable cash flow are included in the tables.

FORWARD-LOOKING STATEMENTS

Forward-looking statements are based on current expectations, estimates and assumptions that involve a number of risks and uncertainties, many of which are beyond our control, and are not guarantees of future results. Accordingly, there are or will be important factors that could cause actual results to differ materially from those indicated in such statements and, therefore, you should not place undue reliance on any such statements and caution must be exercised in relying on forward-looking statements. These risks and uncertainties include, without limitation, the following:

- the effects of weather and other natural phenomena, including climate change, on our operations, demand for our services and energy prices;
- competition from other United States and foreign energy suppliers and transporters, as well as alternative forms of energy, including, but not limited to, solar power, wind power, geothermal energy and biofuels such as ethanol and biodiesel;
- the capital intensive nature of our businesses;
- the profitability of assets or businesses acquired or constructed by us;
- our ability to make cost-saving changes in operations;
- risks of marketing, trading and hedging activities, including the risks of changes in energy prices or the financial condition of our counterparties;
- the uncertainty of estimates, including accruals and costs of environmental remediation;
- the timing and extent of changes in energy commodity prices;
- the effects of changes in governmental policies and regulatory actions, including changes with respect to income and other taxes, pipeline safety, environmental compliance, climate change initiatives and authorized rates of recovery of natural gas and natural gas transportation costs;
- the impact on drilling and production by factors beyond our control, including the demand for natural gas and crude oil; producers' desire and ability to obtain necessary permits; reserve performance; and capacity constraints on the pipelines that transport crude oil, natural gas and NGLs from producing areas and our facilities;
- difficulties or delays experienced by trucks, railroads or pipelines in delivering products to or from our terminals or pipelines;
- changes in demand for the use of natural gas, NGLs and crude oil because of market conditions caused by concerns about climate change;
- the impact of unforeseen changes in interest rates, debt and equity markets, inflation rates, economic recession and other external factors over which we have no control, including the effect on pension and postretirement expense and funding resulting from changes in equity and bond market returns;
- our indebtedness and guarantee obligations could make us vulnerable to general adverse economic and industry conditions, limit our ability to borrow additional funds and/or place us at competitive disadvantages compared with our competitors that have less debt, or have other adverse consequences;
- actions by rating agencies concerning our credit ratings;
- the results of administrative proceedings and litigation, regulatory actions, rule changes and receipt of expected clearances involving any local, state or federal regulatory body, including the Federal Energy Regulatory Commission (FERC), the National Transportation Safety Board, the Pipeline and Hazardous Materials Safety Administration (PHMSA), the U.S. Environmental Protection Agency (EPA) and the U.S. Commodity Futures Trading Commission (CFTC);
- our ability to access capital at competitive rates or on terms acceptable to us;
- risks associated with adequate supply to our gathering, processing, fractionation and pipeline facilities, including production declines that outpace new drilling or extended periods of ethane rejection;
- the risk that material weaknesses or significant deficiencies in our internal controls over financial reporting could emerge or that minor problems could become significant;
- the impact and outcome of pending and future litigation;
- the ability to market pipeline capacity on favorable terms, including the effects of:
    - future demand for and prices of natural gas, NGLs and crude oil;
    - competitive conditions in the overall energy market;
    - availability of supplies of Canadian and United States natural gas and crude oil; and
    - availability of additional storage capacity;
- performance of contractual obligations by our customers, service providers, contractors and shippers;
- the timely receipt of approval by applicable governmental entities for construction and operation of our pipeline and other projects and required regulatory clearances;
- our ability to acquire all necessary permits, consents or other approvals in a timely manner, to promptly obtain all necessary materials and supplies required for construction, and to construct gathering, processing, storage, fractionation and transportation facilities without labor or contractor problems;
- the mechanical integrity of facilities operated;
- demand for our services in the proximity of our facilities;
- our ability to control operating costs;
- acts of nature, sabotage, terrorism or other similar acts that cause damage to our facilities or our suppliers' or shippers' facilities;
- economic climate and growth in the geographic areas in which we do business;
- the risk of a prolonged slowdown in growth or decline in the United States or international economies, including liquidity risks in United States or foreign credit markets;
- the impact of recently issued and future accounting updates and other changes in accounting policies;
- the possibility of future terrorist attacks or the possibility or occurrence of an outbreak of, or changes in, hostilities or changes in the political conditions throughout the world;
- the risk of increased costs for insurance premiums, security or other items as a consequence of terrorist attacks;
- risks associated with pending or possible acquisitions and dispositions, including our ability to finance or integrate any such acquisitions and any regulatory delay or conditions imposed by regulatory bodies in connection with any such acquisitions and dispositions;
- the impact of uncontracted capacity in our assets being greater or less than expected;
- the ability to recover operating costs and amounts equivalent to income taxes, costs of property, plant and equipment and regulatory assets in our state and FERC-regulated rates;
- the composition and quality of the natural gas and NGLs we gather and process in our plants and transport on our pipelines;
- the efficiency of our plants in processing natural gas and extracting and fractionating NGLs;
- the impact of potential impairment charges;
- the risk inherent in the use of information systems in our respective businesses, implementation of new software and hardware, and the impact on the timeliness of information for financial reporting;
- our ability to control construction costs and completion schedules of our pipelines and other projects; and
- the risk factors listed in the report ONEOK has filed and may file with the Securities and Exchange Commission (the "SEC"), which are incorporated by reference.

These reports also are available from the sources described below. Forward-looking statements are based on the estimates and opinions of management at the time the statements are made. ONEOK undertakes no obligation to publicly update any forward-looking statement, whether as a result of new information, future events or changes in circumstances, expectations or otherwise.

The foregoing review of important factors should not be construed as exhaustive and should be read in conjunction with the other cautionary statements that are included herein and elsewhere, including the Risk Factors included in the most recent reports on Form 10-K and Form 10-Q and other documents of ONEOK on file with the SEC. ONEOK's SEC filings are available publicly on the SEC's website at www.sec.gov.

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

FORM 10-K

X ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2017.
OR
__ 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 001-13643

ONEOK, Inc.

(Exact name of registrant as specified in its charter)

Oklahoma	**73-1520922**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
100 West Fifth Street, Tulsa, OK	**74103**
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code **(918) 588-7000**

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

Common stock, par value of $0.01	**New York Stock Exchange**
(Title of each class)	(Name of each exchange on which registered)

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__.

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 __ 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 __

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes X No __

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Registration S-K (§ 229.405 of this chapter) 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. __

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, 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 __ Non-accelerated filer __ Smaller reporting company __
Emerging growth company___

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.__

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes__ No X.

Aggregate market value of registrant's common stock held by non-affiliates based on the closing trade price on June 30, 2017, was $19.5 billion.

On February 22, 2018, the Company had 410,634,227 shares of common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE:

Portions of the definitive proxy statement to be delivered to shareholders in connection with the Annual Meeting of Shareholders to be held May 23, 2018, are incorporated by reference in Part III.

ONEOK, Inc.
2017 ANNUAL REPORT

As used in this Annual Report, references to “we,” “our,” or “us” refer to ONEOK, Inc., an Oklahoma corporation, and its predecessors and subsidiaries unless the context indicates otherwise.

GLOSSARY

The abbreviations, acronyms and industry terminology used in this Annual Report are defined as follows:

$2.5 Billion Credit Agreement	ONEOK's $2.5 billion revolving credit agreement, effective June 30, 2017
AFUDC	Allowance for funds used during construction
Annual Report	Annual Report on Form 10-K for the year ended December 31, 2017
ASU	Accounting Standards Update
Bbl	Barrels, 1 barrel is equivalent to 42 United States gallons
BBtu/d	Billion British thermal units per day
Bcf	Billion cubic feet
Bcf/d	Billion cubic feet per day
CFTC	U.S. Commodity Futures Trading Commission
Clean Air Act	Federal Clean Air Act, as amended
Clean Water Act	Federal Water Pollution Control Act Amendments of 1972, as amended
DOT	United States Department of Transportation
EBITDA	Earnings before interest expense, income taxes, depreciation and amortization
EPA	United States Environmental Protection Agency
Exchange Act	Securities Exchange Act of 1934, as amended
FERC	Federal Energy Regulatory Commission
Foundation	ONEOK Foundation, Inc.
GAAP	Accounting principles generally accepted in the United States of America
GHG	Greenhouse gas
Intermediate Partnership	ONEOK Partners Intermediate Limited Partnership, a wholly owned subsidiary of ONEOK Partners, L.P.
IRS	Internal Revenue Service
KCC	Kansas Corporation Commission
LIBOR	London Interbank Offered Rate
MBbl	Thousand barrels
MBbl/d	Thousand barrels per day
MDth/d	Thousand dekatherms per day
Merger Transaction	The transaction, effective June 30, 2017, in which ONEOK acquired all of ONEOK Partners' outstanding common units not already directly or indirectly owned by ONEOK
MMBbl	Million barrels
MMBtu	Million British thermal units
MMcf/d	Million cubic feet per day
Moody's	Moody's Investors Service, Inc.
Natural Gas Act	Natural Gas Act of 1938, as amended
Natural Gas Policy Act	Natural Gas Policy Act of 1978, as amended
NGL(s)	Natural gas liquid(s)
NGL products	Marketable natural gas liquid purity products, such as ethane, ethane/propane mix, propane, iso-butane, normal butane and natural gasoline
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
OCC	Oklahoma Corporation Commission
ONE Gas	ONE Gas, Inc.
ONEOK	ONEOK, Inc.
ONEOK Credit Agreement	ONEOK's $300 million amended and restated revolving credit agreement, which terminated June 30, 2017
ONEOK Partners	ONEOK Partners, L.P.
ONEOK Partners Credit Agreement	ONEOK Partners' $2.4 billion amended and restated revolving credit agreement, which terminated June 30, 2017
ONEOK Partners GP	ONEOK Partners GP, L.L.C., a wholly owned subsidiary of ONEOK and the sole general partner of ONEOK Partners

OPIS	Oil Price Information Service
OSHA	Occupational Safety and Health Administration
PHMSA	United States Department of Transportation Pipeline and Hazardous Materials Safety Administration
POP	Percent of Proceeds
Quarterly Report(s)	Quarterly Report(s) on Form 10-Q
Roadrunner	Roadrunner Gas Transmission, LLC, a 50 percent-owned joint venture
RRC	Railroad Commission of Texas
S&P	S&P Global Ratings
SCOOP	South Central Oklahoma Oil Province, an area in the Anadarko Basin in Oklahoma
SEC	Securities and Exchange Commission
Securities Act	Securities Act of 1933, as amended
Series E Preferred Stock	Series E Non-Voting, Perpetual Preferred Stock, par value $0.01 per share
STACK	Sooner Trend Anadarko Canadian Kingfisher, an area in the Anadarko Basin in Oklahoma
Tax Cuts and Jobs Act	H.R. 1, the tax reform bill, signed into law on December 22, 2017
Term Loan Agreement	ONEOK Partners' senior unsecured three-year $1.0 billion term loan agreement dated January 8, 2016, as amended
Topic 606	Accounting Standards Update 2014-09, "Revenue from Contracts with Customers"
West Texas LPG	West Texas LPG Pipeline Limited Partnership and Mesquite Pipeline
WTI	West Texas Intermediate
WTLPG	West Texas LPG Pipeline Limited Partnership, an 80 percent-owned joint venture
XBRL	eXtensible Business Reporting Language

The statements in this Annual Report that are not historical information, including statements concerning plans and objectives of management for future operations, economic performance or related assumptions, are forward-looking statements. Forward-looking statements may include words such as "anticipate," "estimate," "expect," "project," "intend," "plan," "believe," "should," "goal," "forecast," "guidance," "could," "may," "continue," "might," "potential," "scheduled" and other words and terms of similar meaning. Although we believe that our expectations regarding future events are based on reasonable assumptions, we can give no assurance that such expectations or assumptions will be achieved. Important factors that could cause actual results to differ materially from those in the forward-looking statements are described under Part I, Item 1A, Risk Factors, and Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations and "Forward-Looking Statements," in this Annual Report.

PART I

ITEM 1. BUSINESS

GENERAL

We are a corporation incorporated under the laws of the state of Oklahoma, and our common stock is listed on the NYSE under the trading symbol “OKE.” We are a leading midstream service provider and own one of the nation’s premier natural gas liquids systems, connecting NGL supply in the Mid-Continent, Permian and Rocky Mountain regions with key market centers and an extensive network of natural gas gathering, processing, storage and transportation assets. We apply our core capabilities of gathering, processing, fractionating, transporting, storing and marketing natural gas and NGLs through vertical integration across the midstream value chain to provide our customers with premium services while generating consistent and sustainable earnings growth.

EXECUTIVE SUMMARY

Merger Transaction - On June 30, 2017, we completed the acquisition of all of the outstanding common units of ONEOK Partners that we did not already own at a fixed exchange ratio of 0.985 of a share of our common stock for each ONEOK Partners common unit. We issued 168.9 million shares of our common stock to third-party common unitholders of ONEOK Partners in exchange for all of the 171.5 million outstanding common units of ONEOK Partners that we previously did not own. As a result of the completion of the Merger Transaction, common units of ONEOK Partners are no longer publicly traded. The change in our ownership interest resulting from the Merger Transaction was accounted for as an equity transaction, and no gain or loss was recognized in our Consolidated Statement of Income.

Business Update and Market Conditions - We operate primarily fee-based businesses in each of our three reportable segments. Our consolidated earnings were approximately 90 percent fee-based in 2017, and we expect the same for 2018. In 2017, our Natural Gas Gathering and Processing segment’s fee revenues averaged 86 cents per MMBtu, compared with an average of 76 cents and 44 cents per MMBtu in 2016 and 2015, respectively, due to our contract restructuring efforts to mitigate commodity price risk and increasing volumes on those contracts with higher contracted fees. Volumes gathered and processed increased across our asset footprint in our Natural Gas Gathering and Processing segment in 2017, compared with 2016, as producers experienced improved drilling economics, continued improvements in production due to enhanced completion techniques and more efficient drilling rigs. We connected six third-party natural gas processing plants in our Natural Gas Liquids segment in 2017, which, along with increased supply and ethane recovery, contributed to higher gathered NGL volumes in 2017, compared with 2016. We expect additional NGL volume growth as these plants continue to increase production and recently announced plant connections come online. Our fee-based transportation services in our Natural Gas Pipelines segment increased in 2017, compared with 2016, due primarily to higher firm transportation capacity contracted from our WesTex pipeline expansion.

We continue to expect demand for our midstream services and infrastructure development to be primarily driven by producers who need to connect production with end-use markets where current infrastructure is insufficient. We are responding to this demand by constructing assets, such as our recently announced Elk Creek pipeline, Arbuckle II pipeline, MB-4 fractionator, Demicks Lake natural gas processing plant and other projects discussed below, to meet the needs of producers. We also expect additional demand for our services to support increased demand for NGL products from the petrochemical industry and NGL exporters, and increased demand for natural gas from exports and power plants, some of which were previously fueled by coal.

We are connected to supply in growing basins and have significant basin diversification across our asset footprint, including the Williston, Denver-Julesburg (DJ), Permian and Powder River Basins and the STACK and SCOOP areas. In addition, we are connected to major market centers for natural gas and NGL products. While our Natural Gas Gathering and Processing and Natural Gas Liquids segments generate primarily fee-based earnings, those segments’ results of operations are exposed to volumetric risk. Our exposure to volumetric risk can result from declining well productivity, reduced drilling activity, severe weather disruptions, operational outages and ethane rejection.

Rocky Mountain Region - We expect each of our business segments to benefit from increased production in this region, which includes the Williston, DJ and Powder River Basins, where there was an increase in producer activity in 2017, which we expect to continue throughout 2018. In our Natural Gas Gathering and Processing segment, our completed growth projects have increased our gathering and processing capacity to more than 1.0 Bcf/d and allow us to capture additional natural gas. We have available natural gas processing capacity in the Williston Basin of approximately 125 MMcf/d and approximately one million acres dedicated to us in the core of this basin. With continued volume growth expected due to improved drilling economics and producer efficiencies, we announced plans to construct the 200 MMcf/d Demicks Lake natural gas processing plant in the core of the Williston Basin. The Demicks Lake plant is expected to provide services necessary to help producers meet natural gas capture targets, while adding incremental NGLs to our NGL gathering system and supplying additional natural gas to our 50 percent owned Northern Border Pipeline. This project is supported by long-term primarily fee-based contracts and acreage dedications. In our Natural Gas Liquids segment, we are the largest NGL takeaway provider in the Williston Basin with five connections to third-party natural gas processing plants in addition to our own. We connected one new third-party natural gas processing plant in the region in the first quarter 2017. The volume growth in this region has resulted in our existing Bakken NGL Pipeline and the Overland Pass Pipeline, of which we own 50 percent, operating at full capacity. In January 2018, we announced plans to construct the Elk Creek pipeline, which includes construction of an approximately 900-mile pipeline and related infrastructure to transport NGLs from the Rocky Mountain region to our existing Mid-Continent NGL facilities. This project, which is anchored by long-term contracts supported primarily by minimum volume commitments, will have an initial capacity of 240 MBbl/d, with the ability to be expanded to 400 MBbl/d with additional pump facilities. The Elk Creek pipeline project is expected to strengthen our position in the high-production areas of the Williston, Powder River and DJ Basins. In our Natural Gas Pipelines segment, our 50 percent-owned Northern Border Pipeline is well-positioned to transport natural gas from processing plants in the Williston Basin, including the recently announced Demicks Lake plant, to end-use markets and is substantially contracted through the fourth quarter 2020.

STACK and SCOOP - We expect each of our business segments to benefit from increased production in the Mid-Continent region from the highly productive STACK and SCOOP areas where there was an increase in producer activity in late 2016 and in 2017, which we expect to continue throughout 2018.

As producers continue to develop the STACK and SCOOP areas, we expect natural gas and NGL volumes on our systems to increase throughout 2018, compared with volumes for the same periods in 2016 and 2017, and expect increased demand for our services from producers that need incremental takeaway capacity for natural gas and NGLs out of the region. We anticipate NGL volume growth in the Mid-Continent region will also be driven by expected increases in ethane recovery as new world-scale ethylene production projects, petrochemical plant expansions and export facilities are completed.

In our Natural Gas Gathering and Processing segment, we have more than 300,000 acres dedicated to us in the STACK and SCOOP areas. In 2017, we announced plans to expand our Canadian Valley natural gas processing facility to 400 MMcf/d from 200 MMcf/d, which is expected to be completed by the end of 2018. The project is supported by long-term primarily fee-based contracts, minimum volume commitments and acreage dedications. In December 2017, we also completed a connection of our natural gas gathering systems in the STACK area to an existing third-party processing facility, accessing up to 200 MMcf/d of processing capacity by constructing a 30-mile natural gas gathering pipeline and related infrastructure. In our Natural Gas Liquids segment, we are the largest NGL takeaway provider in the STACK and SCOOP areas. We have more than 110 connections to third-party natural gas processing plants in the Mid-Continent region, and in 2017, we connected three third-party natural gas processing plants. We announced plans to expand our natural gas liquids gathering system in the Mid-Continent region and our existing Sterling III pipeline, which are supported by long-term fee-based contracts and expected to be completed by the end of 2018. In February 2018, we announced plans to construct the Arbuckle II pipeline, which includes construction of an approximately 530-mile pipeline and related infrastructure to transport NGLs originating across our supply basins to Mont Belvieu, Texas. This pipeline project will have an initial capacity of 400 MBbl/d, with the ability to be expanded with additional pump facilities. This project is supported by long-term fee-based contracts. In our Natural Gas Pipelines segment, we are connected to more than 30 natural gas processing plants in Oklahoma, which have a total processing capacity of approximately 1.8 Bcf/d, and are expanding our ONEOK Gas Transportation pipeline by 100 MMcf/d to provide increased westbound transportation services from the STACK and SCOOP areas.

Permian Basin - We expect our Natural Gas Liquids and Natural Gas Pipelines business segments to benefit from increased production in the Permian Basin from the highly productive Delaware and Midland Basins, where there was an increase in producer drilling activity in late 2016 and in 2017, which we expect to continue throughout 2018.

In our Natural Gas Liquids segment, we are well-positioned in the Permian Basin with approximately 40 connections to third-party natural gas processing plants through our WTLPG joint venture, where we connected two third-party natural gas processing plants in 2017. In 2017, we announced that our WTLPG joint venture, in which we own an 80 percent interest, plans to extend its pipeline system into the core of the Delaware Basin, which includes construction of an approximately 120-mile pipeline lateral and related infrastructure to provide an initial incremental capacity of 110 MBbl/d. This project, which we expect to be completed in the third quarter 2018, is supported by long-term dedicated NGL production from two planned third-party natural gas processing plants and positions the West Texas LPG pipeline for significant future NGL volume growth. In our Natural Gas Pipelines segment, we believe that Roadrunner and our WesTex pipeline are well-positioned to serve growth in the Permian Basin. We are connected to more than 25 natural gas processing plants serving the Permian Basin, which have a total processing capacity of approximately 1.9 Bcf/d. The Roadrunner pipeline transports natural gas from the Permian Basin to the Mexican border near El Paso, Texas, and is fully subscribed with 25-year firm demand charge, fee-based agreements.

The Roadrunner pipeline connects with our existing natural gas pipeline and storage infrastructure in Texas and, together with our completed WesTex intrastate natural gas pipeline expansion project, creates future opportunities for us to deliver natural gas supply to Mexico.

Gulf Coast - Demand for NGLs is expected to grow at the NGL market center in Mont Belvieu, Texas, as new world-scale ethylene production projects, petrochemical plant expansions and export facilities are completed. We expect increased NGL supply across our assets and construction of our Sterling III and WTLPG pipeline expansions, Elk Creek pipeline and Arbuckle II pipeline projects to result in higher NGL deliveries to this NGL market center. We have significant NGL fractionation and storage assets in this area, and additional capacity is needed to accommodate expected volume growth. In February 2018, we announced plans to construct the 125 MBbl/d MB-4 fractionator and related infrastructure in Mont Belvieu, Texas, which includes additional NGL storage capacity. This project is supported by long-term fee-based contracts and is fully contracted. Following the completion of MB-4, we expect our total NGL fractionation capacity to be 965 MBbl/d.

See Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, for more information on our growth projects, results of operations, liquidity and capital resources.

BUSINESS STRATEGY

Our primary business strategy is to maintain prudent financial strength and flexibility while growing our fee-based earnings and dividends per share with a focus on safe, reliable, environmentally responsible, legally compliant and sustainable operations for our customers, employees, contractors and the public through the following:

- <u>Operate in a safe, reliable, environmentally responsible and sustainable manner</u> - environmental, safety and health issues continue to be a primary focus for us, and our emphasis on personal and process safety has produced improvements in the key indicators we track. We also continue to look for ways to reduce our environmental impact by conserving resources and utilizing more efficient technologies;
- <u>Maintain prudent financial strength and flexibility while growing our fee-based earnings, dividends per share and cash flows from operations in excess of dividends paid</u> - we operate primarily fee-based businesses in each of our three reportable segments. We continue to invest in organic growth projects to expand our existing asset footprint and provide a broad range of services to crude oil and natural gas producers and end-use markets. In February 2018, we paid a quarterly dividend of $0.77 per share ($3.08 per share on an annualized basis), an increase of 25 percent compared with the same quarter in the prior year. Our dividend increase and expected future dividend growth is due in part to the increase in cash flows resulting from the Merger Transaction and our growth projects. Since June 2017, we have announced organic growth projects totaling approximately $4.2 billion supported by a combination of long-term primarily fee-based contracts, minimum volume commitments and acreage dedications;
- <u>Manage our balance sheet and maintain investment-grade credit ratings</u> - we seek to maintain investment-grade credit ratings. In January 2018, we completed an underwritten public offering of our common stock generating net proceeds of $1.2 billion, which we expect to satisfy our equity financing needs through 2018 and well into 2019. Following the equity offering, we had $2.5 billion of borrowing capacity available and expect to fund our growth projects through cash from operations and a combination of short- and long-term debt; and
- <u>Attract, select, develop and retain a diverse group of employees to support strategy execution</u> - we continue to execute on our recruiting strategy that targets professional and field personnel in our operating areas. We also continue to focus on employee development efforts with our current employees and monitor our benefits and compensation package to remain competitive.

NARRATIVE DESCRIPTION OF BUSINESS

We report operations in the following business segments:

- Natural Gas Gathering and Processing;
- Natural Gas Liquids; and
- Natural Gas Pipelines.

<u>Natural Gas Gathering and Processing</u>

Overview - Our Natural Gas Gathering and Processing segment provides midstream services to contracted producers in North Dakota, Montana, Wyoming, Kansas and Oklahoma. Raw natural gas is typically gathered at the wellhead, compressed and transported through pipelines to our processing facilities. In order for the natural gas to be accepted by the downstream market, it must have contaminants, such as water, nitrogen and carbon dioxide, removed and NGLs separated for further processing. Processed natural gas, usually referred to as residue natural gas, is then recompressed and delivered to natural gas pipelines, storage facilities and end users. The separated NGLs are sold and delivered through natural gas liquids pipelines to fractionation facilities for further separation.

Rocky Mountain region - The Williston Basin, which is located in portions of North Dakota and Montana, includes the oil-producing, NGL-rich Bakken Shale and Three Forks formations, is an active drilling region. Our completed growth projects in the Williston Basin since 2016 have increased our gathering and processing capacity to more than 1.0 Bcf/d and allow us to capture increased natural gas production from new wells and previously flared natural gas production.

The Powder River Basin is primarily located in Wyoming, which includes the NGL-rich Niobrara Shale and Frontier, Turner and Sussex formations where we provide gathering and processing services to customers in the southeast portion of Wyoming.

Mid-Continent region - The Mid-Continent region is an active drilling region and includes the oil-producing, NGL-rich STACK and SCOOP areas and the Cana-Woodford Shale, Woodford Shale, Springer Shale, Meramec, Granite Wash and Mississippian Lime formations of Oklahoma and Kansas; and the Hugoton and Central Kansas Uplift Basins of Kansas.

Revenues - Revenues for this segment are derived primarily from commodity sales and the following types of services contracts:

- POP with fee-based components - This type of contract includes contractual fees for gathering, treating, compressing and processing the producer's natural gas. We also generally purchase the producer's raw natural gas, which we process into residue natural gas and NGLs, then we sell these commodities and associated condensate to downstream customers. We remit sales proceeds to the producer according to the contractual terms and retain our portion. This type of contract represented approximately 96 percent and 94 percent of supply volumes in this segment for 2017 and 2016, respectively. There are a variety of factors that directly affect our POP with fee revenues, including:
  - the price of natural gas, crude oil and NGLs;
  - the composition of the natural gas and NGLs produced;
  - the fees we charge for our services; and
  - the volume produced.

  Over time as our contracts are renewed or restructured, we have generally increased the fee components. In some POP with fee contracts, instead of remitting cash payments to the producer, we deliver an agreed-upon percentage of residue gas and/or NGLs to the producer (take-in-kind) and sell the volumes we retain to third parties. Additionally, under certain POP with fee contracts our contractual fees may increase or decrease if production volumes, delivery pressures or commodity prices change relative to specified thresholds.
- Fee-only - Under this type of contract, we are paid a fee for the services we provide, based on volumes gathered, processed, treated and/or compressed. Our fee-only contracts represented approximately 4 percent and 6 percent of supply volumes in this segment for 2017 and 2016, respectively.

We contract to deliver residue natural gas, condensate and/or unfractionated NGLs to downstream customers at a specified delivery point. Our sales of NGLs are typically to our affiliate in the Natural Gas Liquids segment.

Upon adoption of Topic 606 in January 2018, the contractual fees we charge producers on the majority of our POP with fee contracts will be recorded as a reduction of the purchase price in cost of sales and fuel. In 2017 and prior periods, we recorded these fees as services revenue. The contractual fees on POP with fee contracts that include producer take-in-kind rights will continue to be recorded as services revenue, as we do not control the raw natural gas stream while we are providing midstream services. We do not expect adoption of the standard to be material to this segment's operating income.

Property - Our Natural Gas Gathering and Processing segment owns the following assets:

- approximately 11,400 miles and 7,700 miles of natural gas gathering pipelines in the Mid-Continent and Rocky Mountain regions, respectively;
- nine natural gas processing plants with approximately 800 MMcf/d of processing capacity in the Mid-Continent region, and 11 natural gas processing plants with approximately 1,050 MMcf/d of processing capacity in the Rocky Mountain region; and
- approximately 15 MBbl/d of natural gas liquids fractionation capacity at various natural gas processing plants in the Rocky Mountain region.

In addition, we have access to up to 200 MMcf/d of processing capacity in the Mid-Continent region through a long-term processing services agreement with an unaffiliated third party.

Utilization - The utilization rates for our natural gas processing plants were approximately 79 percent and 76 percent for 2017 and 2016, respectively. We calculate utilization rates using a weighted-average approach, adjusting for the dates that assets were placed in service.

Unconsolidated Affiliates - Our Natural Gas Gathering and Processing segment includes the following unconsolidated affiliates:

- 49 percent ownership in Bighorn Gas Gathering, which gathers coal-bed methane produced in the Powder River Basin;
- 37 percent ownership in Fort Union Gas Gathering, which gathers coal-bed methane produced in the Powder River Basin and delivers it to the interstate pipeline system;
- 35 percent ownership interest in Lost Creek Gathering Company, which gathers natural gas produced from conventional dry natural gas wells in the Wind River Basin of central Wyoming and delivers it to the interstate pipeline system; and
- 10 percent ownership interest in Venice Energy Services Co., a natural gas processing facility near Venice, Louisiana.

See Note N of the Notes to Consolidated Financial Statements in this Annual Report for additional discussion of our unconsolidated affiliates.

Market Conditions and Seasonality - Supply - Our natural gas gathered and processed volumes increased in 2017, compared with 2016, due primarily to the following:

- producers focusing their drilling and completion in the most productive areas with favorable economics where we have significant gathering and processing assets; and
- continued producer improvements in production due to enhanced completion techniques and more efficient drilling rigs; offset partially by
- natural production declines.

We expect our natural gas volumes to continue to grow in 2018 due to the production activities discussed above.

Rocky Mountain region - In the Williston Basin, we have significant natural gas gathering and processing assets and substantial acreage dedications. Natural gas volumes increased in 2017, compared with 2016, due primarily to new supply and completion of growth projects, offset partially by the impact of severe winter weather in the first quarter 2017.

Mid-Continent region - In the Mid-Continent region, we have significant natural gas gathering and processing assets in Oklahoma and Kansas. We had higher natural gas gathered and processed volumes in 2017, compared with 2016, due to increased producer activity in the STACK and SCOOP areas, where we have substantial acreage dedications.

Demand - Demand for gathering and processing services is dependent on natural gas production by producers, which is driven by the strength of the economy; producer firm commitments to transportation pipelines; natural gas, crude oil and NGL prices; and the demand for each of these products from end users. We generally contract with crude oil and natural gas producers who have proven reserves or are currently producing natural gas in areas within our existing infrastructure and need gathering and processing services. Additionally, demand is impacted by the weather, which is discussed below under “Seasonality.”

Rocky Mountain region - Demand for our gathering and processing services in the Williston Basin has remained strong in both high and low commodity price environments. Requirements in North Dakota for producers to reduce natural gas flaring have increased the need for our services to capture, gather and process natural gas, and we are responding by constructing assets, such as our recently announced Demicks Lake natural gas processing plant and related infrastructure. We have approximately 125 MMcf/d of available capacity from our more than 1.0 Bcf/d of processing assets. Upon completion of the Demicks Lake plant, we will have more than 1.2 Bcf/d of processing capacity in this region.

Mid-Continent region - As producers continue to develop the STACK and SCOOP areas, we expect increased demand for our services. We have approximately 100 MMcf/d of available processing capacity in Oklahoma. We are responding to producers' needs by constructing assets, such as the 200 MMcf/d expansion of our Canadian Valley natural gas processing plant, which will increase our processing capacity to 1.2 Bcf/d in this region.

Commodity Prices - We have significantly reduced our direct exposure to commodity prices in this segment and our earnings are primarily fee-based.

See discussion regarding our commodity price risk and related hedging activities under “Commodity Price Risk” in Part II, Item 7A, Quantitative and Qualitative Disclosures about Market Risk.

Seasonality - Cold temperatures usually increase demand for natural gas and certain NGL products such as propane, the main heating fuels for homes and businesses. Warm temperatures usually increase demand for natural gas used in gas-fired electric generators for residential and commercial cooling, as well as agriculture-related equipment like irrigation pumps and crop dryers. During periods of peak demand for a certain commodity, prices for that product typically increase.

Extreme weather conditions and seasonal temperature changes impact the volumes and composition of natural gas gathered and processed. A freeze-off is a phenomenon where water produced with natural gas freezes at the wellhead or within the gathering system. This causes a temporary interruption in the flow of natural gas. Our operations may be affected by other weather conditions that may cause a loss of electricity at our facilities or prevent access to certain locations that affect a producer’s ability to produce oil and natural gas wells or our ability to connect new wells to our systems.

Competition - We compete for natural gas supply with other midstream gatherers and processors, major integrated oil companies, independent exploration and production companies that have gathering and processing assets, and pipeline companies and their affiliated marketing companies. The factors that typically affect our ability to compete for natural gas supply are:

- quality of services provided;
- producer drilling activity;
- proceeds remitted and/or fees charged under our gathering and processing contracts;
- location of our gathering systems relative to those of our competitors;
- location of our gathering systems relative to drilling activity;
- operating pressures maintained on our gathering systems;
- efficiency and reliability of our operations;
- delivery capabilities for natural gas and NGLs that exist in each system and plant location; and
- cost of capital.

We continue to evaluate opportunities to increase earnings and cash flows, and reduce risk by:

- improving natural gas processing efficiency;
- constructing new assets;
- reducing operating costs;
- consolidating assets; and
- decreasing commodity price exposure.

Customers - Our Natural Gas Gathering and Processing segment derives services revenue primarily from crude oil and natural gas producers, which include both large integrated and independent exploration and production companies. Our downstream commodity sales customers are primarily utilities, large industrial companies, marketing companies and our NGL affiliate. See discussion regarding our customer credit risk under “Counterparty Credit Risk” in Part II, Item 7A, Quantitative and Qualitative Disclosures about Market Risk.

Government Regulation - The FERC traditionally has maintained that a natural gas processing plant is not a facility for the transportation or sale of natural gas in interstate commerce and, therefore, is not subject to jurisdiction under the Natural Gas Act. Although the FERC has made no specific declaration as to the jurisdictional status of our natural gas processing operations or facilities, our natural gas processing plants are primarily involved in extracting NGLs and, therefore, are exempt from FERC jurisdiction. The Natural Gas Act also exempts natural gas gathering facilities from the jurisdiction of the FERC. We believe our natural gas gathering facilities and operations meet the criteria used by the FERC for nonjurisdictional natural gas gathering facility status. Interstate transmission facilities remain subject to FERC jurisdiction. The FERC has historically distinguished between these two types of facilities, either interstate or intrastate, on a fact-specific basis. We transport residue natural gas from certain of our natural gas processing plants to interstate pipelines in accordance with Section 311(a) of the Natural Gas Policy Act. Oklahoma, Kansas, Wyoming, Montana and North Dakota also have statutes regulating, to varying degrees, the gathering of natural gas in those states. In each state, regulation is applied on a case-by-case basis if a complaint is filed against the gatherer with the appropriate state regulatory agency.

See further discussion in the “Regulatory, Environmental and Safety Matters” section.

Natural Gas Liquids

Overview - Our Natural Gas Liquids segment owns and operates facilities that gather, fractionate, treat and distribute NGLs and store NGL products, primarily in Oklahoma, Kansas, Texas, New Mexico and the Rocky Mountain region, which includes the Williston, DJ and Powder River Basins, where we provide midstream services to producers of NGLs and deliver those products to the two primary market centers, one in the Mid-Continent in Conway, Kansas, and the other in the Gulf Coast in Mont Belvieu, Texas. We own or have an ownership interest in FERC-regulated natural gas liquids gathering and distribution pipelines in Oklahoma, Kansas, Texas, New Mexico, Montana, North Dakota, Wyoming and Colorado, and terminal and storage facilities in Missouri, Nebraska, Iowa and Illinois. We also own FERC-regulated natural gas liquids distribution and refined petroleum products pipelines in Kansas, Missouri, Nebraska, Iowa, Illinois and Indiana that connect our Mid-Continent assets with Midwest markets, including Chicago, Illinois. The majority of the pipeline-connected natural gas processing plants in Oklahoma, Kansas and the Texas Panhandle are connected to our natural gas liquids gathering systems. We own and operate truck- and rail-loading and -unloading facilities connected to our natural gas liquids fractionation and pipeline assets.

Most natural gas produced at the wellhead contains a mixture of NGL components, such as ethane, propane, iso-butane, normal butane and natural gasoline. The NGLs that are separated from the natural gas stream at natural gas processing plants remain in a mixed, unfractionated form until they are gathered, primarily by pipeline, and delivered to fractionators where the NGLs are separated into NGL products. These NGL products are then stored or distributed to our customers, such as petrochemical manufacturers, heating fuel users, ethanol producers, refineries, exporters and propane distributors.

Revenues - Revenues for our Natural Gas Liquids segment are derived primarily from commodity sales and fee-based services. We also purchase NGLs and condensate from third parties, as well as from our Natural Gas Gathering and Processing segment. Our fee-based services have increased due primarily to new supply connections, expansion of existing connections and the completion of capital-growth projects. Our business activities are categorized as exchange services, transportation and storage services, and optimization and marketing, which are defined as follows:

- Exchange services - we utilize our assets to gather, fractionate and/or treat, and transport unfractionated NGLs, thereby converting them into marketable NGL products shipped to a market center or customer-designated location. Many of these exchange volumes are under contracts with minimum volume commitments that provide a minimum level of revenues regardless of volumetric throughput. Our exchange services activities are primarily fee-based and include some rate-regulated tariffs; however, we also capture certain product price differentials through the fractionation process.
- Transportation and storage services - we transport NGL products and refined petroleum products, primarily under FERC-regulated tariffs. Tariffs specify the maximum rates we may charge our customers and the general terms and conditions for transportation service on our pipelines. Our storage activities consist primarily of fee-based NGL storage services at our Mid-Continent and Gulf Coast storage facilities.
- Optimization and marketing - we utilize our assets, contract portfolio and market knowledge to capture location, product and seasonal price differentials through the purchase and sale of NGLs and NGL products. We primarily transport NGL products between Conway, Kansas, and Mont Belvieu, Texas, to capture the location price differentials between the two market centers. Our marketing activities also include utilizing our natural gas liquids storage facilities to capture seasonal price differentials. A growing portion of our marketing activities serves truck and rail markets. Our isomerization activities capture the price differential when normal butane is converted into the more valuable iso-butane at our isomerization unit in Conway, Kansas.

In many of our exchange services contracts, we purchase the unfractionated NGLs at the tailgate of the processing plant and deduct contractual fees related to the transportation and fractionation services we must perform before we can sell them as NGL products. Upon adoption of Topic 606 in January 2018, these fees will be recorded as a reduction to the NGL purchase price in cost of sales and fuel. In 2017 and prior periods, we recorded these fees as exchange services revenue. We do not expect adoption of the standard to be material to this segment's operating income.

Supply growth from the development of NGL-rich areas and capacity available on pipelines that connect the Mid-Continent and Gulf Coast resulted in NGL price differentials remaining narrow between the Mid-Continent market center at Conway, Kansas, and the Gulf Coast market center at Mont Belvieu, Texas. We expect relatively narrow price differentials to persist between these two market centers until demand for NGLs increases from petrochemical companies and exporters, which we expect as ethylene producers continue to complete their expansion projects and international demand for NGLs increases export volumes.

Property - Our Natural Gas Liquids segment owns the following assets:

- approximately 2,800 miles of non-FERC-regulated natural gas liquids gathering pipelines with peak capacity of approximately 800 MBbl/d;
- approximately 170 miles of non-FERC-regulated natural gas liquids distribution pipelines with peak transportation capacity of approximately 66 MBbl/d;
- approximately 4,300 miles of FERC-regulated natural gas liquids gathering pipelines with peak capacity of approximately 683 MBbl/d;
- approximately 4,200 miles of FERC-regulated natural gas liquids and refined petroleum products distribution pipelines with peak capacity of 993 MBbl/d;
- one natural gas liquids fractionator in Oklahoma with operating capacity of approximately 210 MBbl/d, two natural gas liquids fractionators in Kansas with combined operating capacity of 280 MBbl/d and two natural gas liquids fractionators in Texas with combined operating capacity of 150 MBbl/d;
- 80 percent ownership interest in one natural gas liquids fractionator in Texas with our proportional share of operating capacity of approximately 128 MBbl/d;
- interest in one natural gas liquids fractionator in Kansas with our proportional share of operating capacity of approximately 11 MBbl/d;
- one isomerization unit in Kansas with operating capacity of 9 MBbl/d;
- six natural gas liquids storage facilities in Oklahoma, Kansas and Texas with operating storage capacity of approximately 22.2 MMBbl;
- eight natural gas liquids product terminals in Nebraska, Iowa and Illinois;
- above- and below-ground storage facilities associated with our FERC-regulated natural gas liquids pipeline operations in Iowa, Illinois, Nebraska and Kansas with combined operating capacity of 978 MBbl; and
- one ethane/propane splitter in Texas with operating capacity of 32 MBbl/d of purity ethane and 8 MBbl/d of propane.

In addition, we lease approximately 3.5 MMBbl of combined NGL storage capacity at facilities in Kansas and Texas and have access to 60 MBbl/d of natural gas liquids fractionation capacity in Texas through a fractionation service agreement.

Utilization - The utilization rates for our various assets, including leased assets, have been impacted by ethane rejection. The utilization rates for 2017 and 2016, respectively, were as follows:

- our non-FERC-regulated natural gas liquids gathering pipelines were approximately 73 percent and 66 percent;
- our FERC-regulated natural gas liquids gathering pipelines were approximately 78 percent and 77 percent;
- our FERC-regulated natural gas liquids distribution pipelines were approximately 57 percent and 56 percent; and
- our natural gas liquids fractionators were approximately 74 percent and 70 percent.

We calculate utilization rates using a weighted-average approach, adjusting for the dates that assets were placed in service. Our fractionation utilization rate reflects approximate proportional capacity associated with our ownership interests.

Unconsolidated Affiliates - Our Natural Gas Liquids segment includes the following unconsolidated affiliates:

- 50 percent ownership interest in Overland Pass Pipeline Company, which operates an interstate natural gas liquids pipeline system extending approximately 760 miles, originating in Wyoming and Colorado and terminating in Kansas;
- 50 percent ownership interest in Chisholm Pipeline Company, which operates an interstate natural gas liquids pipeline system extending approximately 185 miles from origin points in Oklahoma and terminating in Kansas; and
- 50 percent ownership interest in Heartland Pipeline Company, which operates a terminal and pipeline system that transports refined petroleum products in Kansas, Nebraska and Iowa.

See Note N of the Notes to Consolidated Financial Statements in this Annual Report for additional discussion of unconsolidated affiliates.

Market Conditions and Seasonality - Supply - The unfractionated NGLs that we gather and transport originate primarily from natural gas processing plants connected to our natural gas liquids gathering systems in Oklahoma, Kansas, Texas, New Mexico and the Rocky Mountain region. Our Natural Gas Liquids segment is the largest NGL takeaway provider for the STACK and SCOOP areas and the Williston Basin. Our fractionation operations receive NGLs from a variety of processors and pipelines, including our affiliates, located in these regions. Supply for our Natural Gas Liquids segment depends on crude oil and natural gas drilling and production activities by producers, the decline rate of existing production, natural gas processing plant economics and capabilities, and the NGL content of the natural gas that is produced and processed in the areas in which we operate.

Supply growth has resulted in available ethane supply that is greater than the petrochemical industry's current demand. Low or unprofitable price differentials between ethane and natural gas have resulted in varied levels of ethane rejection at most of our and our customers' natural gas processing plants connected to our NGL system in the Mid-Continent and Rocky Mountain regions. Ethane rejection levels across our system averaged more than 150 MBbl/d in 2017, which is slightly lower than 2016 despite an increase in overall supply volumes. We expect ethane rejection on our system to decrease to approximately 70 MBbl/d by the end of 2018, initially in regions closest to market centers such as the Permian Basin and Mid-Continent region, as ethylene producers continue to complete their expansion projects and NGL exporters increase their export volumes in 2018 and beyond.

Demand - Demand for NGLs and the ability of natural gas processors to successfully and economically sustain their operations affect the volume of unfractionated NGLs produced by natural gas processing plants, thereby affecting the demand for NGL gathering, fractionation and transportation services. Natural gas and propane are subject to weather-related seasonal demand. Other NGL products are affected by economic conditions and the demand associated with the various industries that utilize the commodity, such as butanes and natural gasoline used by the refining industry as blending stocks for motor fuel, denaturant for ethanol and diluents for crude oil. Ethane, propane, normal butane and natural gasoline are used by the petrochemical industry to produce chemical products, such as plastic, rubber and synthetic fibers. Several petrochemical companies are constructing new plants, plant expansions, additions or enhancements that improve the light-NGL feed capability of their facilities due primarily to the increased supply and attractive price of ethane, compared with crude oil-based alternatives, as a petrochemical feedstock in the United States. The demand for NGLs is expected to continue to increase from petrochemical companies and exporters in the coming months as ethylene producers complete their expansion projects and international demand for NGLs increases export volumes. Increasing producer activity in high-production areas is driving the need for additional gathering and fractionation services, such as our recently announced Sterling III and WTLPG pipeline expansions, Elk Creek pipeline, Arbuckle II pipeline and MB-4 projects.

Commodity Prices - Our Natural Gas Liquids segment provides primarily fee-based services. However, we are exposed to market risk associated with changes in the price of NGLs; the location differential between the Mid-Continent, Chicago, Illinois, and Gulf Coast regions; and the relative price differential between natural gas, NGLs and individual NGL products, which affect our NGL purchases and sales, and our exchange services, transportation and storage services, and optimization and marketing financial results. Supply growth from the development of NGL-rich areas and capacity available on pipelines that connect the Mid-Continent and Gulf Coast resulted in 2017 NGL price differentials remaining narrow between the Mid-Continent market center at Conway, Kansas, and the Gulf Coast market center at Mont Belvieu, Texas. However, location price differentials for the fourth quarter 2017 were some of the widest that we have experienced since 2012. NGL storage revenue may be affected by price volatility and forward pricing of NGL physical contracts versus the price of NGLs on the spot market.

Seasonality - Our natural gas liquids fractionation and pipeline operations typically experience some seasonal variation. Some NGL products stored and transported through our assets are subject to weather-related seasonal demand, such as propane, which can be used for heating during the winter and for agricultural purposes such as crop drying in the fall. Demand for butanes and natural gasoline, which are primarily used by the refining industry as blending stocks for motor fuel, denaturant for ethanol and diluents for crude oil, may also be subject to some variability during seasonal periods when certain government restrictions on motor fuel blending products change. The ability of natural gas processors to produce NGLs also is affected by weather. Extreme weather conditions and ground temperature changes impact the volumes of natural gas gathered and processed and NGL volumes gathered, transported and fractionated. Power interruptions, inaccessible well sites as a result of severe storms or freeze-offs, a phenomenon where water produced from natural gas freezes at the wellhead or within the gathering system, cause a temporary interruption in the flow of natural gas and NGLs.

Competition - Our Natural Gas Liquids segment competes with other fractionators, intrastate and interstate pipeline companies, storage providers, and gatherers and transporters for NGL supply in the Permian Basin and Rocky Mountain, Mid-Continent and Gulf Coast regions. The factors that typically affect our ability to compete for NGL supply are:

- quality of services provided;
- producer drilling activity;
- the petrochemical industry's level of capacity utilization and feedstock requirements;
- fees charged under our contracts;
- current and forward NGL prices;
- location of our gathering systems relative to our competitors;
- location of our gathering systems relative to drilling activity;
- proximity to NGL supply areas and markets;
- efficiency and reliability of our operations;
- receipt and delivery capabilities that exist in each pipeline system, plant, fractionator and storage location; and

- cost of capital.

We have responded to these factors by making capital investments to access new supplies; increasing gathering, fractionation and distribution capacity; increasing storage, withdrawal and injection capabilities; and reducing operating costs so that we may compete effectively. Our competitors continue to invest in natural gas liquids pipeline and fractionation infrastructure to address the growing NGL supply and petrochemical demand. As our growth projects and those of our competitors have alleviated constraints between the Mid-Continent and Gulf Coast NGL market centers, we expect relatively narrow price differentials between these two market centers to persist until demand for NGLs increases from petrochemical companies and exporters. In addition, our and our competitors' natural gas liquids infrastructure projects provide NGL supply from the Rocky Mountain region, Marcellus and Utica basins into the Gulf Coast market center, which affects NGL prices and competes with and could displace NGL supply volumes from the Mid-Continent and Rocky Mountain regions where our assets are located. We believe our natural gas liquids fractionation, pipelines and storage assets are located strategically, connecting diverse supply areas to market centers.

Customers - Our Natural Gas Liquids segment's customers are primarily NGL and natural gas gathering and processing companies; major and independent crude oil and natural gas production companies; propane distributors; ethanol producers; and petrochemical, refining and NGL marketing companies. See discussion regarding our customer credit risk under "Counterparty Credit Risk" in Part II, Item 7A, Quantitative and Qualitative Disclosures about Market Risk.

Government Regulation - The operations and revenues of our natural gas liquids pipelines are regulated by various state and federal government agencies. Our interstate natural gas liquids pipelines are regulated by the FERC, which has authority over the terms and conditions of service; rates, including depreciation and amortization policies; and initiation of service. In Oklahoma, Kansas and Texas, certain aspects of our intrastate natural gas liquids pipelines that provide common carrier service are subject to the jurisdiction of the OCC, KCC and RRC, respectively.

PHMSA has asserted jurisdiction over certain portions of our fractionation facilities in Bushton, Kansas, that it believes are subject to its jurisdiction. We have objected to the scope of PHMSA's jurisdiction and are seeking resolution of this matter. We do not anticipate that the cost of compliance will have a material adverse effect on our consolidated results of operations, financial position or cash flows.

See further discussion in the "Regulatory, Environmental and Safety Matters" section.

Natural Gas Pipelines

Overview - Our Natural Gas Pipelines segment provides transportation and storage services to end users through its wholly owned assets and its 50 percent ownership interests in Northern Border Pipeline and Roadrunner.

Interstate Pipelines - Our interstate pipelines are regulated by the FERC and are located in North Dakota, Minnesota, Wisconsin, Illinois, Indiana, Kentucky, Tennessee, Oklahoma, Texas and New Mexico. Our interstate pipeline companies include:

- Midwestern Gas Transmission, which is a bidirectional system that interconnects with Tennessee Gas Transmission Company's pipeline near Portland, Tennessee, and with several interstate pipelines that have access to both the Utica Shale and the Marcellus Shale at the Chicago Hub near Joliet, Illinois;
- Viking Gas Transmission, which is a bidirectional system that interconnects with a TransCanada Corporation pipeline at the United States border near Emerson, Canada, and ANR Pipeline Company near Marshfield, Wisconsin;
- Guardian Pipeline, which interconnects with several pipelines at the Chicago Hub near Joliet, Illinois, and with local natural gas distribution companies in Wisconsin; and
- OkTex Pipeline, which has interconnections with several pipelines in Oklahoma, Texas and New Mexico.

Intrastate Pipelines - Our intrastate natural gas pipeline assets in Oklahoma transport natural gas through the state and have access to the major natural gas production areas in the Mid-Continent region, which include the STACK and SCOOP areas and the Cana-Woodford Shale, Woodford Shale, Springer Shale, Meramec, Granite Wash and Mississippian Lime formations. Our intrastate natural gas pipeline assets in Oklahoma serve end-use markets, such as local distribution companies and power generation companies. In Texas, our intrastate natural gas pipelines are connected to the major natural gas producing formations in the Texas Panhandle, including the Granite Wash formation and Delaware, Cline and Midland producing formations in the Permian Basin. These pipelines are capable of transporting natural gas throughout the western portion of Texas, including the Waha Hub where other pipelines may be accessed for transportation to western markets, exports to

Mexico, the Houston Ship Channel market to the east and the Mid-Continent market to the north. Our intrastate natural gas pipeline assets also have access to the Hugoton and Central Kansas Uplift Basins in Kansas.

Revenues - Revenues in this segment are derived primarily from transportation and storage services.

Our transportation revenues are primarily fee-based from the following types of services:

- Firm service - Customers reserve a fixed quantity of pipeline capacity for a specified period of time, which obligates the customer to pay regardless of usage. Under this type of contract, the customer pays a monthly fixed fee and incremental fees, known as commodity charges, which are based on the actual volumes of natural gas they transport or store. Under the firm service contract, the customer generally is guaranteed access to the capacity they reserve.
- Interruptible service - Under interruptible service transportation agreements, the customer may utilize available capacity after firm service requests are satisfied. The customer is not guaranteed use of our pipelines unless excess capacity is available.

Our regulated natural gas transportation services contracts are based upon rates stated in the respective tariffs, which have generally been established through shipper specific negotiation, discounts and negotiated settlements. The rates are filed with FERC or the appropriate state jurisdictional agencies. In addition, customers typically are assessed fees, such as a commodity charge, and we may retain a percentage or specified volume of natural gas in-kind based on the natural gas volumes transported.

Our storage revenues are primarily fee-based from the following types of services:

- Firm service - Customers reserve a specific quantity of storage capacity, including injection and withdrawal rights, and generally pay fixed fees based on the quantity of capacity reserved plus an injection and withdrawal fee. Firm storage contracts typically have terms longer than one year.
- Park-and-loan service - An interruptible service offered to customers providing the ability to park (inject) or loan (withdraw) natural gas into or out of our storage, typically for monthly or seasonal terms. Customers reserve the right to park or loan natural gas based on a specified quantity, including injection and withdrawal rights when capacity is available.

We own natural gas storage facilities located in Texas and Oklahoma that are connected to our intrastate natural gas pipelines. We also have underground natural gas storage facilities in Kansas. In Texas and Kansas, natural gas storage operations may be regulated by the state in which the facility operates and by the FERC for certain types of services. In Oklahoma, natural gas storage operations are not subject to rate regulation by the state, and we have market-based rate authority from the FERC for certain types of services.

Property - Our Natural Gas Pipelines segment owns the following assets:

- approximately 1,500 miles of FERC-regulated interstate natural gas pipelines with approximately 3.5 Bcf/d of peak transportation capacity;
- approximately 5,200 miles of state-regulated intrastate transmission pipelines with peak transportation capacity of approximately 3.5 Bcf/d; and
- approximately 52.2 Bcf of total active working natural gas storage capacity.

Our storage includes two underground natural gas storage facilities in Oklahoma, two underground natural gas storage facilities in Kansas and two underground natural gas storage facilities in Texas.

Utilization - Our natural gas pipelines were approximately 94 percent and 92 percent subscribed in 2017 and 2016, respectively, and our natural gas storage facilities were 64 percent and 65 percent subscribed in 2017 and 2016, respectively.

Unconsolidated Affiliates - Our Natural Gas Pipelines segment includes the following unconsolidated affiliates:

- 50 percent interest in Northern Border Pipeline, which owns a FERC-regulated interstate pipeline that transports natural gas from the Montana-Saskatchewan border near Port of Morgan, Montana, and the Williston Basin in North Dakota to a terminus near North Hayden, Indiana.
- 50 percent interest in Roadrunner, which has the capacity to transport approximately 570 MMcf/d of natural gas from the Permian Basin in West Texas to the Mexican border near El Paso, Texas. We are the operator of Roadrunner.

See Note N of the Notes to Consolidated Financial Statements in this Annual Report for additional discussion of unconsolidated affiliates.

Market Conditions and Seasonality - Supply - The development of shale and other resource areas has continued to increase available natural gas supply across North America and has caused location and seasonal price differentials to narrow in the regions where we operate.

Interstate - Guardian Pipeline, Midwestern Gas Transmission and Viking Gas Transmission access supply from the major producing regions of the Mid-Continent, Rocky Mountains, Canada, Gulf Coast and the Northeast. The current supply of natural gas for Northern Border Pipeline is primarily sourced from Canada; however, as the Williston Basin supply area has developed, more natural gas supply from this area is being transported on Northern Border Pipeline to markets near Chicago. In addition, supply volumes from nontraditional natural gas production areas, such as the Marcellus and Utica shale areas in the Northeast, may compete with and displace volumes from the Mid-Continent, Rocky Mountain and Canadian supply sources in our markets. Factors that may impact the supply of Canadian natural gas transported by our pipelines are primarily the availability of United States supply, Canadian natural gas available for export, Canadian storage capacity, government regulation and demand for Canadian natural gas in Canada and United States consumer markets.

Intrastate and Storage - Our intrastate pipelines and storage assets may be impacted by the pace of drilling activity by crude oil and natural gas producers and the decline rate of existing production in the major natural gas production areas in the Permian Basin and the Mid-Continent region.

Demand - Demand for our services is related directly to our access to supply and the demand for natural gas by the markets that our natural gas pipelines and storage facilities serve. Demand is also affected by weather, the economy, natural gas price volatility and regulatory changes.

- Weather - The effect of weather on our natural gas pipelines operations is discussed below under "Seasonality."
- Economy - The strength of the economy directly impacts manufacturing and industrial companies that consume natural gas.
- Price volatility - Commodity price volatility can influence producers' decisions related to the production of natural gas. Our pipeline customers, primarily natural gas and electric utilities, require natural gas to operate their businesses and generally are not impacted by location price differentials. However, narrower location price differentials may impact demand for our services from natural gas marketers as discussed below under "Commodity Prices."
- Regulatory - Demand for our services is also affected as coal-fired electric generators are retired and replaced with power generation from natural gas. EPA regulations on emissions from coal-fired electric-generation plants have increased the demand for natural gas as a fuel for electric generation, as well as related transportation and storage services. The demand for natural gas and related transportation and storage services is expected to increase over the next several years as regulations continue to be implemented.

Commodity Prices - Although our revenues are primarily fee-based, commodity prices can affect our results of operations.

- Transportation - We are exposed to market risk through interruptible contracts or when existing firm contracts expire and are subject to renegotiation with customers that have competitive alternatives.
- Storage - Natural gas storage revenue is impacted by the differential between forward pricing of natural gas physical contracts and the price of natural gas on the spot market.
- Fuel - Our fuel costs and the value of the retained fuel in-kind received for our services also are impacted by changes in the price of natural gas.

Seasonality - Demand for natural gas is seasonal. Weather conditions throughout North America may significantly impact regional natural gas supply and demand. High temperatures may increase demand for gas-fired electric generation needed to meet the electricity demand required to cool residential and commercial properties. Cold temperatures may lead to greater demand for our transportation services due to increased demand for natural gas to heat residential and commercial properties. Low precipitation levels may impact the demand for natural gas that is used to fuel irrigation activity in the Mid-Continent region.

To the extent that pipeline capacity is contracted under firm-service transportation agreements, revenue, which is generated primarily from fixed-fee charges, is not significantly impacted by seasonal throughput variations.

Natural gas storage is necessary to balance the relatively steady natural gas supply with the seasonal demand of residential, commercial and electric-generation users. The majority of our storage capacity is either contracted under firm-service agreements or is used for park-and-loan services. We retain a portion of our storage capacity for operational purposes.

Competition - Our natural gas pipelines and storage facilities compete directly with other intrastate and interstate pipeline companies and other storage facilities. Competition among pipelines and natural gas storage facilities is based primarily on fees for services, quality and reliability of services provided, current and forward natural gas prices, proximity to natural gas supply areas and markets, and access to capital. Competition for natural gas transportation services continues to increase as new infrastructure projects are completed and the FERC and state regulatory bodies continue to encourage more competition in the natural gas markets. Regulatory bodies also are encouraging the use of natural gas for electric generation that has traditionally been fueled by coal. The combined cost of coal and the associated rail transportation continues to be competitive with the cost of natural gas; however, the clean-burning aspects of natural gas and abundance of supply make it an economically competitive and environmentally advantaged alternative. We believe that our pipelines and storage assets compete effectively due to their strategic locations connecting supply areas to market centers and other pipelines.

Customers - Our natural gas pipeline assets primarily serve local natural gas distribution companies, electric-generation facilities, large industrial companies, municipalities, producers and marketing companies. Our utility customers generally require our services regardless of commodity prices. See discussion regarding our customer credit risk under "Counterparty Credit Risk" in Part II, Item 7A, Quantitative and Qualitative Disclosures about Market Risk.

Government Regulation - *Interstate* - Our interstate natural gas pipelines are regulated under the Natural Gas Act, which gives the FERC jurisdiction to regulate virtually all aspects of this business, such as transportation of natural gas, rates and charges for services, construction of new facilities, depreciation and amortization policies, acquisition and disposition of facilities, and the initiation and discontinuation of services.

Intrastate - Our intrastate natural gas pipelines in Oklahoma, Kansas and Texas are regulated by the OCC, KCC and RRC, respectively, and by the FERC under the Natural Gas Policy Act for certain services where we deliver natural gas into FERC regulated natural gas pipelines. While we have flexibility in establishing natural gas transportation rates with customers, there is a maximum rate that we can charge our customers in Oklahoma and Kansas and for the services regulated by the FERC. In Texas and Kansas, natural gas storage may be regulated by the state and by the FERC for certain types of services. In Oklahoma, natural gas storage operations are not subject to rate regulation by the state, and we have market-based rate authority from the FERC for certain types of services.

See further discussion in the "Regulatory, Environmental and Safety Matters" section.

SEGMENT FINANCIAL INFORMATION

Segment Adjusted EBITDA, Customers and Total Assets - See Note P of the Notes to Consolidated Financial Statements in this Annual Report for disclosure by segment of our adjusted EBITDA and total assets and for a discussion of revenues from external customers.

Other

Through ONEOK Leasing Company, L.L.C. and ONEOK Parking Company, L.L.C., we own a 17-story office building (ONEOK Plaza) with approximately 505,000 square feet of net rentable space and a parking garage in downtown Tulsa, Oklahoma, where our headquarters are located. ONEOK Leasing Company, L.L.C. leases excess office space to others and operates our headquarters office building. ONEOK Parking Company, L.L.C. owns and operates a parking garage adjacent to our headquarters.

REGULATORY, ENVIRONMENTAL AND SAFETY MATTERS

Environmental Matters - We are subject to multiple federal, state, local and/or tribal historical preservation and environmental laws and/or regulations that affect many aspects of our present and future operations. Regulated activities include, but are not limited to, those involving air emissions, storm water and wastewater discharges, handling and disposal of solid and hazardous wastes, wetlands and waterways preservation, cultural resources protection, hazardous materials transportation, and pipeline and facility construction. These laws and regulations require us to obtain and/or comply with a wide variety of environmental clearances, registrations, licenses, permits and other approvals. Failure to comply with these laws, regulations, licenses and permits may expose us to fines, penalties and/or interruptions in our operations that could be material to our results of operations. For example, if a leak or spill of hazardous substances or petroleum products occurs from pipelines or facilities that we own, operate or otherwise use, we could be held jointly and severally liable for all resulting liabilities, including response, investigation and cleanup costs, which could affect materially our results of operations and cash flows. In addition, emissions controls and/or other regulatory or permitting mandates under the Clean Air Act and other similar federal and state laws could require unexpected capital expenditures at our facilities. We cannot assure that existing environmental statutes and regulations will not be revised or that new regulations will not be adopted or become applicable to us.

There is a belief that emissions of GHGs is linked to global climate change. GHG emissions originate primarily from combustion engine exhaust, heater exhaust and fugitive methane gas emissions. International, federal, regional and/or state legislative and/or regulatory initiatives may attempt to control or limit GHG emissions, including initiatives directed at issues associated with climate change. Various federal and state legislative proposals have been introduced to regulate the emission of GHGs, particularly carbon dioxide and methane, and the United States Supreme Court has ruled that carbon dioxide is a pollutant subject to regulation by the EPA. In addition, there have been international efforts seeking legally binding reductions in emissions of GHGs.

Our environmental and climate change actions focus on minimizing the impact of our operations on the environment. These actions include: (i) developing and maintaining an accurate GHG emissions inventory according to current rules issued by the EPA; (ii) improving the efficiency of our various pipelines, natural gas processing facilities and natural gas liquids fractionation facilities; (iii) following developing technologies for emissions control and the capture of carbon dioxide to keep it from reaching the atmosphere; and (iv) utilizing practices to reduce the loss of methane from our facilities.

We participate in the EPA's Natural Gas STAR Program to reduce voluntarily methane emissions. We continue to focus on maintaining low rates of lost-and-unaccounted-for methane gas through expanded implementation of best practices to limit the release of natural gas during pipeline and facility maintenance and operations.

We believe it is likely that future governmental legislation and/or regulation may require us either to limit GHG emissions from our operations or to purchase allowances for such emissions. However, we cannot predict precisely what form these future regulations will take, the stringency of the regulations or when they will become effective. In addition to activities on the federal level, state and regional initiatives could also lead to the regulation of GHG emissions sooner than and/or independent of federal regulation. These regulations could be more stringent than any federal legislation that may be adopted.

For additional information regarding the potential impact of laws and regulations on our operations see Item 1A "Risk Factors."

Pipeline Safety - We are subject to PHMSA safety regulations, including pipeline asset integrity-management regulations. The Pipeline Safety Improvement Act of 2002 requires pipeline companies operating high-pressure pipelines to perform integrity assessments on pipeline segments that pass through densely populated areas or near specifically designated high-consequence areas. The Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 (the 2011 Pipeline Safety Act) increased maximum penalties for violating federal pipeline safety regulations, directs the DOT and Secretary of Transportation to conduct further review or studies on issues that may or may not be material to us and may result in the imposition of more stringent regulations.

Since 2015, PHMSA has issued notices of proposed rule-making for hazardous liquid pipeline safety regulations, natural gas transmission and gathering lines and underground natural gas storage facilities, none of which have become final. The potential capital and operating expenditures related to the proposed regulations are unknown, but we do not anticipate a material impact to our planned capital, operations and maintenance costs resulting from compliance with the current or pending regulations.

Air and Water Emissions - The Clean Air Act, the Clean Water Act, analogous state laws and/or regulations impose restrictions and controls regarding the discharge of pollutants into the air and water in the United States. Under the Clean Air Act, a federally enforceable operating permit is required for sources of significant air emissions. We may be required to incur certain capital expenditures for air pollution-control equipment in connection with obtaining or maintaining permits and approvals for sources of air emissions. The Clean Water Act imposes substantial potential liability for the removal of pollutants discharged to waters of the United States and remediation of waters affected by such discharge.

International, federal, regional and/or state legislative and/or regulatory initiatives may attempt to control or limit GHG emissions, including initiatives directed at issues associated with climate change. We monitor all relevant legislation and regulatory initiatives to assess the potential impact on our operations and otherwise take efforts to limit GHG emissions from our facilities, including methane. The EPA's Mandatory Greenhouse Gas Reporting Rule requires annual GHG emissions reporting from affected facilities and the carbon dioxide emission equivalents for the natural gas delivered by us and the emission equivalents for all NGLs produced by us as if all of these products were combusted, even if they are used otherwise.

Our 2016 total reported emissions were approximately 50 million metric tons of carbon dioxide equivalents. This total includes direct emissions from the combustion of fuel in our equipment, such as compressor engines and heaters, as well as carbon dioxide equivalents from natural gas and NGL products delivered to customers and produced as if all such fuel and NGL products were combusted. The additional cost to gather and report this emission data did not have, and we do not expect it to have, a material impact on our results of operations, financial position or cash flows. In addition, Congress has considered, and may consider in the future, legislation to reduce GHG emissions, including carbon dioxide and methane. Likewise, the EPA may institute additional regulatory rule-making associated with GHG emissions from the oil and natural gas industry. At this time, no rule or legislation has been enacted that assesses any costs, fees or expenses on any of these emissions.

We closely monitor proposed and final rule-makings. At this time we do not anticipate a material impact to our planned capital, operations and maintenance costs resulting from compliance with the current or pending regulations and EPA actions. However, the EPA may issue additional regulations, responses, amendments and/or policy guidance, which could alter our present expectations. Generally, EPA rule-makings require expenditures for updated emissions controls, monitoring and recordkeeping requirements at affected facilities.

Chemical Site Security - The United States Department of Homeland Security (Homeland Security) released the Chemical Facility Anti-Terrorism Standards in 2007, and the new final rule associated with these regulations was issued in December 2014. We provided information regarding our chemicals via Top-Screens submitted to Homeland Security, and our facilities subsequently were assigned one of four risk-based tiers ranging from high (Tier 1) to low (Tier 4) risk, or not tiered at all due to low risk. To date, one of our facilities has been given a Tier 4 rating. Facilities receiving a Tier 4 rating are required to complete Site Security Plans and possible physical security enhancements. We do not expect the Site Security Plans and possible security enhancement costs to have a material impact on our results of operations, financial position or cash flows.

Pipeline Security - The United States Department of Homeland Security's Transportation Security Administration and the DOT have completed a review and inspection of our "critical facilities" and identified no material security issues. Also, the Transportation Security Administration has released new pipeline security guidelines that include broader definitions for the determination of pipeline "critical facilities." We have reviewed our pipeline facilities according to the new guideline requirements, and there have been no material changes required to date.

EMPLOYEES

At January 31, 2018, we employed 2,470 people.

EXECUTIVE OFFICERS

All executive officers are elected annually by our Board of Directors. Our executive officers listed below include the officers who have been designated by our Board of Directors as our Section 16 executive officers.

Name and Position	Age		Business Experience in Past Five Years
John W. Gibson	65	2014 to present	Chairman of the Board, ONEOK
Chairman of the Board		2014 to 2017	Chairman of the Board, ONEOK Partners
		2011 to 2014	Chairman and Chief Executive Officer, ONEOK and ONEOK Partners
Terry K. Spencer	58	2014 to present	President and Chief Executive Officer, ONEOK
President and Chief Executive Officer		2014 to 2017	President and Chief Executive Officer, ONEOK Partners
		2014 to present	Member of the Board of Directors, ONEOK
		2014 to 2017	Member of the Board of Directors, ONEOK Partners
		2012 to 2014	President, ONEOK and ONEOK Partners
Robert F. Martinovich	60	2015 to present	Executive Vice President and Chief Administrative Officer, ONEOK
Executive Vice President and Chief Administrative Officer		2015 to 2017	Executive Vice President and Chief Administrative Officer, ONEOK Partners
		2014 to 2015	Executive Vice President, Commercial, ONEOK and ONEOK Partners
		2013 to 2014	Executive Vice President, Operations, ONEOK and ONEOK Partners
		2012	Executive Vice President, Chief Financial Officer and Treasurer, ONEOK and ONEOK Partners
		2011 to 2012	Member of the Board of Directors, ONEOK Partners
Walter S. Hulse III	54	2017 to present	Chief Financial Officer and Executive Vice President, Strategic Planning and Corporate Affairs, ONEOK
Chief Financial Officer, Executive Vice President, Strategic Planning and Corporate Affairs		2015 to 2017	Executive Vice President, Strategic Planning and Corporate Affairs, ONEOK and ONEOK Partners
		2012 to 2015	Managing Member, Spinnaker Strategic Advisory Services, LLC
Kevin L. Burdick	53	2017 to present	Executive Vice President and Chief Operating Officer, ONEOK
Executive Vice President and Chief Operating Officer		2017	Executive Vice President and Chief Commercial Officer, ONEOK and ONEOK Partners
		2016 to 2017	Senior Vice President, Natural Gas Gathering and Processing, ONEOK Partners
		2013 to 2016	Vice President, Natural Gas Gathering and Processing, ONEOK Partners
		2009 to 2013	Vice President and Chief Information Officer, ONEOK and ONEOK Partners
Wesley J. Christensen	64	2014 to present	Senior Vice President, Operations, ONEOK
Senior Vice President, Operations		2011 to 2017	Senior Vice President, Operations, ONEOK Partners
Stephen B. Allen	44	2017 to present	Senior Vice President, General Counsel and Assistant Secretary, ONEOK
Senior Vice President, General Counsel and Assistant Secretary		2008 to 2017	Vice President and Associate General Counsel, ONEOK and ONEOK Partners
Derek S. Reiners	46	2017 to present	Senior Vice President, Finance and Treasurer, ONEOK
Senior Vice President, Finance and Treasurer		2013 to 2017	Senior Vice President, Chief Financial Officer and Treasurer, ONEOK and ONEOK Partners
		2009 to 2012	Senior Vice President and Chief Accounting Officer, ONEOK and ONEOK Partners
Sheppard F. Miers III	49	2013 to present	Vice President and Chief Accounting Officer, ONEOK
Vice President and Chief Accounting Officer		2013 to 2017	Vice President and Chief Accounting Officer, ONEOK Partners
		2009 to 2012	Vice President and Controller, ONEOK Partners

No family relationships exist between any of the executive officers, nor is there any arrangement or understanding between any executive officer and any other person pursuant to which the officer was selected.

INFORMATION AVAILABLE ON OUR WEBSITE

We make available, free of charge, on our website (www.oneok.com) copies of our Annual Reports, Quarterly Reports, Current Reports on Form 8-K, amendments to those reports filed or furnished to the SEC pursuant to Section 13(a) or 15(d) of the Exchange Act and reports of holdings of our securities filed by our officers and directors under Section 16 of the Exchange Act as soon as reasonably practicable after filing such material electronically or otherwise furnishing it to the SEC. Copies of our Code of Business Conduct and Ethics, Corporate Governance Guidelines, Director Independence Guidelines, Bylaws and the written charter of our Audit Committee also are available on our website, and we will provide copies of these documents upon request.

We also use Twitter®, LinkedIn® and Facebook® as additional channels of distribution to reach public investors. Information contained on our website, posted on our social media accounts, and any corresponding applications, are not incorporated by reference into this report.

We also make available on our website the Interactive Data Files required to be submitted and posted pursuant to Rule 405 of Regulation S-T.

ITEM 1A. RISK FACTORS

Our investors should consider the following risks that could affect us and our business. Although we have tried to identify key factors, our investors need to be aware that other risks may prove to be important in the future. New risks may emerge at any time, and we cannot predict such risks or estimate the extent to which they may affect our financial performance. Investors should consider carefully the following discussion of risks and the other information included or incorporated by reference in this Annual Report, including "Forward-Looking Statements," which are included in Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations.

RISKS INHERENT IN OUR BUSINESS

If the level of drilling in the regions in which we operate declines substantially near our assets, our volumes and revenues could decline.

Our gathering and transportation pipeline systems are connected to, and dependent on the level of production from, natural gas and crude oil wells, from which production will naturally decline over time. As a result, our cash flows associated with these wells will also decline over time. In order to maintain or increase throughput levels on our gathering and transportation pipeline systems and the asset utilization rates at our processing and fractionation plants, we must continually obtain new supplies. Our ability to maintain or expand our businesses depends largely on the level of drilling and production by third parties in the regions in which we operate. Our natural gas and NGL supply volumes may be impacted if producers curtail or redirect drilling and production activities. Drilling and production are impacted by factors beyond our control, including:

- demand and prices for natural gas, NGLs and crude oil;
- producers' access to capital;
- producers' finding and development costs of reserves;
- producers' desire and ability to obtain necessary permits in a timely and economic manner;
- natural gas field characteristics and production performance;
- surface access and infrastructure issues; and
- capacity constraints on natural gas, crude oil and natural gas liquids infrastructure from the producing areas and our facilities.

Commodity prices have experienced significant volatility. Drilling and production activity levels may vary across our geographic areas; however, a prolonged period of low commodity prices may reduce drilling and production activities across all areas. If we are not able to obtain new supplies to replace the natural decline in volumes from existing wells or because of competition, throughput on our gathering and transportation pipeline systems and the utilization rates of our processing and fractionation facilities would decline, which could have a material adverse effect on our business, results of operations, financial position and cash flows, and our ability to pay cash dividends.

Continued development of new supply sources could impact demand for our services.

The discovery of nonconventional natural gas production areas near certain market areas that we serve may compete with natural gas originating in production areas connected to our systems. For example, the Marcellus Shale in Pennsylvania, New York, West Virginia and Ohio may cause natural gas in supply areas connected to our systems to be diverted to markets other than our traditional market areas and may affect capacity utilization adversely on our pipeline systems and our ability to renew or replace existing contracts at rates sufficient to maintain current revenues and cash flows. In addition, supply volumes from these nonconventional natural gas production areas may compete with and displace volumes from the Mid-Continent, Permian, Rocky Mountains and Canadian supply sources in certain of our markets. In our Natural Gas Gathering and Processing segment, the development of these new nonconventional reserves could move drilling rigs from our current service areas to other areas, which may reduce demand for our services. In our Natural Gas Pipelines segment, the displacement of natural gas originating in supply areas connected to our pipeline systems by these new supply sources that are closer to the end-use markets could result in lower transportation revenues, which could have a material adverse impact on our business, financial condition, results of operations and cash flows.

The volatility of natural gas, crude oil and NGL prices could affect adversely our earnings and cash flows.

A significant portion of our revenues are derived from the sale of commodities that are received in conjunction with natural gas gathering and processing services, the transportation and storage of natural gas, and from the purchase and sale of NGLs and NGL products. Commodity prices have been volatile and are likely to continue to be so in the future. The prices we receive for our commodities are subject to wide fluctuations in response to a variety of factors beyond our control, including, but not limited to, the following:

- overall domestic and global economic conditions;
- relatively minor changes in the supply of, and demand for, domestic and foreign energy;
- market uncertainty;
- the availability and cost of third-party transportation, natural gas processing and fractionation capacity;
- the level of consumer product demand and storage inventory levels;
- ethane rejection;
- geopolitical conditions impacting supply and demand for natural gas, NGLs and crude oil;
- weather conditions;
- domestic and foreign governmental regulations and taxes;
- the price and availability of alternative fuels;
- speculation in the commodity futures markets;
- the effects of imports and exports on the price of natural gas, crude oil, NGL and liquefied natural gas;
- the effect of worldwide energy-conservation measures;
- the impact of new supplies, new pipelines, processing and fractionation facilities on location price differentials; and
- technology and improved efficiency impacting supply and demand for natural gas, NGLs and crude oil.

These external factors and the volatile nature of the energy markets make it difficult to reliably estimate future prices of commodities and the impact commodity price fluctuations have on our customers and their need for our services, which could have a material adverse effect on our earnings and cash flows. As commodity prices decline, we could be paid less for our commodities, thereby reducing our cash flows. In addition, crude oil, natural gas and NGL production could also decline due to lower prices.

Market volatility and capital availability could affect adversely our business.

The capital and global credit markets have experienced volatility and disruption in the past. In many cases during these periods, the capital markets have exerted downward pressure on equity values and reduced the credit capacity for certain companies. Much of our business is capital intensive, and our ability to grow is dependent, in part, upon our ability to access capital at rates and on terms we determine to be attractive. Similar or more severe levels of global market disruption and volatility may have an adverse effect on us resulting from, but not limited to, disruption of our access to capital and credit markets, difficulty in obtaining financing necessary to expand facilities or acquire assets, increased financing costs and increasingly restrictive covenants. If we are unable to access capital at competitive rates, our strategy of enhancing the earnings potential of our existing assets, including through capital-growth projects and acquisitions of complementary assets or businesses, may be affected adversely. A number of factors could affect adversely our ability to access capital, including: (i) general economic conditions; (ii) capital market conditions; (iii) market prices for natural gas, NGLs and other hydrocarbons; (iv) the overall health of the energy and related industries; (v) ability to maintain investment-grade credit ratings; (vi) share price and (vii) capital structure. If our ability to access capital becomes constrained significantly, our interest costs and cost of equity will likely increase and could affect adversely our financial condition and future results of operations.

Our operating results may be affected materially and adversely by unfavorable economic and market conditions.

Economic conditions worldwide have from time to time contributed to slowdowns in the crude oil and natural gas industry, as well as in the specific segments and markets in which we operate, resulting in reduced demand and increased price competition for our products and services. Our operating results in one or more geographic regions may also be affected by uncertain or changing economic conditions within that region. Volatility in commodity prices may have an impact on many of our customers, which, in turn, could have a negative impact on their ability to meet their obligations to us. If global economic and market conditions (including volatility in commodity markets) or economic conditions in the United States or other key markets remain uncertain or persist, spread or deteriorate further, we may experience material impacts on our business, financial condition, results of operations and liquidity.

Increased competition could have a significant adverse financial impact on our business.

The natural gas and natural gas liquids industries are expected to remain highly competitive. The demand for natural gas and NGLs is primarily a function of commodity prices, including prices for alternative energy sources, customer usage rates, weather, economic conditions and service costs. Our ability to compete also depends on a number of other factors, including competition from other companies for our existing customers; the efficiency, quality and reliability of the services we provide; and competition for throughput at our gathering systems, pipelines, processing plants, fractionators and storage facilities.

Increased regulation of exploration and production activities, including hydraulic fracturing and disposal of waste water, could result in reductions or delays in drilling and completing new crude oil and natural gas wells, which could impact adversely our earnings by decreasing the volumes of natural gas and NGLs transported on our or our joint ventures' natural gas and natural gas liquids pipelines.

The natural gas industry is relying increasingly on natural gas supplies from nonconventional sources, such as shale and tight sands. Natural gas extracted from these sources frequently requires hydraulic fracturing, which involves the pressurized injection of water, sand and chemicals into a geologic formation to stimulate natural gas production. Legislation or regulations placing restrictions on hydraulic fracturing activities, including waste-water disposal, could impose operational delays, increased operating costs and additional regulatory burdens on exploration and production operators, which could reduce their production of unprocessed natural gas and, in turn, affect adversely our revenues and results of operations by decreasing the volumes of unprocessed natural gas and NGLs gathered, treated, processed, fractionated and transported on our or our joint ventures' natural gas and natural gas liquids pipelines, several of which gather unprocessed natural gas from areas where the use of hydraulic fracturing is prevalent.

In the competition for supply, we may have significant levels of excess capacity on our natural gas and natural gas liquids pipelines, processing, fractionation and storage assets.

Our natural gas and natural gas liquids pipelines, processing, fractionation and storage assets compete with other pipelines, processing, fractionation and storage facilities for natural gas and NGL supply delivered to the markets we serve. As a result of competition, we may have significant levels of uncontracted or discounted capacity on our pipelines, processing, fractionation and in our storage assets, which could have a material adverse impact on our results of operations and cash flows.

We may not be able to replace, extend or add additional contracted volumes on favorable terms, or at all, which could affect our financial condition, the amount of cash available to pay dividends and our ability to grow.

Although many of our customers and suppliers are subject to long-term contracts, if we are unable to replace or extend such contracts, add additional customers and suppliers or otherwise increase the contracted volumes of natural gas and NGLs provided to us by current producers, in each case on favorable terms, if at all, our financial condition, growth plans and the amount of cash available to pay dividends could be affected adversely. Our ability to replace, extend or add additional customer or supplier contracts, or increase contracted volumes of natural gas and NGLs from current producers, on favorable terms, or at all, is subject to a number of factors, some of which are beyond our control, including:

- the level of existing and new competition in our businesses or from alternative fuel sources, such as electricity, coal, fuel oils or nuclear energy;
- natural gas and NGL prices, demand, availability; and
- margins in our markets.

We may face opposition to the construction or operation of our pipelines and facilities from various groups.

We may face opposition to the construction or operation of our pipelines and facilities from environmental groups, landowners, tribal groups, local groups and other advocates. Such opposition could take many forms, including organized protests, attempts to block or sabotage our construction activities or operations, intervention in regulatory or administrative proceedings involving our assets, or lawsuits or other actions designed to prevent, disrupt or delay the construction or operation of our assets and business. For example, repairing our pipelines often involves securing consent from individual landowners to access their property; one or more landowners may resist our efforts to make needed repairs, which could lead to an interruption in the operation of the affected pipeline or facility for a period of time that is significantly longer than would have otherwise been the case. In addition, acts of sabotage or terrorism could cause significant damage or injury to people, property or the environment or lead to extended interruptions of our operations. Any such event that delays or interrupts the construction of assets or revenues generated by our existing operations, or which causes us to make significant expenditures not covered by insurance, could affect adversely our financial condition, results of operations, cash flows and our share price.

Growing our business by constructing new pipelines and plants or making modifications to our existing facilities subjects us to construction risk and supply risks, should adequate natural gas or NGL supply be unavailable upon completion of the facilities.

One of the ways we may grow our businesses is through the construction of new pipelines and new gathering, processing, storage and fractionation facilities and through modifications to our existing pipelines and existing gathering, processing, storage and fractionation facilities. The construction and modification of pipelines and gathering, processing, storage and fractionation facilities may face the following risks:

- projects may require significant capital expenditures, which may exceed our estimates, and involves numerous regulatory, environmental, political, legal and weather-related uncertainties;
- projects may increase demand for labor, materials and rights of way, which may, in turn, affect our costs and schedule;
- we may be unable to obtain new rights of way to connect new natural gas or NGL supplies to our existing gathering or transportation pipelines;
- if we undertake these projects, we may not be able to complete them on schedule or at the budgeted cost;
- our revenues may not increase immediately upon the expenditure of funds on a particular project. For instance, if we build a new pipeline, the construction will occur over an extended period of time, and we will not receive any material increases in revenues until after completion of the project;
- we may have only limited natural gas or NGL supply committed to these facilities prior to their construction;
- we may construct facilities to capture anticipated future growth in production in a region in which anticipated production growth does not materialize;
- we may rely on estimates of proved reserves in our decision to construct new pipelines and facilities, which may prove to be inaccurate because there are numerous uncertainties inherent in estimating quantities of proved reserves; and
- we may be required to rely on third parties downstream of our facilities to have available capacity for our delivered natural gas or NGLs, which may not yet be operational.

As a result, new facilities may not be able to attract enough natural gas or NGLs to achieve our expected investment return, which could affect materially and adversely our results of operations, financial condition and cash flows.

Our operations are subject to operational hazards and unforeseen interruptions, which could affect materially and adversely our business and for which we may not be adequately insured.

Our operations are subject to all of the risks and hazards typically associated with the operation of natural gas and natural gas liquids gathering, transportation and distribution pipelines, storage facilities and processing and fractionation plants. Operating risks include, but are not limited to, leaks, pipeline ruptures, the breakdown or failure of equipment or processes and the performance of pipeline facilities below expected levels of capacity and efficiency. Other operational hazards and unforeseen interruptions include adverse weather conditions, accidents, explosions, fires, the collision of equipment with our pipeline facilities (for example, this may occur if a third party were to perform excavation or construction work near our facilities) and catastrophic events such as tornados, hurricanes, earthquakes, floods or other similar events beyond our control. It is also possible that our facilities could be direct targets or indirect casualties of an act of terrorism. A casualty occurrence might result in injury or loss of life, extensive property damage or environmental damage. Liabilities incurred and interruptions to the operations of our pipeline or other facilities caused by such an event could reduce revenues generated by us and increase expenses, thereby impairing our ability to meet our obligations. Insurance proceeds may not be adequate to cover all liabilities or expenses incurred or revenues lost, and we are not fully insured against all risks inherent to our business.

As a result of market conditions, premiums and deductibles for certain insurance policies can increase substantially, and, in some instances, certain insurance may become unavailable or available only for reduced amounts of coverage. Consequently, we may not be able to renew existing insurance policies or purchase other desirable insurance on commercially reasonable terms, if at all. If we were to incur a significant liability for which we were not fully insured, it could have a material adverse effect on our financial position, cash flows and results of operations. Further, the proceeds of any such insurance may not be paid in a timely manner and may be insufficient if such an event were to occur.

We may not be able to develop and execute growth projects and acquire new assets, which could result in reduced dividends to our shareholders.

Our ability to maintain and grow our dividends paid to our shareholders depends on the growth of our existing businesses and strategic acquisitions. Our ability to make strategic acquisitions and investments will depend on:

- the extent to which acquisitions and investment opportunities become available;
- our success in bidding for the opportunities that do become available;
- regulatory approval, if required, of the acquisitions or investments on favorable terms; and
- our access to capital, including our ability to use our equity in acquisitions or investments, and the terms upon which we obtain capital.

Our ability to develop and execute growth projects will depend on our ability to implement business development opportunities and finance such activities on economically acceptable terms.

If we are unable to make strategic acquisitions and investments, integrate successfully businesses that we acquire with our existing business, or develop and execute our growth projects, our future growth will be limited, which could impact adversely our results of operations and cash flows and, accordingly, result in reduced cash dividends over time.

Acquisitions that appear to be accretive may nevertheless reduce our cash from operations on a per-share basis.

Any acquisition involves potential risks that may include, among other things:

- inaccurate assumptions about volumes, revenues and costs, including potential synergies;
- an inability to integrate successfully the businesses we acquire;
- decrease in our liquidity as a result of our using a significant portion of our available cash or borrowing capacity to finance the acquisition;
- a significant increase in our interest expense and/or financial leverage if we incur additional debt to finance the acquisition;
- the assumption of unknown liabilities for which we are not indemnified, our indemnity is inadequate or our insurance policies may exclude from coverage;
- an inability to hire, train or retain qualified personnel to manage and operate the acquired business and assets;
- limitations on rights to indemnity from the seller;
- inaccurate assumptions about the overall costs of equity or debt;
- the diversion of management's and employees' attention from other business concerns;
- unforeseen difficulties operating in new product areas or new geographic areas;
- increased regulatory burdens;
- customer or key employee losses at an acquired business; and
- increased regulatory requirements.

If we consummate any future acquisitions, our capitalization and results of operations may change significantly, and investors will not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in determining the application of our resources to future acquisitions.

Mergers between our customers, suppliers and competitors could result in lower volumes being gathered, processed, fractionated, transported or stored on our assets, thereby reducing the amount of cash we generate.

Mergers between our existing customers, suppliers and our competitors could provide strong economic incentives for the combined entities to utilize their existing gathering, processing, fractionation and/or transportation systems instead of ours in those markets where the systems compete. As a result, we could lose some or all of the volumes and associated revenues from these counterparties, and we could experience difficulty in replacing those lost volumes. Because most of our operating costs are fixed, a reduction in volumes could result not only in lower net income but also in a decline in cash flows, which would reduce our ability to pay cash dividends to our shareholders.

We do not own all of the land on which our pipelines and facilities are located, and we lease certain facilities and equipment, which could disrupt our operations.

We do not own all of the land on which certain of our pipelines and facilities are located, and we are, therefore, subject to the risk of increased costs to maintain necessary land use. We obtain the rights to construct and operate certain of our pipelines and related facilities on land owned by third parties and governmental agencies for a specific period of time. Our loss of these rights, through our inability to renew right-of-way contracts on acceptable terms or increased costs to renew such rights, could have a material adverse effect on our financial condition, results of operations and cash flows.

Terrorist attacks directed at our facilities could affect adversely our business.

The United States government has issued warnings that energy assets, specifically the nation's pipeline infrastructure, may be future targets of terrorist organizations. These developments may subject our operations to increased risks. Any future terrorist attack that may target our facilities, those of our customers and, in some cases, those of other pipelines, could have a material adverse effect on our business.

Any reduction in our credit ratings could affect materially and adversely our business, financial condition, liquidity and results of operations.

Our long-term debt and our commercial paper program have been assigned an investment-grade credit rating of "Baa3" and Prime-3, respectively, by Moody's and "BBB" and A-2, respectively, by S&P. We cannot provide assurance that any of our current ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances in the future so warrant. Specifically, if Moody's or S&P were to downgrade our long-term debt or our commercial paper rating, particularly below investment grade, our borrowing costs would increase, which would affect adversely our financial results, and our potential pool of investors and funding sources could decrease. Ratings from credit agencies are not recommendations to buy, sell or hold our securities. Each rating should be evaluated independently of any other rating.

Holders of our common stock may not receive dividends in the amount identified in guidance, or any dividends at all.

We may not have sufficient cash each quarter to pay dividends or maintain current or expected levels of dividends. The actual amount of cash we pay in the form of dividends may fluctuate from quarter to quarter and will depend on various factors, some of which are beyond our control, including our working capital needs, our ability to borrow, the restrictions contained in our indentures and credit facility, our debt service requirements and the cost of acquisitions, if any. A failure either to pay dividends or to pay dividends at expected levels could result in a loss of investor confidence, reputational damage and a decrease in the value of our stock price.

Our operating cash flows are derived partially from cash distributions we receive from our unconsolidated affiliates.

Our operating cash flows are derived partially from cash distributions we receive from our unconsolidated affiliates, as discussed in Note N of the Notes to Consolidated Financial Statements. The amount of cash that our unconsolidated affiliates can distribute principally depends upon the amount of cash flows these affiliates generate from their respective operations, which may fluctuate from quarter to quarter. We do not have any direct control over the cash distribution policies of our unconsolidated affiliates. This lack of control may contribute to us not having sufficient available cash each quarter to continue paying dividends at the current levels.

Additionally, the amount of cash that we have available for cash dividends depends primarily upon our cash flows, including cash flows from financial reserves and working capital borrowings, and is not solely a function of profitability, which will be affected by noncash items such as depreciation, amortization and provisions for asset impairments. As a result, we may be able to pay cash dividends during periods when we record losses and may not be able to pay cash dividends during periods when we record net income.

We are exposed to the credit risk of our customers or counterparties, and our credit risk management may not be adequate to protect against such risk.

We are subject to the risk of loss resulting from nonpayment and/or nonperformance by our customers and counterparties. Our customers or counterparties may experience rapid deterioration of their financial condition as a result of changing market conditions, commodity prices or financial difficulties that could impact their creditworthiness or ability to pay us for our services. We assess the creditworthiness of our customers and counterparties and obtain collateral or contractual terms as we deem appropriate. We cannot, however, predict to what extent our business may be impacted by deteriorating market or financial conditions, including possible declines in our customers' and counterparties' creditworthiness. Our customers and counterparties may not perform or adhere to our existing or future contractual arrangements. To the extent our customers and counterparties are in financial distress or commence bankruptcy proceedings, contracts with them may be subject to renegotiation or rejection under applicable provisions of the United States Bankruptcy Code. If we fail to assess adequately the creditworthiness of existing or future customers and counterparties any material nonpayment or nonperformance by our customers and counterparties due to inability or unwillingness to perform or adhere to contractual arrangements could have a material adverse impact on our business, results of operations, financial condition and ability to pay cash dividends to our shareholders.

Our primary market areas are located in the Mid-Continent, Rocky Mountain, Permian Basin and Gulf Coast regions of the U.S. Our counterparties are primarily major integrated and independent exploration and production, pipeline, marketing and petrochemical companies. Therefore our customers and counterparties may be similarly affected by changes in economic, regulatory or other factors that may affect our overall credit risk.

Our established risk-management policies and procedures may not be effective, and employees may violate our risk-management policies.

We have developed and implemented a comprehensive set of policies and procedures that involve both our senior management and our Audit Committee to assist us in managing risks associated with, among other things, the marketing, trading and risk-management activities associated with our business segments. Our risk-management policies and procedures are intended to align strategies, processes, people, information technology and business knowledge so that risk is managed throughout the organization. As conditions change and become more complex, current risk measures may fail to assess adequately the relevant risk due to changes in the market and the presence of risks previously unknown to us. Additionally, if employees fail to adhere to our policies and procedures or if our policies and procedures are not effective, potentially because of future conditions or risks outside of our control, we may be exposed to greater risk than we had intended. Ineffective risk-management policies and procedures or violation of risk-management policies and procedures could have an adverse effect on our earnings, financial position or cash flows.

Our businesses are subject to market and credit risks.

We are exposed to market and credit risks in all of our operations. To reduce the impact of commodity price fluctuations, we may use derivative instruments, such as swaps, puts, futures and forwards, to hedge anticipated purchases and sales of natural gas, NGLs, crude oil and firm transportation commitments. Interest-rate swaps are also used to manage interest-rate risk. However, derivative instruments do not eliminate the risks. Specifically, such risks include commodity price changes, market supply shortages, interest-rate changes and counterparty default. The impact of these variables could result in our inability to fulfill contractual obligations, significantly higher energy or fuel costs relative to corresponding sales contracts, or increased interest expense.

We do not hedge fully against commodity price changes, seasonal price differentials, product price differentials or location price differentials. This could result in decreased revenues, increased costs and lower margins, affecting adversely our results of operations.

Certain of our businesses are exposed to market risk and the impact of market fluctuations in natural gas, NGLs and crude oil prices. Market risk refers to the risk of loss of cash flows and future earnings arising from adverse changes in commodity prices. Our primary commodity price exposures arise from:

- the value of the commodities sold under POP with fee contracts of which we retain a portion of the sales proceeds;
- the price differentials between the individual NGL products with respect to our NGL transportation and fractionation agreements;
- the location price differentials in the price of natural gas and NGLs with respect to our natural gas and NGL transportation businesses;
- the seasonal price differentials in natural gas and NGLs related to our storage operations; and
- the fuel costs and the value of the retained fuel in-kind in our natural gas pipelines and storage operations.

To manage the risk from market price fluctuations in natural gas, NGLs and crude oil prices, we may use derivative instruments such as swaps, puts, futures, forwards and options. However, we do not hedge fully against commodity price changes, and we therefore retain some exposure to market risk. Accordingly, any adverse changes to commodity prices could result in decreased revenue and increased costs.

Our use of financial instruments and physical forward transactions to hedge market-risk exposure to commodity price and interest-rate fluctuations may result in reduced income.

We utilize financial instruments and physical forward transactions to mitigate our exposure to interest rate and commodity price fluctuations. Hedging instruments that are used to reduce our exposure to interest-rate fluctuations could expose us to risk of financial loss where we may contract for variable-rate swap instruments to hedge fixed-rate instruments and the variable rate exceeds the fixed rate. In addition, these hedging arrangements may limit the benefit we would otherwise receive if we had contracted for fixed-rate swap agreements to hedge variable-rate instruments and the variable rate falls below the fixed rate. Hedging arrangements for forecasted sales are used to reduce our exposure to commodity price fluctuations and limit the benefit we would otherwise receive if market prices for natural gas, crude oil and NGLs exceed the stated price in the hedge instrument for these commodities.

Changes in interest rates could affect adversely our business.

We use both fixed and variable rate debt, and we are exposed to market risk due to the floating interest rates on our short-term borrowings. From time to time we use interest-rate derivatives to hedge interest obligations on specific debt issuances, including anticipated debt issuances. These hedges may be ineffective, and our results of operations, cash flows and financial position could be affected adversely by significant fluctuations in interest rates from current levels.

Demand for natural gas and for certain of our NGL products and services is highly weather sensitive and seasonal.

The demand for natural gas and for certain of our NGL products, such as propane, is weather sensitive and seasonal, with a portion of revenues derived from sales for heating during the winter months. Weather conditions influence directly the volume of, among other things, natural gas and propane delivered to customers. Deviations in weather from normal levels and the seasonal nature of certain of our segments can create variations in earnings and short-term cash requirements.

Energy efficiency and technological advances may affect the demand for natural gas and NGLs and affect adversely our operating results.

More strict local, state and federal energy-conservation measures in the future or technological advances in heating, including installation of improved insulation and the development of more efficient furnaces, energy generation or other devices could affect the demand for natural gas and NGLs and affect adversely our results of operations and cash flows.

A breach of information security, including a cybersecurity attack, or failure of one or more key information technology or operational systems, or those of third parties, may affect adversely our operations, financial results or reputation.

Our businesses are dependent upon our operational systems to process a large amount of data and complex transactions. The various uses of these IT systems, networks and services include, but are not limited to:

- controlling our plants and pipelines with industrial control systems including Supervisory Control and Data Acquisition (SCADA);
- collecting and storing customer, employee, investor and other stakeholder information and data;
- processing transactions;
- summarizing and reporting results of operations;
- hosting, processing and sharing confidential and proprietary research, business plans and financial information;
- complying with regulatory, legal or tax requirements;
- providing data security; and
- handling other processing necessary to manage our business.

If any of our systems are damaged, fail to function properly or otherwise become unavailable, we may incur substantial costs to repair or replace them and may experience loss or corruption of critical data and interruptions or delays in our ability to perform critical functions, which could affect adversely our business and results of operations. Our financial results could also be affected adversely if an employee causes our operational systems to fail, either as a result of inadvertent error or by deliberately tampering with or manipulating our operational systems. In addition, dependence upon automated systems may further increase the risk that operational system flaws, employee tampering or manipulation of those systems will result in losses that are difficult to detect.

Due to increased technology advances, we have become more reliant on technology to help increase efficiency in our businesses. We use software to help manage and operate our businesses, and this may subject us to increased risks. In recent years, there has been a rise in the number of cyberattacks on companies' network and information systems by both state-sponsored and criminal organizations, and as a result, the risks associated with such an event continue to increase. A significant failure, compromise, breach or interruption in our systems could result in a disruption of our operations, customer dissatisfaction, damage to our reputation and a loss of customers or revenues. If any such failure, interruption or similar event results in the improper disclosure of information maintained in our information systems and networks or those of our vendors, including personnel, customer and vendor information, we could also be subject to liability under relevant contractual obligations and laws and regulations protecting personal data and privacy. Efforts by us and our vendors to develop, implement and maintain security measures may not be successful in preventing these events from occurring, and any network and information systems-related events could require us to expend significant resources to remedy such event. Although we believe that we have robust information security procedures and other safeguards in place, as cyberthreats continue to evolve, we may be required to expend additional resources to continue to enhance our information security measures and/or to investigate and remediate information security vulnerabilities.

Cyberattacks against us or others in our industry could result in additional regulations. Current efforts by the federal government, such as the Improving Critical Infrastructure Cybersecurity executive order, and any potential future regulations could lead to increased regulatory compliance costs, insurance coverage cost or capital expenditures. We cannot predict the potential impact to our business or the energy industry resulting from additional regulations.

If we fail to maintain an effective system of internal controls, we may not be able to report accurately our financial results or prevent fraud. As a result, current and potential holders of our equity and debt securities could lose confidence in our financial reporting, which would harm our business and cost of capital.

Effective internal controls are necessary for us to provide reliable financial reports, prevent fraud and operate successfully as a public company. We cannot be certain that our efforts to maintain our internal controls will be successful, that we will be able to maintain adequate controls over our financial processes and reporting in the future or that we will be able to continue to comply with our obligations under Section 404 of the Sarbanes-Oxley Act of 2002. Any failure to maintain effective internal controls, or difficulties encountered in implementing or improving our internal controls, could harm our operating results or cause us to fail to meet our reporting obligations. Ineffective internal controls could also cause investors to lose confidence in our reported financial information, which would likely have a negative effect on the trading price of our equity interests.

Pipeline safety laws and regulations may impose significant costs and liabilities.

Pipeline safety legislation that was signed into law in 2012, the 2011 Pipeline Safety Act, directed the Secretary of Transportation to promulgate new safety regulations for natural gas and hazardous liquids pipelines, including expanded integrity management requirements, automatic or remote-controlled valve use, excess flow valve use, leak detection system installation, testing to confirm the material strength of certain pipelines and operator verification of records confirming the maximum allowable pressure of certain gas transmission pipelines. The 2011 Pipeline Safety Act also increased the maximum penalty for violation of pipeline safety regulations from $100,000 to $200,000 per violation per day and also from $1 million to $2 million for a related series of violations.

The 2011 Pipeline Safety Act, the Protecting our Infrastructure of Pipelines and Enhancing Safety Act or rules implementing such acts could cause us to incur capital and operating expenditures for pipeline replacements or repairs, additional monitoring equipment or more frequent inspections or testing of our pipeline facilities, preventive or mitigating measures and other tasks that could result in higher operating costs or capital expenditures as necessary to comply with such standards, which costs could be significant.

See further discussion in the “Regulatory, Environmental and Safety Matters” section.

Compliance with environmental regulations that we are subject to may be difficult and costly.

We are subject to multiple federal, state, local and/or tribal historical preservation and environmental laws and/or regulations that affect many aspects of our present and future operations. Regulated activities include, but are not limited to, those involving air emissions, storm water and wastewater discharges, handling and disposal of solid and hazardous wastes, wetlands and waterways preservation, cultural resources protection, hazardous materials transportation, and pipeline and facility construction. These laws and regulations require us to obtain and/or comply with a wide variety of environmental clearances, registrations, licenses, permits and other approvals. Failure to comply with these laws, regulations, licenses and permits may expose us to fines, penalties and/or interruptions in our operations that could be material to our results of operations. For example, if a leak or spill of hazardous substances or petroleum products occurs from our pipelines or facilities that we own, operate or otherwise use, we could be held jointly and severally liable for all resulting liabilities, including response, investigation and clean-up costs, which could affect materially our results of operations and cash flows. In addition, emissions controls and/or other regulatory or permitting mandates under the federal Clean Air Act and other similar federal and state laws could require unexpected capital expenditures at our facilities. We cannot assure that existing environmental statutes and regulations will not be revised or that new regulations will not be adopted or become applicable to us. Revised or additional regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from customers, could have a material adverse effect on our business, financial condition, cash flows and results of operations.

Our operations are subject to federal and state laws and regulations relating to the protection of the environment, which may expose us to significant costs and liabilities.

The risk of incurring substantial environmental costs and liabilities is inherent in our business. Our operations are subject to extensive federal, state and local laws and regulations governing the discharge of materials into, or otherwise relating to the protection of, the environment. Examples of these laws include:

- the Clean Air Act and analogous state laws that impose obligations related to air emissions;
- the Clean Water Act and analogous state laws that regulate discharge of wastewater from our facilities to state and federal waters;
- the federal Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) and analogous state laws that regulate the cleanup of hazardous substances that may have been released at properties currently or previously owned or operated by us or locations to which we have sent waste for disposal; and
- the federal Resource Conservation and Recovery Act and analogous state laws that impose requirements for the handling and discharge of solid and hazardous waste from our facilities.

Various federal and state governmental authorities, including the EPA, have the power to enforce compliance with these laws and regulations and the permits issued under them. Violators are subject to administrative, civil and criminal penalties, including civil fines, injunctions or both. Joint and several, strict liability may be incurred without regard to fault under the CERCLA, Resource Conservation and Recovery Act and analogous state laws for the remediation of contaminated areas.

There is an inherent risk of incurring environmental costs and liabilities in our business due to our handling of the products we gather, transport, process and store, air emissions related to our operations, past industry operations and waste disposal practices, some of which may be material. Private parties, including the owners of properties through which our pipeline systems pass, may have the right to pursue legal actions to enforce compliance as well as to seek damages for noncompliance with environmental laws and regulations or for personal injury or property damage arising from our operations. Some sites we operate are located near current or former third-party hydrocarbon storage and processing operations, and there is a risk that contamination has migrated from those sites to ours. In addition, increasingly strict laws, regulations and enforcement policies could increase significantly our compliance costs and the cost of any remediation that may become necessary, some of which may be material. Additional information is included under Item 1, Business, under "Regulatory, Environmental and Safety Matters" and in Note O of the Notes to Consolidated Financial Statements in this Annual Report.

Our insurance may not cover all environmental risks and costs or may not provide sufficient coverage in the event an environmental claim is made against us. Our business may be affected materially and adversely by increased costs due to stricter pollution-control requirements or liabilities resulting from noncompliance with required operating or other regulatory permits. New or revised environmental regulations might also affect materially and adversely our products and activities, and federal and state agencies could impose additional safety requirements, all of which could affect materially our profitability.

We may face significant costs to comply with the regulation of GHG emissions.

GHG emissions originate primarily from combustion engine exhaust, heater exhaust and fugitive methane gas emissions. International, federal, regional and/or state legislative and/or regulatory initiatives may attempt to control or limit GHG emissions, including initiatives directed at issues associated with climate change. Various federal and state legislative proposals have been introduced to regulate the emission of GHGs, particularly carbon dioxide and methane, and the United States Supreme Court has ruled that carbon dioxide is a pollutant subject to regulation by the EPA. In addition, there have been international efforts seeking legally binding reductions in emissions of GHGs.

We believe it is likely that future governmental legislation and/or regulation may require us either to limit GHG emissions associated with our operations or to purchase allowances for such emissions. However, we cannot predict precisely what form these future regulations will take, the stringency of the regulations or when they will become effective. Several legislative bills have been introduced in the United States Congress that would require carbon dioxide emission reductions. Previously considered proposals have included, among other things, limitations on the amount of GHGs that can be emitted (so called "caps") together with systems of permitted emissions allowances. These proposals could require us to reduce emissions, even though the technology is not currently available for efficient reduction, or to purchase allowances for such emissions. Emissions also could be taxed independently of limits.

In addition to activities on the federal level, state and regional initiatives could also lead to the regulation of GHG emissions sooner than and/or independent of federal regulation. These regulations could be more stringent than any federal legislation that may be adopted.

Future legislation and/or regulation designed to reduce GHG emissions could make some of our activities uneconomic to maintain or operate. Further, we may not be able to pass on the higher costs to our customers or recover all costs related to complying with GHG regulatory requirements. Our future results of operations, cash flows or financial condition could be affected adversely if such costs are not recovered through regulated rates or otherwise passed on to our customers.

We continue to monitor legislative and regulatory developments in this area and otherwise take efforts to limit GHG emissions from our facilities, including methane. Although the regulation of GHG emissions may have a material impact on our operations and rates, we believe it is premature to attempt to quantify the potential costs of the impacts.

We may be subject to physical and financial risks associated with climate change.

There is a belief that emissions of GHGs is linked to global climate change. Climate change creates physical and financial risk. Our customers' energy needs vary with weather conditions, primarily temperature and humidity. For residential customers, heating and cooling represent their largest energy use. To the extent weather conditions may be affected by climate change, customers' energy use could increase or decrease depending on the duration and magnitude of any changes. Increased energy use due to weather changes may require us to invest in more pipelines and other infrastructure to serve increased demand. A decrease in energy use due to weather changes may affect our financial condition, through decreased revenues. Extreme weather conditions in general require more system backup, adding to costs, and can contribute to increased system stresses, including service interruptions. Weather conditions outside of our operating territory could also have an impact on our revenues. Severe weather impacts our operating territories primarily through hurricanes, thunderstorms, tornados and snow or ice storms. To the extent the frequency of extreme weather events increases, this could increase our cost of providing service. We may not be able to pass on the higher costs to our customers or recover all costs related to mitigating these physical risks. To the extent financial markets view climate change and emissions of GHGs as a financial risk, this could affect negatively our ability to access capital markets or cause us to receive less favorable terms and conditions in future financings. Our business could be affected by the potential for lawsuits against GHG emitters, based on links drawn between GHG emissions and climate change.

If production from the Western Canada Sedimentary Basin remains flat or declines and demand for natural gas from the Western Canada Sedimentary Basin is greater in market areas other than the Midwestern United States, demand for our interstate transportation services could decrease significantly.

We depend on a portion of natural gas supply from the Western Canada Sedimentary Basin for some of our interstate pipelines, primarily Viking Gas Transmission and our investment in Northern Border Pipeline, that transport Canadian natural gas from the Western Canada Sedimentary Basin to the Midwestern United States market area. If demand for natural gas increases in Canada or other markets not served by our pipelines and/or production remains flat or declines, demand for transportation service on our interstate natural gas pipelines could decrease significantly, which could impact adversely our business, financial condition, results of operations and cash flows.

Our business is subject to regulatory oversight and potential penalties.

The natural gas industry historically has been subject to heavy state and federal regulation that extends to many aspects of our businesses and operations, including:

- rates, operating terms and conditions of service;
- the types of services we may offer our counterparties;
- construction of new facilities;
- the integrity, safety and security of facilities and operations;
- acquisition, extension or abandonment of services or facilities;
- reporting and information posting requirements;
- maintenance of accounts and records; and
- relationships with affiliate companies involved in all aspects of the natural gas and energy businesses.

Compliance with these requirements can be costly and burdensome. Future changes to laws, regulations and policies in these areas may impair our ability to compete for business or to recover costs and may increase the cost and burden of operations.

We cannot guarantee that state or federal regulators will authorize any projects or acquisitions that we may propose in the future. Moreover, there can be no guarantee that, if granted, any such authorizations will be made in a timely manner or will be free from potentially burdensome conditions.

Failure to comply with all applicable state or federal statutes, rules and regulations and orders could bring substantial penalties and fines. For example, under the Energy Policy Act of 2005, the FERC has civil penalty authority under the Natural Gas Act to impose penalties for current violations of up to $1 million per day for each violation.

Finally, we cannot give any assurance regarding future state or federal regulations under which we will operate or the effect such regulations could have on our business, financial condition, results of operations and cash flows.

Our regulated pipelines' transportation rates are subject to review and possible adjustment by federal and state regulators.

Under the Natural Gas Act, which is applicable to interstate natural gas pipelines, and the Interstate Commerce Act, which is applicable to crude oil and natural gas liquids pipelines, our interstate transportation rates, which are regulated by the FERC, must be just and reasonable and not unduly discriminatory.

Under current policy, the FERC permits interstate pipelines that are subject to cost of service regulation to include an income tax allowance when calculating their regulated rates. The FERC's income tax allowance policy has been the subject of challenge, and we cannot predict whether the FERC or a reviewing court will alter the existing policy. For example, on July 1, 2016, the U.S. Court of Appeals for the District of Columbia Circuit issued a decision that calls into question a decade of FERC policy and precedent permitting regulated companies organized as pass-through entities for income tax purposes to include an allowance for income taxes in their rates. The court has remanded the case to the FERC to allow it to have an opportunity to provide a reasoned basis for its decision on income tax allowances for partnership pipelines. The FERC has issued a Notice of Inquiry seeking comments on proposed methods to adjust FERC's income tax policy. Comments were due in March 2017, but additional comments continue to be filed. If the FERC's policy were to change and if the FERC were to disallow a substantial portion of our pipelines' income tax allowance, our regulated rates, and therefore our revenues and ability to make quarterly cash dividends to our shareholders, could be affected adversely.

The Tax Cuts and Jobs Act may reduce future tariff rates charged on our regulated pipelines. If in the future the FERC or other regulatory bodies were to require a refund of previously collected amounts on our regulated pipelines related to this tax legislation, then we may be required to record a regulatory liability through a one-time charge to expense, which could be material.

If we were permitted to raise our tariff rates for a particular pipeline, there might be significant delay between the time the tariff rate increase is approved and the time that the rate increase actually goes into effect. Furthermore, competition from other pipeline systems may prevent us from raising our tariff rates even if regulatory agencies permit us to do so. The regulatory agencies that regulate our systems periodically implement new rules, regulations and terms and conditions of services subject to their jurisdiction. New initiatives or orders may affect adversely the rates charged for our services.

Finally, shippers may protest our pipeline tariff filings, and the FERC and or state regulatory agency may investigate tariff rates. Further, the FERC may order refunds of amounts collected under newly filed rates that are determined by the FERC to be in excess of a just and reasonable level. In addition, shippers may challenge by complaint the lawfulness of tariff rates that have become final and effective. The FERC and/or state regulatory agencies also may investigate tariff rates absent shipper complaint. Any finding that approved rates exceed a just and reasonable level on the natural gas pipelines would take effect prospectively. In a complaint proceeding challenging natural gas liquids pipeline rates, if the FERC determines existing rates exceed a just and reasonable level, it could require the payment of reparations to complaining shippers for up to two years prior to the complaint. Any such action by the FERC or a comparable action by a state regulatory agency could affect adversely our pipeline businesses' ability to charge rates that would cover future increases in costs, or even to continue to collect rates that cover current costs, and provide for a reasonable return. We can provide no assurance that our pipeline systems will be able to recover all of their costs through existing or future rates.

We are subject to comprehensive energy regulation by governmental agencies, and the recovery of our costs are dependent on regulatory action.

Federal, state and local agencies have jurisdiction over many of our activities, including regulation by the FERC of our interstate pipeline assets. The profitability of our regulated operations is dependent on our ability to pass through costs related to providing energy and other commodities to our customers by filing periodic rate cases. The regulatory environment applicable to our regulated businesses could impair our ability to recover costs historically absorbed by our customers.

We are unable to predict the impact that the future regulatory activities of these agencies will have on our operating results. Changes in regulations or the imposition of additional regulations could have an adverse impact on our business, financial condition, cash flows and results of operations.

Our regulated pipeline companies have recorded certain assets that may not be recoverable from our customers.

Accounting policies for FERC-regulated companies permit certain assets that result from the regulated rate-making process to be recorded on our balance sheet that could not be recorded under GAAP for nonregulated entities. We consider factors such as regulatory changes and the impact of competition to determine the probability of future recovery of these assets. If we determine future recovery is no longer probable, we would be required to write off the regulatory assets at that time.

Some of our nonregulated businesses have a higher level of risk than our regulated businesses.

Some of our nonregulated operations, which include our Natural Gas Gathering and Processing segment, much of our Natural Gas Liquids segment and a portion of our Natural Gas Pipelines segment, have a higher level of risk than our regulated operations, which includes a portion of our Natural Gas Pipelines segment and a portion of our Natural Gas Liquids segment. We expect to continue investing in natural gas and natural gas liquids projects and other related projects, some or all of which may involve nonregulated businesses or assets. These projects could involve risks associated with operational factors, such as competition and dependence on certain suppliers and customers; and financial, economic and political factors, such as rapid and significant changes in commodity prices, the cost and availability of capital and counterparty risk, including the inability of a counterparty, customer or supplier to fulfill a contractual obligation.

A shortage of skilled labor may make it difficult for us to maintain labor productivity and competitive costs, which could affect operations and cash flows available for dividends to our shareholders.

Our operations require skilled and experienced workers with proficiency in multiple tasks. In recent years, a shortage of workers trained in various skills associated with the midstream energy business has caused us to conduct certain operations without full staff, thus hiring outside resources, which may decrease productivity and increase costs. This shortage of trained workers is the result of experienced workers reaching retirement age and increased competition for workers in certain areas, combined with the difficulty of attracting new workers to the midstream energy industry. This shortage of skilled labor could continue over an extended period. If the shortage of experienced labor continues or worsens, it could have an adverse impact on our labor productivity and costs and our ability to expand production in the event there is an increase in the demand for our products and services, which could affect adversely our operations and cash flows available for dividends to our shareholders.

We are subject to strict regulations at many of our facilities regarding employee safety, and failure to comply with these regulations could affect adversely our business, financial position, results of operations and cash flows.

The workplaces associated with our facilities are subject to the requirements of OSHA and comparable state statutes that regulate the protection of the health and safety of workers. The failure to comply with OSHA requirements or general industry standards, including keeping adequate records or monitoring occupational exposure to regulated substances, could expose us to civil or criminal liability, enforcement actions, and regulatory fines and penalties and could have a material adverse effect on our business, financial position, results of operations and cash flows.

Measurement adjustments on our pipeline system may be impacted materially by changes in estimation, type of commodity and other factors.

Natural gas and natural gas liquids measurement adjustments occur as part of the normal operating conditions associated with our assets. The quantification and resolution of measurement adjustments are complicated by several factors including: (1) the significant quantities (*i.e.*, thousands) of measurement equipment that we use throughout our natural gas and natural gas liquids systems, primarily around our gathering and processing assets; (2) varying qualities of natural gas in the streams gathered and processed through our systems and the mixed nature of NGLs gathered and fractionated; and (3) variances in measurement that are inherent in metering technologies. Each of these factors may contribute to measurement adjustments that can occur on our systems, which could negatively affect our business, financial position, results of operations and cash flows.

Many of our pipeline and storage assets have been in service for several decades.

Many of our pipeline and storage assets are designed as long-lived assets. Over time the age of these assets could result in increased maintenance or remediation expenditures and an increased risk of product releases and associated costs and liabilities. Any significant increase in these expenditures, costs or liabilities could affect materially and adversely our results of operations, financial position or cash flows, as well as our ability to pay cash dividends.

We may be unable to cause our joint ventures to take or not to take certain actions unless some or all of our joint-venture participants agree.

We participate in several joint ventures. Due to the nature of some of these arrangements, each participant in these joint ventures has made substantial investments in the joint venture and, accordingly, has required that the relevant charter documents contain certain features designed to provide each participant with the opportunity to participate in the management of the joint venture and to protect its investment, as well as any other assets that may be substantially dependent on or otherwise affected by the activities of that joint venture. These participation and protective features customarily include a corporate governance structure that requires at least a majority-in-interest vote to authorize many basic activities and requires a greater voting interest (sometimes up to 100 percent) to authorize more significant activities. Examples of these more significant activities are large expenditures or contractual commitments, the construction or acquisition of assets, borrowing money or otherwise raising capital, transactions with affiliates of a joint-venture participant, litigation and transactions not in the ordinary course of business, among others. Thus, without the concurrence of joint-venture participants with enough voting interests, we may be unable to cause any of our joint ventures to take or not to take certain actions, even though those actions may be in the best interest of us or the particular joint venture.

Moreover, any joint-venture owner generally may sell, transfer or otherwise modify its ownership interest in a joint venture, whether in a transaction involving third parties or the other joint-venture owners. Any such transaction could result in us being required to partner with different or additional parties.

We do not operate all of our joint-venture assets nor do we employ directly all of the persons responsible for providing us with administrative, operating and management services. This reliance on others to operate joint-venture assets and to provide other services could affect adversely our business and operating results.

We rely on others to provide administrative, operating and management services for certain of our joint-venture assets. We have a limited ability to control the operations and the associated costs of such operations. The success of these operations depends on a number of factors that are outside our control, including the competence and financial resources of the provider. Some or all of these services may be outsourced to third parties, and a failure to perform by these third-party providers could lead to delays in or interruptions of these services. We may have to contract elsewhere for these services, which may cost more than we are currently paying. In addition, we may not be able to obtain the same level or kind of service or retain or receive the services in a timely manner, which may impact our ability to perform under our contracts and negatively affect our business and operating results. Our reliance on others to operate joint-venture assets, together with our limited ability to control certain costs, could harm our business and results of operations.

An impairment of goodwill, long-lived assets, including intangible assets, and equity-method investments could reduce our earnings.

Goodwill is recorded when the purchase price of a business exceeds the fair market value of the tangible and separately measurable intangible net assets. GAAP requires us to test goodwill for impairment on an annual basis or when events or circumstances occur indicating that goodwill might be impaired. Long-lived assets, including intangible assets with finite useful lives, are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. For the investments we account for under the equity method, the impairment test considers whether the fair value of the equity investment as a whole, not the underlying net assets, has declined and whether that decline is other than temporary. For example, if a low commodity price environment persisted for a prolonged period, it could result in lower volumes delivered to our systems and impairments of our assets or equity-method investments. If we determine that an impairment is indicated, we would be required to take an immediate noncash charge to earnings with a correlative effect on equity and balance sheet leverage as measured by consolidated debt to total capitalization.

Our indebtedness and guarantee obligations could impair our financial condition and our ability to fulfill our obligations.

As of December 31, 2017, we had total indebtedness of $9.2 billion. Our indebtedness and guarantee obligations could have significant consequences. For example, they could:

- make it more difficult for us to satisfy our obligations with respect to senior notes and other indebtedness due to the increased debt-service obligations, which could, in turn, result in an event of default on such other indebtedness or the senior notes;
- impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions or general business purposes;
- diminish our ability to withstand a downturn in our business or the economy;
- require us to dedicate a substantial portion of our cash flows from operations to debt-service payments, reducing the availability of cash for working capital, capital expenditures, acquisitions, dividends or general corporate purposes;
- limit our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate; and
- place us at a competitive disadvantage compared with our competitors that have proportionately less debt and fewer guarantee obligations.

We are not prohibited under the indentures governing the senior notes from incurring additional indebtedness, but our debt agreements do subject us to certain operational limitations summarized in the next paragraph. If we incur significant additional indebtedness, it could worsen the negative consequences mentioned above and could affect adversely our ability to repay our other indebtedness.

Our revolving debt agreements with banks contain provisions that restrict our ability to finance future operations or capital needs or to expand or pursue our business activities. For example, certain of these agreements contain provisions that, among other things, limit our ability to make loans or investments, make material changes to the nature of our business, merge, consolidate or engage in asset sales, grant liens or make negative pledges. Certain agreements also require us to maintain certain financial ratios, which limit the amount of additional indebtedness we can incur, as described in the "Liquidity and Capital Resources" section of Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operation. These restrictions could result in higher costs of borrowing and impair our ability to generate additional cash. Future financing agreements we may enter into may contain similar or more restrictive covenants.

If we are unable to meet our debt-service obligations, we could be forced to restructure or refinance our indebtedness, seek additional equity capital or sell assets. We may be unable to obtain financing or sell assets on satisfactory terms, or at all.

The right to receive payments on our outstanding debt securities and subsidiary guarantees is unsecured and will be effectively subordinated to our existing and future secured indebtedness as well as to any existing and future indebtedness of our subsidiaries that do not guarantee the senior notes.

Our debt securities are effectively subordinated to claims of our secured creditors, and the guarantees are effectively subordinated to the claims of our secured creditors as well as the secured creditors of our subsidiary guarantors. Although many of our operating subsidiaries have guaranteed such debt securities, the guarantees are subject to release under certain circumstances, and we may have subsidiaries that are not guarantors. In that case, the debt securities effectively would be subordinated to the claims of all creditors, including trade creditors and tort claimants, of our subsidiaries that are not guarantors. In the event of the insolvency, bankruptcy, liquidation, reorganization, dissolution or winding up of the business of a subsidiary that is not a guarantor, creditors of that subsidiary would generally have the right to be paid in full before any distribution is made to us or the holders of the debt securities.

An event of default may require us to offer to repurchase certain of our and ONEOK Partners' senior notes or may impair our ability to access capital.

The indentures governing certain of our and ONEOK Partners' senior notes include an event of default upon the acceleration of other indebtedness of $15 million or more for certain of our senior notes or $100 million or more for certain of our senior notes and ONEOK Partners' senior notes. Such events of default would entitle the trustee or the holders of 25 percent in aggregate principal amount of ONEOK Partners' outstanding senior notes to declare those senior notes immediately due and payable in full. We may not have sufficient cash on hand to repurchase and repay any accelerated senior notes, which may cause us to borrow money under our credit facility or seek alternative financing sources to finance the repurchases and repayment. We could also face difficulties accessing capital or our borrowing costs could increase, impacting our ability to obtain financing for acquisitions or capital expenditures, to refinance indebtedness and to fulfill our debt obligations.

A court may use fraudulent conveyance considerations to avoid or subordinate the cross guarantees of our and ONEOK Partners' indebtedness.

Various applicable fraudulent conveyance laws have been enacted for the protection of creditors. In connection with the closing of the Merger Transaction, ONEOK, ONEOK Partners and the Intermediate Partnership issued cross guarantees for our and ONEOK Partners' senior notes, borrowings under the $2.5 Billion Credit Agreement and the Term Loan Agreement and our commercial paper. A court may use fraudulent conveyance laws to subordinate or avoid the cross guarantees of certain of our and ONEOK Partners' indebtedness. It is also possible that under certain circumstances, a court could hold that the direct obligations of the guarantor could be superior to the obligations under that cross guarantee.

A court could avoid or subordinate the guarantor's guarantee of our and ONEOK Partners' indebtedness in favor of the guarantor's other debts or liabilities to the extent that the court determined either of the following were true at the time the guarantor issued the guarantee:

- the guarantor incurred the guarantee with the intent to hinder, delay or defraud any of its present or future creditors or the guarantor contemplated insolvency with a design to favor one or more creditors to the total or partial exclusion of others; or
- the guarantor did not receive fair consideration or reasonable equivalent value for issuing the guarantee and, at the time it issued the guarantee, the guarantor:
    - was insolvent or rendered insolvent by reason of the issuance of the guarantee;
    - was engaged or about to engage in a business or transaction for which its remaining assets constituted unreasonably small capital; or
    - intended to incur, or believed that it would incur, debts beyond its ability to pay such debts as they matured.

The measure of insolvency for purposes of the foregoing will vary depending upon the law of the relevant jurisdiction. Generally, however, an entity would be considered insolvent for purposes of the foregoing if:

- the sum of its debts, including contingent liabilities, were greater than the fair saleable value of all of its assets at a fair valuation;
- the present fair saleable value of its assets was less than the amount that would be required to pay its probable liability on its existing debts, including contingent liabilities, as they become absolute and mature; or
- it could not pay its debts as they become due.

Among other things, a legal challenge of the cross guarantees of our and ONEOK Partners' indebtedness on fraudulent conveyance grounds may focus on the benefits, if any, realized by the guarantor as a result of our and ONEOK Partners' issuance of such debt. To the extent the guarantor's guarantee of our and ONEOK Partners' indebtedness is avoided as a result of fraudulent conveyance or held unenforceable for any other reason, the holders of such debt would cease to have any claim in respect of the guarantee.

The cost of providing pension and postretirement health care benefits to eligible employees and qualified retirees is subject to changes in pension fund values and changing demographics and may increase.

We have a defined benefit pension plan for certain employees and postretirement welfare plans that provide postretirement medical and life insurance benefits to certain employees who retire with at least five years of service. The cost of providing these benefits to eligible current and former employees is subject to changes in the market value of our pension and postretirement benefit plan assets, changing demographics, including longer life expectancy of plan participants and their beneficiaries and changes in health care costs. For further discussion of our defined benefit pension plan, see Note L of the Notes to Consolidated Financial Statements in this Annual Report.

Any sustained declines in equity markets and reductions in bond yields may have a material adverse effect on the value of our pension and postretirement benefit plan assets. In these circumstances, additional cash contributions to our pension plans may be required, which could impact adversely our business, financial condition and liquidity.

TAX RISKS

Federal, state and local jurisdictions may challenge our tax return positions.

The positions taken in our federal and state tax return filings require significant judgments, use of estimates and the interpretation and application of complex tax laws. Significant judgment is also required in assessing the timing and amounts of deductible and taxable items. Despite management's belief that our tax return positions are fully supportable, certain positions may be successfully challenged by federal, state and local jurisdictions.

The separation of ONE Gas could result in substantial tax liability.

We have received a private letter ruling from the IRS substantially to the effect that, for U.S. federal income tax purposes, the separation and certain related transactions qualify under Sections 355 and/or 368 of the U.S. Internal Revenue Code of 1986, as amended. If the factual assumptions or representations made in the request for the private letter ruling prove to have been inaccurate or incomplete in any material respect, then we will not be able to rely on the ruling. Furthermore, the IRS does not rule on whether a distribution such as the separation satisfies certain requirements necessary to obtain tax-free treatment under section 355 of the Code. The private letter ruling was based on representations by us that those requirements were satisfied, and any inaccuracy in those representations could invalidate the ruling. In connection with the separation, we obtained an opinion of outside legal and tax counsel, substantially to the effect that, for U.S. federal income tax purposes, the separation and certain related transactions qualify under Sections 355 and 368 of the Code. The opinion relies on, among other things, the continuing validity of the private letter ruling and various assumptions and representations as to factual matters made by us which, if inaccurate or incomplete in any material respect, would jeopardize the conclusions reached by such counsel in its opinion. The opinion will not be binding on the IRS or the courts, and there can be no assurance that the IRS or the courts would not challenge the conclusions stated in the opinion or that any such challenge would not prevail.

ITEM 1B. UNRESOLVED STAFF COMMENTS

Not applicable.

ITEM 2. PROPERTIES

A description of our properties is included in Item 1, Business.

ITEM 3. LEGAL PROCEEDINGS

Information about our legal proceedings is included in Note O of the Notes to Consolidated Financial Statements in this Annual Report.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

MARKET INFORMATION AND HOLDERS

Our common stock is listed on the NYSE under the trading symbol "OKE." The corporate name ONEOK is used in newspaper stock listings. The following table sets forth the high and low closing prices of our common stock for the periods indicated:

	Year Ended December 31, 2017		Year Ended December 31, 2016	
	High	Low	High	Low
First Quarter	**$ 58.83**	**$ 52.20**	$ 30.82	$ 19.62
Second Quarter	**$ 56.33**	**$ 47.41**	$ 47.45	$ 28.37
Third Quarter	**$ 56.88**	**$ 50.36**	$ 51.39	$ 42.99
Fourth Quarter	**$ 56.70**	**$ 50.02**	$ 59.03	$ 46.44

At February 22, 2018, there were 13,480 holders of record of our 410,634,227 outstanding shares of common stock.

DIVIDENDS

The following table sets forth the quarterly dividends per share paid on our common stock in the periods indicated:

	Years Ended December 31,		
	2017	2016	2015
First Quarter	**$ 0.615**	$ 0.615	$ 0.605
Second Quarter	**0.615**	0.615	0.605
Third Quarter	**0.745**	0.615	0.605
Fourth Quarter	**0.745**	0.615	0.615
Total	**$ 2.72**	$ 2.46	$ 2.43

In February 2018, we paid a quarterly dividend of $0.77 per share ($3.08 per share on an annualized basis) to shareholders of record as of January 29, 2018.

EMPLOYEE STOCK AWARD PROGRAM

Under our Employee Stock Award Program, we issued, for no monetary consideration, to all eligible employees one share of our common stock when the per-share closing price of our common stock on the NYSE was for the first time at or above $13 per share, and one additional share of common stock when the per-share closing price of our common stock on the NYSE was at or above each one dollar increment above $13. No shares were issued to employees under this program during 2017, 2016 or 2015.

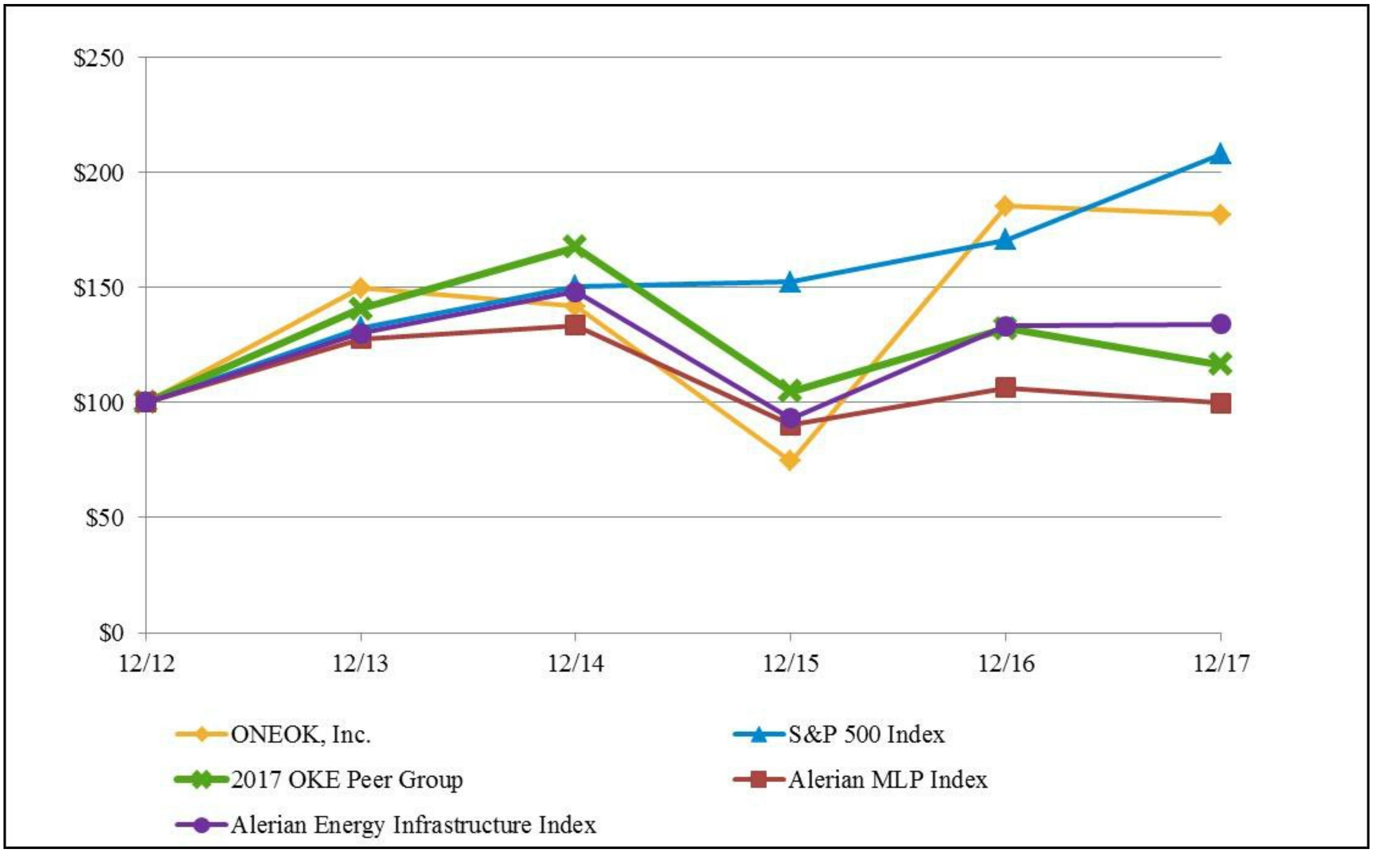
The total number of shares of our common stock available for issuance under this program is 900,000. The shares issued under this program have not been registered under the Securities Act, in reliance upon the position taken by the SEC (see Release No. 6188, dated February 1, 1980) that the issuance of shares to employees pursuant to a program of this kind does not require registration under the Securities Act. See Note K of the Notes to Consolidated Financial Statements in this Annual Report for additional information about the employee stock award program and other equity compensation plans.

PERFORMANCE GRAPH

The following performance graph compares the performance of our common stock with the S&P 500 Index, the Alerian Energy Infrastructure Index, the Alerian MLP Index and a ONEOK Peer Group during the period beginning on December 31, 2012, and ending on December 31, 2017.

The graph assumes a $100 investment in our common stock and in each of the indices at the beginning of the period and a reinvestment of dividends paid on such investments throughout the period.

Value of $100 Investment, Assuming Reinvestment of Distributions/Dividends,
at December 31, 2012, and at the End of Every Year Through December 31, 2017.



	Cumulative Total Return Years Ended December 31, 2013	2014	2015	2016	2017
ONEOK, Inc.	$ 149.68	$ 141.70	$ 74.52	$ 185.49	**$ 181.67**
S&P 500 Index	$ 132.36	$ 150.43	$ 152.51	$ 170.70	**$ 207.92**
ONEOK Peer Group (a)	$ 140.73	$ 167.47	$ 104.89	$ 132.17	**$ 116.57**
Alerian Energy Infrastructure Index (b)	$ 130.12	$ 148.17	$ 93.19	$ 133.34	**$ 133.99**
Alerian MLP Index	$ 127.60	$ 133.68	$ 90.21	$ 106.55	**$ 99.72**

(a) - The ONEOK Peer Group is comprised of the following companies: Boardwalk Pipeline Partners, LP; Buckeye Partners, L.P.; DCP Midstream, LP; Enbridge Energy Partners, L.P.; Energy Transfer Partners, L.P.; EnLink Midstream Partners, LP; Enterprise Products Partners L.P.; Kinder Morgan, Inc.; Magellan Midstream Partners, L.P.; MPLX LP; NuStar Energy L.P.; Plains All American Pipeline, L.P.; Targa Resources Corp.; and The Williams Companies, Inc.
(b) - The Alerian Energy Infrastructure Index measures the composite performance of more than 30 North American energy infrastructure companies who are engaged in midstream activities involving energy commodities. Following the Merger Transaction, we believe this index is a better benchmark for comparison than the Alerian MLP Index. We have included both indices in this transition year.

ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth our selected financial data for the periods indicated:

	Years Ended December 31,				
	2017	**2016**	**2015**	**2014**	**2013**
	(Millions of dollars, except per share data)				
Revenues	**$ 12,173.9**	$ 8,920.9	$ 7,763.2	$ 12,195.1	$ 11,871.9
Income from continuing operations	**$ 593.5**	$ 745.6	$ 385.3	$ 668.7	$ 589.1
Income from continuing operations attributable to ONEOK	**$ 387.8**	$ 354.1	$ 251.1	$ 319.7	$ 278.7
Net income attributable to ONEOK	**$ 387.8**	$ 352.0	$ 245.0	$ 314.1	$ 266.5
Total assets	**$ 16,845.9**	$ 16,138.8	$ 15,446.1	$ 15,261.8	$ 17,692.2
Long-term debt, including current maturities	**$ 8,524.3**	$ 8,330.6	$ 8,434.2	$ 7,160.8	$ 7,715.0
Earnings per share - continuing operations					
Basic	**$ 1.30**	$ 1.68	$ 1.19	$ 1.53	$ 1.35
Diluted	**$ 1.29**	$ 1.67	$ 1.19	$ 1.52	$ 1.33
Earnings per share - total					
Basic	**$ 1.30**	$ 1.67	$ 1.17	$ 1.50	$ 1.29
Diluted	**$ 1.29**	$ 1.66	$ 1.16	$ 1.49	$ 1.27
Dividends declared per share of common stock	**$ 2.72**	$ 2.46	$ 2.43	$ 2.125	$ 1.48

In the fourth quarter 2017, we recorded a one-time noncash charge to net income through income tax expense of $141.3 million, related to revaluation of our deferred tax balances and a valuation allowance on certain state net operating loss and tax credit carryforwards resulting from the enactment of the Tax Cuts and Jobs Act. For more information, see Note M in the Notes to the Consolidated Financial Statements.

Also in 2017, we incurred a $20.0 million noncash expense related to our Series E Preferred Stock contribution to the Foundation and operating costs related to the Merger Transaction of $30.0 million.

We recorded noncash impairment charges of $20.2 million, $264.3 million and $76.4 million in 2017, 2015 and 2014, respectively.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis should be read in conjunction with Part I, Item 1, Business, our audited Consolidated Financial Statements and the Notes to Consolidated Financial Statements in this Annual Report.

RECENT DEVELOPMENTS

Please refer to the "Financial Results and Operating Information" and "Liquidity and Capital Resources" sections of Management's Discussion and Analysis of Financial Condition and Results of Operations in this Annual Report for additional information.

Merger Transaction - On June 30, 2017, we completed the acquisition of all of the outstanding common units of ONEOK Partners that we did not already own at a fixed exchange ratio of 0.985 of a share of our common stock for each ONEOK Partners common unit. We issued 168.9 million shares of our common stock to third-party common unitholders of ONEOK Partners in exchange for all of the 171.5 million outstanding common units of ONEOK Partners that we previously did not own. As a result of the completion of the Merger Transaction, common units of ONEOK Partners are no longer publicly traded. The change in our ownership interest resulting from the Merger Transaction was accounted for as an equity transaction, and no gain or loss was recognized in our Consolidated Statement of Income.

Business Update and Market Conditions - We operate primarily fee-based businesses in each of our three reportable segments. Our consolidated earnings were approximately 90 percent fee-based in 2017, and we expect the same for 2018. In 2017, our Natural Gas Gathering and Processing segment's fee revenues averaged 86 cents per MMBtu, compared with an average of 76 cents and 44 cents per MMBtu in the same periods in 2016 and 2015, respectively, due to our contract restructuring efforts to mitigate commodity price risk and increasing volumes on those contracts with higher contracted fees.

Volumes gathered and processed increased across our asset footprint in our Natural Gas Gathering and Processing segment in 2017, compared with 2016, as producers experienced improved drilling economics, continued improvements in production due to enhanced completion techniques and more efficient drilling rigs. We connected six third-party natural gas processing plants in our Natural Gas Liquids segment in 2017, which, along with increased supply and ethane recovery, contributed to higher gathered NGL volumes in 2017, compared with 2016. We expect additional NGL volume growth as these plants continue to increase production and recently announced plant connections come online. Our fee-based transportation services in our Natural Gas Pipelines segment increased in 2017, compared with 2016, due primarily to higher firm transportation capacity contracted from our WesTex pipeline expansion.

Growth Projects - Increased producer activity and volume growth across our assets have increased demand for midstream infrastructure. We are responding to this growing demand by constructing assets to meet the needs of natural gas processors and producers across our asset footprint, including the Williston, DJ, Permian and Powder River Basins and the STACK and SCOOP areas. Since June 2017, we have announced approximately $4.2 billion of additional growth projects supported by long-term primarily fee-based contracts, minimum volume commitments and acreage dedications to serve the expected growth and needs of natural gas processors and producers. These projects are outlined in the table below:

Project	Scope	Approximate Costs (a)	Completion Date
		(*in millions*)	
Additional STACK processing capacity	200 MMcf/d processing capacity through long-term processing services agreement 30-mile natural gas gathering pipeline	$40	December 2017
WTLPG pipeline expansion	120-mile pipeline lateral extension with capacity of 110 MBbl/d in the Permian Basin Supported by long-term dedicated NGL production from two planned third-party natural gas processing plants	$160 (b)	Third Quarter 2018
Sterling III pipeline expansion and Arbuckle connection	60 MBbl/d NGL pipeline expansion Increases capacity to 250 MBbl/d Includes additional NGL gathering system expansions Supported by long-term third-party contract	$130	Fourth Quarter 2018
Canadian Valley expansion	200 MMcf/d processing plant expansion in the STACK area and related gathering infrastructure Increases capacity to 400 MMcf/d 20 MBbl/d additional NGL volume Supported by acreage dedications, long-term primarily fee-based contracts and minimum volume commitments	$160	Fourth Quarter 2018
Elk Creek pipeline and related infrastructure	900-mile NGL pipeline from the Williston Basin to the Mid-Continent region with initial capacity of 240 MBbl/d, and related infrastructure Anchored by by long-term contracts supported primarily by minimum volume commitments Expansion capability up to 400 MBbl/d with additional pump facilities	$1,400	Fourth Quarter 2019
Arbuckle II pipeline	530-mile NGL pipeline from the STACK area to Mont Belvieu, Texas, with initial capacity up to 400 MBbl/d, and related infrastructure Supported by long-term contracts Expansion capability up to 1,000 MBbl/d	$1,360	First Quarter 2020
MB-4 fractionator and related infrastructure	125 MBbl/d NGL fractionator in Mont Belvieu, Texas, and related infrastructure, which includes additional NGL storage in Mont Belvieu Fully contracted with long-term contracts	$575	First Quarter 2020
Demicks Lake plant and related infrastructure	200 MMcf/d processing plant and related infrastructure in the core of the Williston Basin Supported by acreage dedications with long-term primarily fee-based contracts	$400	Fourth Quarter 2019
Total		$4,225	

(a) Excludes capitalized interest/AFUDC.
(b) Represents our portion of the total project cost of $200 million.

Ethane Opportunity - Ethane rejection levels across our system averaged more than 150 MBbl/d in 2017, which is slightly lower than 2016 despite an increase in overall NGL supply volumes. We expect ethane rejection on our system to decrease to approximately 70 MBbl/d by the end of 2018, initially in regions closest to market centers such as the Permian Basin and Mid-Continent region, as ethylene producers complete their expansion projects and NGL exporters increase their export volumes. We expect this increase in ethane recovery to have a favorable impact on our financial results.

Income Taxes - The Tax Cuts and Jobs Act makes extensive changes to the U.S. tax laws and includes provisions that, beginning in 2018, reduce the U.S. corporate tax rate to 21 percent from 35 percent, increase expensing for capital investment, limit the interest deduction, and limit the use of net operating losses to offset future taxable income. We consider the aggregate of these changes as positive to our business and continue to expect that we will not pay federal cash income taxes through at least 2021. As a result of the enactment of the Tax Cuts and Jobs Act, we recorded a one-time noncash charge to net income through income tax expense of $141.3 million in the fourth quarter 2017, related to revaluation of our deferred tax balances and a valuation allowance on certain state net operating loss and tax credit carryforwards.

The Tax Cuts and Jobs Act may also impact future tariff rates charged on our regulated pipelines. The tariff rates charged on substantially all of our regulated pipelines have been established through shipper specific negotiation, discounts and negotiated settlements with rate moratoriums, which do not ascribe any specific cost of service elements, including income taxes. As such, we expect future tariff rate changes, if any, related to the change in U.S. corporate tax rate to be established prospectively over time on a similar negotiated basis. If in the future the FERC or other regulatory bodies were to require a refund of previously collected amounts on our regulated pipelines, then we may record a regulatory liability through a one-time charge to expense. For more information, see Note M in the Notes to the Consolidated Financial Statements.

Equity Issuances - In January 2018, we completed an underwritten public offering of 21.9 million shares of our common stock at a public offering price of $54.50 per share, generating net proceeds of $1.2 billion. We used the net proceeds from this offering to fund capital expenditures and for general corporate purposes, which included repaying a portion of our outstanding indebtedness. We have satisfied our expected equity financing needs through 2018 and well into 2019.

In July 2017, we established an "at-the-market" equity program for the offer and sale from time to time of our common stock up to an aggregate amount of $1 billion. The program allows us to offer and sell our common stock at prices we deem appropriate through a sales agent. Sales of our common stock may be made by means of ordinary brokers' transactions on the NYSE, in block transactions, or as otherwise agreed to between us and the sales agent. We are under no obligation to offer and sell common stock under the program. During the year ended December 31, 2017, we sold 8.4 million shares of common stock through our "at-the-market" equity program that resulted in net proceeds of $448.3 million.

Dividends - During 2017, we paid dividends totaling $2.72 per share, an increase of 11 percent from the $2.46 per share paid in 2016. In February 2018, we paid a quarterly dividend of $0.77 per share ($3.08 per share on an annualized basis), an increase of 25 percent compared with the same period in the prior year. We expect 85 to 95 percent of our 2018 dividend payments to investors to be a return of capital. Our dividend growth is due to the increase in cash flows resulting from the Merger Transaction and the continued growth of our operations.

FINANCIAL RESULTS AND OPERATING INFORMATION

Consolidated Operations

Selected Financial Results - The following table sets forth certain selected consolidated financial results for the periods indicated:

Financial Results	Years Ended December 31, 2017	2016	2015	Variances 2017 vs. 2016 Increase (Decrease)		Variances 2016 vs. 2015 Increase (Decrease)	
			(Millions of dollars)				
Revenues							
Commodity sales	**$ 9,862.7**	$ 6,858.5	$ 6,098.3	**$ 3,004.2**	**44 %**	$ 760.2	12 %
Services	**2,311.2**	2,062.4	1,665.0	**248.8**	**12 %**	397.4	24 %
Total revenues	**12,173.9**	8,920.9	7,763.3	**3,253.0**	**36 %**	1,157.6	15 %
Cost of sales and fuel (exclusive of items shown separately below)	**9,538.0**	6,496.1	5,641.1	**3,041.9**	**47 %**	855.0	15 %
Operating costs	**833.6**	757.1	693.3	**76.5**	**10 %**	63.8	9 %
Depreciation and amortization	**406.3**	391.6	354.6	**14.7**	**4 %**	37.0	10 %
Impairment of long-lived assets	**16.0**	—	83.7	**16.0**	*****	(83.7)	(100)%
Gain on sale of assets	**(0.9)**	(9.6)	(5.6)	**(8.7)**	**(91)%**	4.0	71 %
Operating income	**$ 1,380.9**	$ 1,285.7	$ 996.2	**$ 95.2**	**7 %**	$ 289.5	29 %
Equity in net earnings from investments	**$ 159.3**	$ 139.7	$ 125.3	**$ 19.6**	**14 %**	$ 14.4	11 %
Impairment of equity investments	**$ (4.3)**	$ —	$ (180.6)	**$ 4.3**	*****	$ (180.6)	(100)%
Interest expense, net of capitalized interest	**$ (485.7)**	$ (469.7)	$ (416.8)	**$ 16.0**	**3 %**	$ 52.9	13 %
Net income	**$ 593.5**	$ 743.5	$ 379.2	**$ (150.0)**	**(20)%**	$ 364.3	96 %
Net income attributable to noncontrolling interests	**$ 205.7**	$ 391.5	$ 134.2	**$ (185.8)**	**(47)%**	$ 257.3	*
Net income attributable to ONEOK	**$ 387.8**	$ 352.0	$ 245.0	**$ 35.8**	**10 %**	$ 107.0	44 %
Adjusted EBITDA	**$ 1,986.9**	$ 1,849.9	$ 1,579.5	**$ 137.0**	**7 %**	$ 270.4	17 %
Capital expenditures	**$ 512.4**	$ 624.6	$ 1,188.3	**$ (112.2)**	**(18)%**	$ (563.7)	(47)%

* Percentage change is greater than 100 percent or is not meaningful.
See reconciliation of income from continuing operations to adjusted EBITDA in the “Adjusted EBITDA” section.

Due to the nature of our contracts, changes in commodity prices and sales volumes affect both commodity sales and cost of sales and fuel in our Consolidated Statements of Income and, therefore, the impact is largely offset between the two line items.

2017 vs. 2016 - Operating income and adjusted EBITDA increased primarily as a result of the following:

- Natural gas and NGL volume growth in the Williston Basin and STACK and SCOOP areas in our Natural Gas Gathering and Processing and Natural Gas Liquids segments;
- Restructured contracts resulting in higher fee revenues from increased average fee rates and a lower percentage of proceeds retained from the sale of commodities under our POP with fee contracts in our Natural Gas Gathering and Processing segment;
- Higher optimization and marketing earnings due to higher optimization volumes and wider location price differentials in our Natural Gas Liquids segment; and
- Higher firm demand charge contracted capacity in our Natural Gas Pipelines segment; offset partially by
- Higher labor and employee-related costs associated with benefit plans across all three of our segments, labor costs associated with the growth of operations in our Natural Gas Gathering and Processing segment, routine maintenance projects in our Natural Gas Liquids and Natural Gas Pipelines segments and higher ad valorem taxes in our Natural Gas Liquids segment;
- Merger Transaction costs in 2017 of $30.0 million; and
- Lower net realized natural gas prices and condensate prices in our Natural Gas Gathering and Processing segment.

Operating income was also impacted in 2017 by $16.0 million of noncash impairment charges related to nonstrategic long-lived assets in our Natural Gas Gathering and Processing segment.

Net income was further impacted by a one-time noncash charge through income tax expense of $141.3 million, related to revaluation of our deferred tax balances and a valuation allowance on certain state net operating loss and tax credit carryforwards resulting from the enactment of the Tax Cuts and Jobs Act and $20.0 million of noncash expenses related to our Series E Preferred Stock contribution to the Foundation.

Equity in net earnings from investments increased due primarily to higher firm transportation revenues related to Roadrunner's Phase II capacity, which was placed in service in October 2016. Roadrunner is fully subscribed under long-term firm demand charge contracts.

In 2017, we recorded $4.3 million of noncash impairment charges related to a nonstrategic equity investment in our Natural Gas Gathering and Processing segment.

Net income attributable to noncontrolling interests decreased as a result of the Merger Transaction. Prior to June 30, 2017, we and our subsidiaries owned all of the general partner interest, which included incentive distribution rights, and a portion of the limited partner interest, which together represented a 41.2 percent ownership interest in ONEOK Partners. The earnings of ONEOK Partners that are attributed to its units held by the public prior to the Merger Transaction are reported as "Net income attributable to noncontrolling interest" in our accompanying Consolidated Statements of Income until June 30, 2017.

Capital expenditures decreased due primarily to growth projects placed in service in 2016 in our Natural Gas Gathering and Processing segment.

2016 vs. 2015 - Operating income and adjusted EBITDA increased due primarily as a result of the following:

- Higher natural gas and NGL volumes from our completed capital-growth projects in our Natural Gas Gathering and Processing and Natural Gas Liquids segments and from new plant connections and increased ethane recovery in our Natural Gas Liquids segment;
- Higher fees resulting from contract restructuring in our Natural Gas Gathering and Processing segment; and
- Higher firm demand charge volumes contracted in our Natural Gas Pipelines segment; offset partially by
- Lower net realized NGL and natural gas prices in our Natural Gas Gathering and Processing segment; and
- Higher labor costs associated with the growth of our operations in our Natural Gas Gathering and Processing segment and higher employee-related costs associated with incentive and medical benefit plans in all three of our segments.

Operating income was also impacted by higher depreciation expense due to projects completed in 2016 and 2015 and noncash expenses of a share-based deferred compensation plan due primarily to the increase of ONEOK's share price in 2016.

Equity in net earnings from investments increased due primarily to higher volumes delivered to Overland Pass Pipeline from our Bakken NGL Pipeline and higher firm transportation revenues on Northern Border Pipeline and Roadrunner, offset partially by lower equity earnings from our Powder River Basin equity investments.

Interest expense increased primarily as a result of higher interest costs incurred associated with our $500 million debt issuance in August 2015 and lower capitalized interest due to lower spending on capital-growth projects.

Net income attributable to noncontrolling interests, which reflects primarily the portion of ONEOK Partners that we did not own, increased in 2016, compared with 2015, due primarily to higher earnings at ONEOK Partners, including noncash impairment charges in 2015.

Capital expenditures decreased due to projects placed in service in 2016 and 2015, spending reductions to align with customer needs and lower well connect activities in our Natural Gas Gathering and Processing segment due to a reduction in drilling and completion activity.

Additional information regarding our financial results and operating information is provided in the following discussion for each of our segments.

Natural Gas Gathering and Processing

Growth Projects - Our Natural Gas Gathering and Processing segment is investing in growth projects in NGL-rich areas, including the Bakken Shale and Three Forks formations in the Williston Basin and the STACK and SCOOP areas, that we expect will enable us to meet the needs of crude oil and natural gas producers in those areas. Nearly all of the new natural gas production is from horizontally drilled wells in nonconventional resource areas. These wells tend to produce volumes at higher initial production rates resulting generally in higher initial decline rates than conventional vertical wells; however, the decline rates flatten out over time. These wells are expected to have long productive lives.

In 2017, we announced plans to expand our Canadian Valley natural gas processing facility to 400 MMcf/d from 200 MMcf/d and related gathering infrastructure in the STACK area. This project is expected to be complete by the end of 2018 at a cost of approximately $160 million, excluding capitalized interest, and is supported by long-term primarily fee-based contracts, minimum volume commitments and acreage dedications.

In February 2018, we announced plans to construct the 200 MMcf/d Demicks Lake natural gas processing plant and related infrastructure in the core of the Williston Basin. This project is expected to be complete in the fourth quarter 2019 at a cost of $400 million, excluding capitalized interest, and is supported by long-term primarily fee-based contracts and acreage dedications.

In 2015, 2016 and 2017 we completed the following projects:

Completed Projects	Location	Capacity	Approximate Costs (a)	Completion Date
			(*In millions*)	
Lonesome Creek processing plant and infrastructure	Williston Basin	200 MMcf/d	$600	November 2015
Sage Creek infrastructure	Powder River Basin	Various	$35	December 2015
Natural gas compression	Williston Basin	100 MMcf/d	$75	December 2015
Bear Creek processing plant and infrastructure	Williston Basin	80 MMcf/d	$240	August 2016
Stateline de-ethanizers	Williston Basin	26 MBbl/d	$85	September 2016
Natural gas gathering pipeline and infrastructure	STACK	200 MMcf/d	$40	December 2017

(a) Excludes capitalized interest.

For a discussion of our capital expenditure financing, see “Capital Expenditures” in the “Liquidity and Capital Resources” section.

Selected Financial Results and Operating Information - The following tables set forth certain selected financial results and operating information for our Natural Gas Gathering and Processing segment for the periods indicated.

	Years Ended December 31,			Variances 2017 vs. 2016		Variances 2016 vs. 2015	
Financial Results	**2017**	**2016**	**2015**	**Increase (Decrease)**		**Increase (Decrease)**	
				(*Millions of dollars*)			
NGL sales	**$ 1,208.0**	$ 586.0	$ 554.3	**$ 622.0**	*****	$ 31.7	6 %
Condensate sales	**103.2**	58.3	55.1	**44.9**	**77 %**	3.2	6 %
Residue natural gas sales	**856.3**	690.6	839.5	**165.7**	**24 %**	(148.9)	(18)%
Gathering, compression, dehydration and processing fees and other revenue	**859.1**	716.7	388.2	**142.4**	**20 %**	328.5	85 %
Cost of sales and fuel (exclusive of depreciation and items shown separately below)	**(2,216.4)**	(1,331.5)	(1,265.6)	**884.9**	**66 %**	65.9	5 %
Operating costs	**(309.5)**	(285.6)	(272.4)	**23.9**	**8 %**	13.2	5 %
Equity in net earnings from investments, excluding noncash impairment charges	**12.1**	10.7	17.9	**1.4**	**13 %**	(7.2)	(40)%
Other	**5.7**	1.6	1.6	**4.1**	*****	—	— %
Adjusted EBITDA	**$ 518.5**	$ 446.8	$ 318.6	**$ 71.7**	**16 %**	$ 128.2	40 %
Impairment of equity investments	**$ (4.3)**	$ —	$ (180.6)	**$ 4.3**	*****	$ (180.6)	(100)%
Capital expenditures	**$ 284.2**	$ 410.5	$ 887.9	**$ (126.3)**	**(31)%**	$ (477.4)	(54)%

* Percentage change is greater than 100 percent or is not meaningful.
See reconciliation of income from continuing operations to adjusted EBITDA in the “Adjusted EBITDA” section.

Due to the nature of our contracts, changes in commodity prices and sales volumes affect commodity sales and cost of sales and fuel and, therefore, the impact is largely offset between these line items.

2017 vs. 2016 - Adjusted EBITDA increased $71.7 million, primarily as a result of the following:

- an increase of $66.0 million due primarily to natural gas volume growth in the Williston Basin and the STACK and SCOOP areas, offset partially by natural production declines and the impact of severe winter weather in the first quarter 2017; and
- an increase of $44.0 million due primarily to restructured contracts resulting in higher fee revenues from increased average fee rates, offset partially by a lower percentage of proceeds retained from the sale of commodities under our POP with fee contracts; offset partially by
- an increase of $23.9 million in operating costs due primarily to increased labor and employee-related costs associated with our benefit plans and the growth of our operations;
- a decrease of $11.9 million due primarily to lower realized natural gas and condensate prices; and
- a decrease of $8.0 million due to contract settlements in 2016.

Capital expenditures decreased due to growth projects placed in service in 2016.

See "Capital Expenditures" in "Liquidity and Capital Resources" for additional detail of our projected capital expenditures.

2016 vs. 2015 - Adjusted EBITDA increased $128.2 million, primarily as a result of the following:

- an increase of $144.3 million due primarily to restructured contracts resulting in higher fee revenues from increased average fee rates, offset partially by a lower percentage of proceeds retained from the sale of commodities under our POP with fee contracts;
- an increase of $92.2 million due primarily to natural gas volume growth in the Rocky Mountain region, offset partially by volume declines in the Mid-Continent region and the impact of weather in the Williston Basin in December 2016; and
- an increase of $8.0 million due to contract settlements; offset partially by
- a decrease of $91.9 million due primarily to lower net realized NGL and natural gas prices;
- an increase of $13.2 million in operating costs due primarily to increased labor related to the growth of our operations resulting from completed capital-growth projects and higher employee-related costs associated with incentive and medical benefit plans;
- a decrease of $7.2 million due to lower equity earnings primarily related to our Powder River Basin equity investments; and
- a decrease of $4.0 million due primarily to increased ethane recovery to maintain downstream NGL product specifications.

Capital expenditures decreased due to projects placed in service, spending reductions to align with customer needs and lower well connect activities due to a reduction in drilling and completion activity.

	Years Ended December 31,		
Operating Information (a)	**2017**	**2016**	**2015**
Natural gas gathered (*BBtu/d*)	**2,211**	2,034	1,932
Natural gas processed (*BBtu/d*) (b)	**2,056**	1,882	1,687
NGL sales (*MBbl/d*)	**187**	156	129
Residue natural gas sales (*BBtu/d*)	**896**	865	853
Realized composite NGL net sales price (*$/gallon*) (c) (d)	**$ 0.22**	$ 0.23	$ 0.34
Realized condensate net sales price (*$/Bbl*) (c) (e)	**$ 35.22**	$ 38.31	$ 37.81
Realized residue natural gas net sales price (*$/MMBtu*) (c) (e)	**$ 2.48**	$ 2.80	$ 3.64
Average fee rate (*$MMBtu*)	**$ 0.86**	$ 0.76	$ 0.44

(a) - Includes volumes for consolidated entities only.
(b) - Includes volumes at company-owned and third-party facilities.
(c) - Includes the impact of hedging activities on our equity volumes.
(d) - Net of transportation and fractionation costs.
(e) - Net of transportation costs.

Natural gas gathered, natural gas processed, NGL sales and residue natural gas sales increased in 2017, compared with 2016, due to the completion of growth projects and new supply in the Williston Basin and the STACK and SCOOP areas, offset partially by natural production declines on existing wells and the impact of severe winter weather in the first quarter 2017.

Natural gas gathered, natural gas processed, NGL sales and residue natural gas sales increased in 2016, compared with 2015, due to the completion of capital-growth projects in the Williston Basin, offset partially by natural gas volume declines in the Mid-Continent region.

The quantity and composition of NGLs and natural gas are expected to continue to change with anticipated production increases across our supply basins, new processing plants placed in service and increased ethane recovery.

Commodity Price Risk - See discussion regarding our commodity price risk under "Commodity Price Risk" in Item 7A, Quantitative and Qualitative Disclosures about Market Risk.

Impairment Charges - In the third quarter 2017, following a review of nonstrategic assets for potential divestiture, we recorded $16.0 million of noncash impairment charges related to certain nonstrategic gathering and processing assets located in North Dakota and $4.3 million of noncash impairment charges related to a nonstrategic equity investment located in Oklahoma.

In 2015, due to the continued and greater than expected decline in volumes gathered in the dry natural gas area of the Powder River Basin, we evaluated our investments in this area. We recorded a $63.5 million noncash impairment charge to long-lived assets for our coal-bed methane natural gas gathering system, which we shut down in 2016. We reviewed our Bighorn Gas Gathering, Fort Union Gas Gathering and Lost Creek Gathering Company equity investments and recorded noncash impairment charges of $180.6 million in 2015.

In 2015, we also recorded a noncash impairment charge of $10.2 million related to a previously idled asset, as our expectation for future use of the asset changed.

Natural Gas Liquids

Growth Projects - Our growth strategy in our Natural Gas Liquids segment is focused around the crude oil and NGL-rich natural gas drilling activity in shale and other nonconventional resource areas from the Rocky Mountain region through the Mid-Continent region into the Permian Basin. Crude oil, natural gas and NGL production from this activity; higher petrochemical industry demand for NGL products; and increased exports have resulted in our making additional capital investments to expand our infrastructure to bring these commodities from supply basins to market.

Our Natural Gas Liquids segment invests in NGL-related projects to accommodate the transportation, fractionation and storage of NGL supply from shale and other resource development areas across our asset base and alleviate expected infrastructure constraints between the Mid-Continent and Gulf Coast market centers and to meet increasing petrochemical industry and NGL export demand in the Gulf Coast.

We have the following projects announced or under construction:

Project in Progress	Location	Capacity	Approximate Costs (a)	Completion Date
			(In millions)	
WTLPG pipeline expansion (b)	Permian Basin	110 MBbl/d	$200	Third Quarter 2018
Sterling III pipeline expansion and Arbuckle connection	STACK and SCOOP	60 MBbl/d	$130	Fourth Quarter 2018
Elk Creek pipeline and related infrastructure	Rocky Mountain Region	240 MBbl/d	$1,400	Fourth Quarter 2019
Arbuckle II pipeline and related infrastructure	STACK and SCOOP	400 MBbl/d	$1,360	First Quarter 2020
MB-4 fractionator and related infrastructure	Gulf Coast	125 MBbl/d	$575	First Quarter 2020
Total			$3,665	

(a) Excludes capitalized interest/AFUDC.
(b) A joint venture, in which we own an 80 percent interest. Approximate costs represent total project costs.

In January 2018, we announced plans to construct the new Elk Creek pipeline and related infrastructure to transport NGLs from the Rocky Mountain region, which includes the Williston, DJ and Powder River Basins, to our existing Mid-Continent NGL facilities. The project includes construction of an approximately 900-mile, 20-inch diameter pipeline that is expected to be completed by the end of 2019 and will have the capacity to transport up to 240 MBbl/d of unfractionated NGLs to Bushton, Kansas. The pipeline will have the capability to be expanded to 400 MBbl/d with additional pump facilities. This project is anchored by long-term contracts with terms ranging between 10 to 15 years totaling approximately 100 MBbl/d, which is supported primarily by minimum volume commitments.

In February 2018, we announced plans to construct the new Arbuckle II pipeline and related infrastructure project, with initial capacity to transport 400 MBbl/d of NGLs originating across our supply basins to our storage and fractionation facilities in Mont Belvieu, Texas. The approximately 530-mile pipeline is expandable to 1,000 MBbl/d with additional pump facilities. This project is anchored by long-term contracts with terms ranging from 10 to 20 years and is more than 50 percent contracted.

In February 2018, we announced plans to construct the new MB-4 fractionation facility and related infrastructure, which includes additional NGL storage capacity in Mont Belvieu, Texas. Our current available fractionation capacity in the Gulf Coast region is not sufficient for the expected increase in NGL volumes from supply growth and our pipeline projects discussed above. The fractionator will have a capacity of 125 MBbl/d, is anchored by long-term contracts with terms ranging from 10 to 20 years and is fully contracted.

In 2015 and 2016 we completed the following projects:

Completed Projects	Location	Capacity	Approximate Costs (a)	Completion Date
			(In millions)	
NGL Pipeline and Hutchinson Fractionator infrastructure	Mid-Continent Region	95 miles	$120	April 2015
Bear Creek NGL infrastructure	Williston Basin	40 miles	$45	August 2016

(a) Excludes capitalized interest/AFUDC.

We continue to evaluate opportunities to increase the capacity of our gathering and fractionation assets or construct new assets to connect supply growth from the Williston Basin, Mid-Continent and Permian Basin with end-use markets. The Elk Creek pipeline project replaces our previously announced expansion of the Bakken NGL Pipeline.

In 2017, we connected one third-party natural gas processing plant to our NGL system in the Rocky Mountain region, two in the Permian Basin and three in the STACK and SCOOP areas of the Mid-Continent region.

For a discussion of our capital expenditure financing, see “Capital Expenditures” in the “Liquidity and Capital Resources” section.

Selected Financial Results and Operating Information - The following tables set forth certain selected financial results and operating information for our Natural Gas Liquids segment for the periods indicated.

	Years Ended December 31,			Variances 2017 vs. 2016		Variances 2016 vs. 2015	
Financial Results	**2017**	**2016**	**2015**	**Increase (Decrease)**		**Increase (Decrease)**	
	(Millions of dollars)						
NGL and condensate sales	**$ 8,998.9**	$ 6,152.5	$ 5,200.8	**$ 2,846.4**	**46%**	$ 951.7	18 %
Exchange service revenues	**1,430.3**	1,327.5	1,196.9	**102.8**	**8%**	130.6	11 %
Transportation and storage revenues	**197.0**	195.7	182.0	**1.3**	**1%**	13.7	8 %
Cost of sales and fuel (exclusive of depreciation and items shown separately below)	**(9,176.5)**	(6,321.4)	(5,328.3)	**2,855.1**	**45%**	993.1	19 %
Operating costs	**(359.8)**	(327.6)	(314.5)	**32.2**	**10%**	13.1	4 %
Equity in net earnings from investments	**59.9**	54.5	38.7	**5.4**	**10%**	15.8	41 %
Other	**5.1**	(1.6)	(3.3)	**6.7**	*****	1.7	52 %
Adjusted EBITDA	**$ 1,154.9**	$ 1,079.6	$ 972.3	**$ 75.3**	**7%**	$ 107.3	11 %
Capital expenditures	**$ 114.3**	$ 105.9	$ 226.1	**$ 8.4**	**8%**	$ (120.2)	(53)%

* Percentage change is greater than 100 percent.
See reconciliation of income from continuing operations to adjusted EBITDA in the “Adjusted EBITDA” section.

Due to the nature of our contracts, changes in commodity prices and sales volumes affect commodity sales and cost of sales and fuel, and therefore the impact is largely offset between these line items.

2017 vs. 2016 - Adjusted EBITDA increased $75.3 million, primarily as a result of the following:

- an increase of $81.5 million in exchange services due primarily to increased supply volumes in the Williston Basin, the STACK and SCOOP areas and the Powder River Basin and ethane recovery; offset partially by lower volumes in the Granite Wash and Barnett Shale and reduced volumes related to Hurricane Harvey;
- an increase of $13.5 million in our optimization and marketing activities due primarily to higher optimization volumes and wider location price differentials; and
- an increase of $5.4 million in equity in net earnings from investments due primarily to higher volumes delivered to Overland Pass Pipeline from our Bakken NGL Pipeline and higher volumes and increased ethane recovery from plants connected to Overland Pass Pipeline; offset partially by
- an increase of $32.2 million in operating costs due primarily to routine maintenance projects, higher ad valorem taxes, higher labor and employee-related costs associated with our benefit plans and additional operating costs related to Hurricane Harvey.

Capital expenditures increased due primarily to increased routine growth and maintenance projects.

2016 vs. 2015 - Adjusted EBITDA increased $107.3 million, primarily as a result of the following:

- an increase of $90.0 million in exchange services due to increased exchange services volumes from recently connected natural gas processing plants primarily in the Williston Basin, increased Mid-Continent volumes gathered in the STACK and SCOOP areas and increased volumes resulting from increased ethane recovery primarily from the Williston Basin to maintain downstream NGL product specifications; offset partially by lower volumes and rates on the West Texas LPG system and the impact of weather on our system in December 2016;
- an increase of $15.8 million in equity in net earnings from investments due primarily to higher volumes delivered to Overland Pass Pipeline from our Bakken NGL Pipeline;
- an increase of $13.8 million in transportation and storage services due to higher storage and terminaling revenue in the Gulf Coast and revenues from minimum volume obligations on our distribution pipelines;
- an increase of $8.4 million related to higher isomerization volumes resulting from wider NGL price differentials between normal butane and iso-butane; and
- an increase of $4.3 million due to the impact of operational measurement gains in 2016 and operational measurement losses in 2015; offset partially by
- a decrease of $13.8 million in our optimization and marketing activities, which resulted from a $20.0 million decrease due primarily to narrower product price differentials, offset partially by a $6.2 million increase due primarily to higher optimization volumes; and
- an increase of $13.1 million in operating costs due primarily to higher employee-related costs associated with incentive and medical benefit plans.

Capital expenditures decreased due primarily to spending reductions for growth capital to align with customer needs.

In 2015, we recorded a noncash impairment charge of $10.0 million related to a previously idled asset, as our expectation for future use of the asset changed.

	Years Ended December 31,		
Operating Information	**2017**	**2016**	**2015**
NGLs transported - gathering lines (*MBbl/d*) (a)	**812**	770	769
NGLs fractionated (*MBbl/d*) (b)	**621**	586	552
NGLs transported - distribution lines (*MBbl/d*) (a)	**567**	508	428
Average Conway-to-Mont Belvieu OPIS price differential - ethane in ethane/propane mix (*$/gallon*)	**$ 0.05**	$ 0.03	$ 0.02

(a) - Includes volumes for consolidated entities only.
(b) - Includes volumes at company-owned and third-party facilities.

2017 vs. 2016 - NGLs transported on gathering lines and NGLs fractionated increased due to higher volumes primarily from the STACK and SCOOP areas and Williston Basin resulting from recent plant connections, increased supply and increased ethane recovery, which was offset partially by decreased volumes from the Barnett Shale and Granite Wash. NGLs transported on gathering lines also increased due to higher volumes from the Permian Basin.

While overall NGL supply volumes and ethane recovery increased, a portion of the fees associated with those volumes gathered and fractionated was previously being earned under contracts with minimum volume obligations.

NGLs transported on distribution lines increased due primarily to higher transported volumes for optimization activities.

2016 vs. 2015 - NGLs transported on gathering lines remained relatively unchanged due to increased volumes from new plant connections in the Williston Basin, increased ethane recovery and increased Mid-Continent volumes gathered in the STACK and SCOOP areas, offset by decreased volumes on the West Texas LPG system, decreased Mid-Continent volumes gathered from the Barnett Shale, lower short-term contracted volumes and the impact of weather on gathered volumes across our system in December 2016.

NGLs fractionated increased due to increased volumes from new plant connections in the Williston Basin, increased ethane recovery and increased Mid-Continent volumes gathered in the STACK and SCOOP areas, offset partially by decreased volumes gathered from the Barnett Shale and lower short-term contracted volumes and the impact of weather on gathered volumes across our system in December 2016.

While the volume of ethane recovered increased, a portion of the fees associated with those volumes gathered and fractionated was previously being earned under contracts with minimum volume obligations.

NGLs transported on distribution lines increased due primarily to higher gathered and fractionated volumes as discussed above and due to increased volumes transported for our optimization business.

Natural Gas Pipelines

Growth Projects - The development of shale and other resource areas has continued to increase available natural gas supply, and we expect producers to require incremental transportation services in the future as additional supply is developed. The abundance of natural gas supply and regulations on emissions from coal-fired electric-generation plants may also increase the demand for our services from electric-generation companies if they convert to a natural gas fuel source.

In 2016 we completed the following projects:

Completed Projects	Location	Capacity	Approximate Costs (a)	Completion Date
			(*In millions*)	
WesTex Pipeline Expansion	Permian Basin	260 MMcf/d	$55	October 2016
Roadrunner Gas Transmission Pipeline - Equity-Method Investment				
Phase I (b)	Permian Basin	170 MMcf/d	$200	March 2016
Phase II (b)	Permian Basin	400 MMcf/d	$210	October 2016
Roadrunner Gas Transmission Pipeline Total			$410	

(a) - Excludes capitalized interest.
(b) - 50-50 joint venture equity-method investment. Approximate costs represent total project costs.

The WesTex pipeline expansion is a wholly owned project. Roadrunner is a 50 percent-owned joint venture equity-method investment. Both the WesTex pipeline expansion and Roadrunner are fully subscribed with 25-year firm demand charge, fee-based agreements. Together, these projects provide markets in Mexico access to upstream supply basins in West Texas and the Mid-Continent region.

Selected Financial Results and Operating Information - The following tables set forth certain selected financial results and operating information for our Natural Gas Pipelines segment for the periods indicated:

Financial Results	Years Ended December 31, 2017	2016	2015	Variances 2017 vs. 2016 Increase (Decrease)		Variances 2016 vs. 2015 Increase (Decrease)	
			(*Millions of dollars*)				
Transportation revenues	**$ 323.7**	$ 288.5	$ 258.6	**$ 35.2**	**12 %**	$ 29.9	12 %
Storage revenues	**59.2**	60.0	57.1	**(0.8)**	**(1)%**	2.9	5 %
Natural gas sales and other revenues	**37.0**	30.9	16.7	**6.1**	**20 %**	14.2	85 %
Cost of sales and fuel (exclusive of depreciation and items shown separately below)	**(43.4)**	(30.6)	(34.5)	**12.8**	**42 %**	(3.9)	(11)%
Operating costs	**(126.2)**	(115.6)	(105.7)	**10.6**	**9 %**	9.9	9 %
Equity in net earnings from investments	**87.3**	74.4	68.7	**12.9**	**17 %**	5.7	8 %
Other	**2.2**	5.5	14.1	**(3.3)**	**(60)%**	(8.6)	(61)%
Adjusted EBITDA	**$ 339.8**	$ 313.1	$ 275.0	**$ 26.7**	**9 %**	$ 38.1	14 %
Capital expenditures	**$ 95.6**	$ 96.3	$ 58.2	**$ (0.7)**	**(1)%**	$ 38.1	65 %

See reconciliation of income from continuing operations to adjusted EBITDA in the "Adjusted EBITDA" section.

2017 vs. 2016 - Adjusted EBITDA increased $26.7 million primarily as a result of the following:

- an increase of $26.9 million from higher transportation services due primarily to increased firm demand charge contracted capacity; and
- an increase of $12.9 million in equity in net earnings from investments due primarily to higher firm transportation revenues on Roadrunner; offset partially by
- an increase of $10.6 million in operating costs due primarily to routine maintenance projects and higher labor and employee-related costs associated with our benefit plans; and
- a decrease of $6.3 million due primarily to gains on sales of excess natural gas in storage in 2016.

2016 vs. 2015 - Adjusted EBITDA increased $38.1 million primarily as a result of the following:

- an increase of $28.5 million from higher transportation services due primarily to increased firm demand charge contracted capacity;
- an increase of $9.3 million from higher net retained fuel due to higher throughput and the associated natural gas volumes retained and higher equity gas sales related to transportation and storage services;
- an increase of $6.6 million due to higher natural gas storage services as a result of increased storage rates and increased sales of excess natural gas in storage; and
- an increase of $5.7 million in equity in net earnings from investments due primarily to higher firm transportation revenues on Northern Border Pipeline and Roadrunner; offset partially by
- an increase of $9.9 million in operating costs due primarily to increased employee-related costs associated with incentive and medical benefit plans and higher ad valorem taxes.

Capital expenditures increased due primarily to our WesTex pipeline expansion and other expansion projects.

Operating Information (a)	Years Ended December 31, 2017	2016	2015
Natural gas transportation capacity contracted (*MDth/d*)	**6,611**	6,345	5,840
Transportation capacity subscribed	**94%**	92%	92%
Average natural gas price			
Mid-Continent region (*$/MMBtu*)	**$ 2.64**	$ 2.28	$ 2.42

(a) - Includes volumes for consolidated entities only.

Our natural gas pipelines primarily serve end users, such as natural gas distribution and electric-generation companies, that require natural gas to operate their businesses regardless of location price differentials. Overall, our contracted transportation capacity and fee-based earnings in this segment increased in connection with the October 2016 completion of our WesTex pipeline expansion.

Northern Border Pipeline, in which we have a 50 percent ownership interest, has contracted substantially all of its long-haul transportation capacity through the fourth quarter 2020. We made a contribution of $83 million to Norther Border Pipeline in the third quarter 2017. During the years ended December 31, 2015 and 2016, we made no contributions to Norther Border Pipeline.

Under the terms of settlement with shippers in 2012, Northern Border Pipeline was required to file a rate case by January 1, 2018. In December 2017, Northern Border Pipeline entered into a settlement with shippers that was approved by the FERC in February 2018. The settlement provides for tiered rate reductions beginning January 1, 2018, that will reduce rates 12.5 percent by January 2020 compared with previous rates and requires new rates to be established by January 2024. We do not expect the resulting decrease in equity earnings and cash distributions from Northern Border Pipeline to be material to us.

Roadrunner, in which we have a 50 percent ownership interest, has contracted all of its capacity through 2041. We contributed $4 million, $65 million and $30 million to Roadrunner during the years ended December 31, 2017, 2016 and 2015, respectively.

Adjusted EBITDA

Adjusted EBITDA is a non-GAAP measure of our financial performance. Adjusted EBITDA is defined as net income adjusted for interest expense, depreciation and amortization, noncash impairment charges, income taxes, allowance for equity funds used during construction, noncash compensation and other noncash items. Prior periods have been adjusted to conform to current presentation. We believe this non-GAAP financial measure is useful to investors because it and similar measures are used by many companies in our industry as a measurement of financial performance and is commonly employed by financial analysts and others to evaluate our financial performance and to compare financial performance among companies in our industry. Adjusted EBITDA should not be considered an alternative to net income, earnings per unit or any other measure of financial performance presented in accordance with GAAP. Additionally, this calculation may not be comparable with similarly titled measures of other companies.

A reconciliation of income from continuing operations, the nearest comparable GAAP financial performance measure, to adjusted EBITDA for the years ended December 31, 2017, 2016 and 2015, is as follows:

	Years Ended December 31,		
(*Unaudited*)	**2017**	**2016**	**2015**
Reconciliation of income from continuing operations to adjusted EBITDA	(*Thousands of dollars*)		
Income from continuing operations	**$ 593,519**	$ 745,550	$ 385,276
Add:			
Interest expense, net of capitalized interest	**485,658**	469,651	416,787
Depreciation and amortization	**406,335**	391,585	354,620
Income taxes	**447,282**	212,406	136,600
Impairment charges	**20,240**	—	264,256
Noncash compensation expense	**13,421**	31,981	13,799
Other noncash items and equity AFUDC (a)	**20,398**	(1,255)	8,126
Adjusted EBITDA	**$ 1,986,853**	$ 1,849,918	$ 1,579,464
Reconciliation of segment adjusted EBITDA to adjusted EBITDA			
Segment adjusted EBITDA:			
Natural Gas Gathering and Processing	**$ 518,472**	$ 446,778	$ 318,554
Natural Gas Liquids	**1,154,939**	1,079,619	972,292
Natural Gas Pipelines	**339,818**	313,137	274,980
Other (b)	**(26,376)**	10,384	13,638
Adjusted EBITDA	**$ 1,986,853**	$ 1,849,918	$ 1,579,464

(a) - Year ended December 31, 2017, includes our April 2017 contribution to the Foundation of 20,000 shares of Series E Preferred Stock, with an aggregate value of $20.0 million.
(b) - Year ended December 31, 2017, includes Merger Transaction costs of $30.0 million.

CONTINGENCIES

See Note O of the Notes to Consolidated Financial Statements in this Annual Report for a discussion of developments concerning the Gas Index Pricing Litigation.

Other Legal Proceedings - We are a party to various litigation matters and claims that have arisen in the normal course of our operations. While the results of these litigation matters and claims cannot be predicted with certainty, we believe the reasonably possible losses from such matters, individually and in the aggregate, are not material. Additionally, we believe the probable final outcome of such matters will not have a material adverse effect on our consolidated results of operations, financial position or cash flows.

LIQUIDITY AND CAPITAL RESOURCES

General - Historically, our primary source of cash inflows were distributions to us from our general partner and limited partner interests in ONEOK Partners. Beginning in the third quarter 2017, as a result of the completion of the Merger Transaction, our cash flow sources and requirements significantly changed. We now rely primarily on operating cash flows, commercial paper, bank credit facilities, debt issuances and the issuance of common stock for our liquidity and capital resources requirements. In addition, we expect increased cash outflows related to i) capital expenditures, which were previously funded by ONEOK Partners and ii) dividends paid to shareholders, due to the increase in the number of shares outstanding as a result of the close of the Merger Transaction, our recent equity issuances and higher anticipated dividends per share, subject to board of directors' approval. We expect to pay no significant cash income taxes through 2021.

We expect our sources of cash inflow to provide sufficient resources to finance our operations, capital expenditures and quarterly cash dividends, including expected future dividend increases. To the extent operating cash flows are not sufficient to fund our dividends, we may utilize short- and long-term debt and issuances of equity, as necessary or appropriate. We may access the capital markets to issue debt or equity securities as we consider prudent to provide liquidity to refinance existing debt, improve credit metrics or to fund capital expenditures. However, with $1.6 billion of equity issued in 2017 and January 2018, we have satisfied our expected equity financing needs through 2018 and well into 2019. We expect to fund growth projects with cash from operations, short-term borrowings and long-term debt.

We manage interest-rate risk through the use of fixed-rate debt, floating-rate debt and interest-rate swaps. For additional information on our interest rate swaps, see Note D of the Notes to Consolidated Financial Statements in this Annual Report.

Cash Management - We use a centralized cash management program that concentrates the cash assets of our operating subsidiaries in joint accounts for the purposes of providing financial flexibility and lowering the cost of borrowing, transaction costs and bank fees. Our centralized cash management program provides that funds in excess of the daily needs of our operating subsidiaries are concentrated, consolidated or otherwise made available for use by other entities within our consolidated group. Our operating subsidiaries participate in this program to the extent they are permitted pursuant to FERC regulations or their operating agreements. Under the cash management program, depending on whether a participating subsidiary has short-term cash surpluses or cash requirements, we provide cash to the subsidiary or the subsidiary provides cash to us.

Short-term Liquidity - Our principal sources of short-term liquidity consist of cash generated from operating activities, distributions received from our equity-method investments, proceeds from our commercial paper program and our $2.5 Billion Credit Agreement.

In April 2017, we entered into the $2.5 Billion Credit Agreement with a syndicate of banks to replace the ONEOK Credit Agreement and the ONEOK Partners Credit Agreement. The $2.5 Billion Credit Agreement became effective June 30, 2017, upon the closing of the Merger Transaction (as described in Note B of the Notes to Consolidated Financial Statements in this Annual Report) and the terminations of the ONEOK Credit Agreement and the ONEOK Partners Credit Agreement. As of December 31, 2017, we were in compliance with all covenants of the $2.5 Billion Credit Agreement.

In July 2017, the commercial paper outstanding under the ONEOK Partners commercial paper program was repaid as it matured with a combination of proceeds from new issuances from ONEOK's recently established $2.5 billion commercial paper program, cash on hand and proceeds from our July 2017 $1.2 billion senior notes issuance. The $2.4 billion ONEOK Partners commercial paper program was terminated in July 2017.

At December 31, 2017, we had $37.2 million of cash and cash equivalents and $1.9 billion of borrowing capacity under the $2.5 Billion Credit Agreement. Following the January 2018 equity offering, we had $2.5 billion of borrowing capacity.

We had working capital (defined as current assets less current liabilities) deficits of $0.9 billion and $1.4 billion as of December 31, 2017, and December 31, 2016, respectively. Although working capital is influenced by several factors, including, among other things: (i) the timing of (a) scheduled debt payments, (b) the collection and payment of accounts receivable and payable, and (c) equity and debt issuances, and (ii) the volume and cost of inventory and commodity imbalances, our working capital deficit at December 31, 2017, and at December 31, 2016, was driven primarily by current maturities of long-term debt and short-term borrowings. We may have working capital deficits in future periods as we continue to finance our capital-growth projects and repay long-term debt, often initially with short-term borrowings. Our decision to utilize short-term borrowings rather than long-term debt, due to more favorable interest rates, contributes to our working capital deficit. We do not expect this working capital deficit to have an adverse impact to our cash flows or operations.

For additional information on our $2.5 Billion Credit Agreement and commercial paper program, see Note G of the Notes to Consolidated Financial Statements in this Annual Report.

Long-term Financing - In addition to our principal sources of short-term liquidity discussed above, we expect to fund our longer-term financing requirements by issuing long-term notes. Other options to obtain financing include, but are not limited to, issuing common stock, loans from financial institutions, issuance of convertible debt securities or preferred equity securities, asset securitization and the sale and lease-back of facilities.

Debt issuances and upcoming maturities - In July 2017, we completed an underwritten public offering of $1.2 billion senior unsecured notes consisting of $500 million, 4.0 percent senior notes due 2027, and $700 million, 4.95 percent senior notes due 2047. The net proceeds, after deducting underwriting discounts, commissions and offering expenses, were $1.2 billion. The proceeds were used for general corporate purposes, which included repayment of existing indebtedness and capital expenditures.

We expect to repay ONEOK Partners' $425 million, 3.2 percent senior notes due in September 2018, with a combination of cash on hand and short-term borrowings.

Repayments - We repaid $500 million in both January 2018 and July 2017 on the Term Loan Agreement due 2019 with a combination of cash on hand and short-term borrowings. As of January 2018, all amounts outstanding under the Term Loan Agreement have been repaid.

In 2017, we repaid ONEOK Partners' $400 million, 2.0 percent senior notes due in October 2017 with a combination of cash on hand and short-term borrowings and redeemed our 6.5 percent senior notes due 2028 at a redemption price of $87.0 million with cash on hand.

For additional information on our long-term debt, see Note G of the Notes to Consolidated Financial Statements in this Annual Report.

Equity issuances - In January 2018, we completed an underwritten public offering of 21.9 million shares of our common stock at a public offering price of $54.50 per share, generating net proceeds of $1.2 billion. We used the net proceeds from this offering to fund capital expenditures and for general corporate purposes, which included repaying a portion of our outstanding indebtedness.

In July 2017, we established an "at-the-market" equity program for the offer and sale from time to time of our common stock up to an aggregate amount of $1 billion. The program allows us to offer and sell our common stock at prices we deem appropriate through a sales agent. Sales of our common stock may be made by means of ordinary brokers' transactions on the NYSE, in block transactions, or as otherwise agreed to between us and the sales agent. We are under no obligation to offer and sell common stock under the program.

During the year ended December 31, 2017, we sold 8.4 million shares of common stock through our "at-the-market" equity program that resulted in net proceeds of $448.3 million. The net proceeds from these issuances were used for general corporate purposes, including repayment of outstanding indebtedness and to fund capital expenditures. We have satisfied our expected equity financing needs through 2018 and well into 2019.

In April 2017, through a wholly owned subsidiary, we contributed 20,000 shares of Series E Preferred Stock, having an aggregate value of $20.0 million, to the Foundation for use in future charitable and nonprofit causes. The contribution was recorded as a $20.0 million noncash expense in 2017.

Capital Expenditures - The following table sets forth our growth and maintenance capital expenditures, excluding AFUDC and capitalized interest, for the periods indicated:

Capital Expenditures	**2017**	**2016**	**2015**
		(Millions of dollars)	
Natural Gas Gathering and Processing	**$ 284.2**	$ 410.5	$ 887.9
Natural Gas Liquids	**114.3**	105.9	226.1
Natural Gas Pipelines	**95.6**	96.3	58.2
Other	**18.3**	11.9	16.1
Total capital expenditures	**$ 512.4**	$ 624.6	$ 1,188.3

Capital expenditures decreased in 2017 compared with 2016, due primarily to the completion of several large projects. Capital expenditures decreased in 2016 compared with 2015 due to the completion of several large projects and reduced capital spending to align with the needs of our crude oil and natural gas producers.

We classify expenditures that are expected to generate additional revenue, return on investment or significant operating efficiencies as capital-growth expenditures. Maintenance capital expenditures are those capital expenditures required to maintain our existing assets and operations and do not generate additional revenues. Maintenance capital expenditures are made to replace partially or fully depreciated assets, to maintain the existing operating capacity of our assets and to extend their useful lives. Our capital expenditures are financed typically through operating cash flows, short- and long-term debt and the issuance of equity.

The following table summarizes our 2018 projected growth and maintenance capital expenditures, excluding AFUDC and capitalized interest:

2018 Projected Capital Expenditures

	(Millions of dollars)
Growth	$1,950-$2,300
Maintenance	$140-$180
Total projected capital expenditures	$2,090-$2,480

Our projected capital expenditures for 2018 has increased compared with 2017, due primarily to our announced capital-growth projects.

Credit Ratings - Our long-term debt credit ratings as of February 22, 2018, are shown in the table below:

Rating Agency	**Rating**	**Outlook**
Moody's	Baa3	Stable
S&P	BBB	Stable

Following the close of the Merger Transaction, S&P and Moody's upgraded our credit ratings, removed our credit rating from review and issued stable outlooks. Our commercial paper program is rated Prime-3 by Moody's and A-2 by S&P.

Our credit ratings, which are investment grade, may be affected by a material change in our financial ratios or a material event affecting our business and industry. The most common criteria for assessment of our credit ratings are the debt-to-EBITDA ratio, interest coverage, business risk profile and liquidity. If our credit ratings were downgraded, our cost to borrow funds under the $2.5 Billion Credit Agreement would increase and a potential loss of access to the commercial paper market could occur. In the event that we are unable to borrow funds under our commercial paper program and there has not been a material adverse change in our business, we would continue to have access to our $2.5 Billion Credit Agreement, which expires in 2022. An adverse credit rating change alone is not a default under our $2.5 Billion Credit Agreement. We do not expect a downgrade in our credit rating to have a material impact on our results of operations.

In the normal course of business, our counterparties provide us with secured and unsecured credit. In the event of a downgrade in our credit ratings or a significant change in our counterparties' evaluation of our creditworthiness, we could be required to provide additional collateral in the form of cash, letters of credit or other negotiable instruments as a condition of continuing to conduct business with such counterparties. We may be required to fund margin requirements with our counterparties with cash, letters of credit or other negotiable instruments.

Dividends - Holders of our common stock share equally in any dividend declared by our board of directors, subject to the rights of the holders of outstanding preferred stock. In 2017, we paid dividends of $2.72 per share, an increase of 11 percent compared with the prior year. In February 2018, we paid a quarterly dividend of $0.77 per share ($3.08 per share on an annualized basis), an increase of 25 percent compared with the same period in the prior year. Our dividend growth is due to the increase in cash flows resulting from the Merger Transaction and the continued growth of our operations.

Our Series E Preferred Stock pays quarterly dividends on each share of Series E Preferred Stock, when, as and if declared by our Board of Directors, at a rate of 5.5 percent per year. In 2017, we paid dividends of $0.6 million for the Series E Preferred Stock. In February 2018, we paid dividends totaling $0.3 million for the Series E Preferred Stock.

In 2018, we expect our cash flows from operations to continue to sufficiently fund our cash dividends. For the years ended December 31, 2017 and 2016, cash dividends and distributions paid to noncontrolling interests were sufficiently funded by cash flows from operations.

Cash Distributions - Prior to the consummation of the Merger Transaction, we received distributions from ONEOK Partners on our common and Class B units and our 2 percent general partner interest, which included our incentive distribution rights. Distributions paid to ONEOK Partners unitholders of record at the close of business on January 30, 2017, and May 1, 2017, were $0.79 per unit. Our incentive distribution rights effectively terminated at the close of the Merger Transaction.

CASH FLOW ANALYSIS

We use the indirect method to prepare our Consolidated Statements of Cash Flows. Under this method, we reconcile net income to cash flows provided by operating activities by adjusting net income for those items that affect net income but do not result in actual cash receipts or payments during the period and for operating cash items that do not impact net income. These reconciling items include depreciation and amortization, impairment charges, allowance for equity funds used during construction, gain or loss on sale of assets, deferred income taxes, net undistributed earnings from equity-method investments, share-based compensation expense, pension and postretirement benefit expense net of contributions, noncash expense related to our Series E Preferred Stock contribution to the Foundation, other amounts and changes in our assets and liabilities not classified as investing or financing activities.

The following table sets forth the changes in cash flows by operating, investing and financing activities for the periods indicated:

	Years Ended December 31,		
	2017	**2016**	**2015**
		(Millions of dollars)	
Total cash provided by (used in):			
Operating activities	**$ 1,315.4**	$ 1,353.3	$ 1,022.8
Investing activities	**(567.6)**	(615.4)	(1,190.7)
Financing activities	**(959.5)**	(586.5)	92.7
Change in cash and cash equivalents	**(211.7)**	151.4	(75.2)
Change in cash and cash equivalents included in discontinued operations	**—**	(0.1)	—
Change in cash and cash equivalents from continuing operations	**(211.7)**	151.3	(75.2)
Cash and cash equivalents at beginning of period	**248.9**	97.6	172.8
Cash and cash equivalents at end of period	**$ 37.2**	$ 248.9	$ 97.6

Operating Cash Flows - Operating cash flows are affected by earnings from our business activities and changes in our operating assets and liabilities. Changes in commodity prices and demand for our services or products, whether because of general economic conditions, changes in supply, changes in demand for the end products that are made with our products or increased competition from other service providers, could affect our earnings and operating cash flows.

2017 vs. 2016 - Cash flows from operating activities, before changes in operating assets and liabilities, increased to $1.5 billion for 2017, compared with $1.4 billion for 2016. This increase is due primarily to higher revenues resulting from volume growth in the Williston Basin and STACK and SCOOP areas in our Natural Gas Gathering and Processing and Natural Gas Liquids segments, higher fees resulting from contract restructuring in our Natural Gas Gathering and Processing segment, higher transportation services due to increased firm demand charge contracted capacity in our Natural Gas Pipelines segment and higher optimization and marketing earnings due primarily to higher optimization volumes and wider location price differentials in our Natural Gas Liquids segment, as discussed in “Financial Results and Operating Information.”

The changes in operating assets and liabilities decreased operating cash flows $192.6 million for 2017, compared with a decrease of $40.7 million for 2016. This change is due primarily to the change in natural gas and NGLs in storage, which varies from period to period and varies with changes in commodity prices, the change in accounts receivable, accounts payable, and other accruals and deferrals resulting from the timing of receipt of cash from customers and payments to vendors, suppliers and other third parties and the change in risk-management assets and liabilities.

2016 vs. 2015 - Cash flows from operating activities, before changes in operating assets and liabilities, were $1.4 billion for 2016, compared with $1.2 billion for 2015. The increase was due primarily to higher natural gas and NGL volumes from our completed capital-growth projects in our Natural Gas Gathering and Processing and Natural Gas Liquids segments, new plant connections and increased ethane recovery in our Natural Gas Liquids segment and higher fees resulting from contract restructuring in our Natural Gas Gathering and Processing segment, offset partially by lower realized commodity prices, as discussed in "Financial Results and Operating Information." Distributions received from unconsolidated affiliates also increased, due primarily to Overland Pass Pipeline.

The changes in operating assets and liabilities decreased operating cash flows $40.7 million for 2016, compared with a decrease of $133.1 million for 2015. This change is due primarily to the change in accounts receivable, accounts payable, and other accruals and deferrals resulting from the timing of receipt of cash from customers and payments to vendors and suppliers, which vary from period to period and vary with changes in commodity prices, and the change in commodity imbalances, offset partially by the change in risk-management assets and liabilities related to interest-rate swaps.

Investing Cash Flows

2017 vs. 2016 - Cash used in investing activities decreased $47.8 million due primarily to projects placed in service in 2016, offset partially by lower distributions received from unconsolidated affiliates in excess of cumulative earnings, lower proceeds from sale of assets and higher contributions to our unconsolidated affiliates.

2016 vs. 2015 - Cash used in investing activities decreased $575.3 million due primarily to lower capital spending as a result of spending reductions to align with customer needs and projects placed in service, higher proceeds received from sale of assets and higher distributions received from Northern Border Pipeline and Overland Pass Pipeline, offset partially by higher contributions made to Roadrunner.

Financing Cash Flows

2017 vs. 2016 - Cash used in financing activities increased $373.0 million due primarily to repayment of short-term borrowings and increased dividends, offset partially by the issuance of common stock through our "at-the-market" equity program and decreased distributions to noncontrolling interests resulting from the Merger Transaction.

2016 vs. 2015 - Cash used in financing activities was $586.5 million in 2016, compared with cash provided by financing activities of $92.7 million in 2015, a decrease of $679.2 million, due primarily to repayment of $1.1 billion of senior notes, $100 million increase in distributions paid due to a higher number of units outstanding and no equity issuances in 2016. These differences were offset partially by an increase in proceeds from short-term borrowings and drawing on our Term Loan Agreement.

IMPACT OF NEW ACCOUNTING STANDARDS

Information about the impact of new accounting standards is included in Note A of the Notes to Consolidated Financial Statements in this Annual Report.

ESTIMATES AND CRITICAL ACCOUNTING POLICIES

The preparation of our Consolidated Financial Statements and related disclosures in accordance with GAAP requires us to make estimates and assumptions with respect to values or conditions that cannot be known with certainty that affect the reported amounts of assets and liabilities, and the disclosure of contingent assets and liabilities at the date of the Consolidated Financial Statements. These estimates and assumptions also affect the reported amounts of revenue and expenses during the reporting period. Although we believe these estimates and assumptions are reasonable, actual results could differ from our estimates.

The following is a summary of our most critical accounting policies, which are defined as those estimates and policies most important to the portrayal of our financial condition and results of operations and requiring management's most difficult, subjective or complex judgment, particularly because of the need to make estimates concerning the impact of inherently uncertain matters. We have discussed the development and selection of our estimates and critical accounting policies with the Audit Committee of our Board of Directors.

Derivatives and Risk-Management Activities - We utilize derivatives to reduce our market-risk exposure to commodity price and interest-rate fluctuations and to achieve more predictable cash flows. The accounting for changes in the fair value of a derivative instrument depends on whether it qualifies and has been designated as part of a hedging relationship. When possible, we implement effective hedging strategies using derivative financial instruments that qualify as hedges for accounting purposes. We have not used derivative instruments for trading purposes.

For a derivative designated as a cash flow hedge, the effective portion of the gain or loss from a change in fair value of the derivative instrument is deferred in accumulated other comprehensive income (loss) until the forecasted transaction affects earnings, at which time the fair value of the derivative instrument is reclassified into earnings. The ineffective portion of the gain or loss on a derivative instrument designated as a cash flow hedge is recognized in earnings.

We assess the effectiveness of hedging relationships quarterly by performing an effectiveness test on our hedging relationships to determine whether they are highly effective on a retrospective and prospective basis. We do not believe that changes in our fair value estimates of our derivative instruments have a material impact on our results of operations, as the majority of our derivatives are accounted for as cash flow hedges for which ineffectiveness is not material. However, if a derivative instrument is ineligible for cash flow hedge accounting or if we fail to appropriately designate it as a cash flow hedge, changes in fair value of the derivative instrument would be recorded currently in earnings. Additionally, if a cash flow hedge ceases to qualify for hedge accounting treatment because it is no longer probable that the forecasted transaction will occur, the change in fair value of the derivative instrument would be recognized in earnings. For more information on commodity price sensitivity and a discussion of the market risk of pricing changes, see Item 7A, Quantitative and Qualitative Disclosures about Market Risk.

See Notes C and D of the Notes to Consolidated Financial Statements in this Annual Report for additional discussion of fair value measurements and derivatives and risk-management activities.

Impairment of Goodwill and Long-Lived Assets, including Intangible Assets - We assess our goodwill for impairment at least annually on July 1, unless events or changes in circumstances indicate an impairment may have occurred before that time. Our qualitative goodwill impairment analysis performed as of July 1, 2017, did not result in an impairment charge nor did our analysis reflect any reporting units at risk, and subsequent to that date, no event has occurred indicating that the implied fair value of each of our reporting units is less than the carrying value of its net assets.

As part of our goodwill impairment test, we may first assess qualitative factors (including macroeconomic conditions, industry and market considerations, cost factors and overall financial performance) to determine whether it is more likely than not that the fair value of each of our reporting units is less than its carrying amount. If further testing is necessary or a quantitative test is elected, we perform a two-step impairment test for goodwill. In the first step, an initial assessment is made by comparing the fair value of a reporting unit with its book value, including goodwill. If the fair value is less than the book value, an impairment is indicated, and we must perform a second test to measure the amount of the impairment. In the second test, we calculate the implied fair value of the goodwill by deducting the fair value of all tangible and intangible net assets of the reporting unit from the fair value determined in step one of the assessment. If the carrying value of the goodwill exceeds the implied fair value of the goodwill, we will record an impairment charge.

To estimate the fair value of our reporting units, we use two generally accepted valuation approaches, an income approach and a market approach, using assumptions consistent with a market participant's perspective. Under the income approach, we use anticipated cash flows over a period of years plus a terminal value and discount these amounts to their present value using appropriate discount rates. Under the market approach, we apply EBITDA multiples to forecasted EBITDA. The multiples used are consistent with historical asset transactions. The forecasted cash flows are based on average forecasted cash flows for a reporting unit over a period of years.

The following table sets forth our goodwill, by segment, for the periods indicated:

	December 31, 2017	December 31, 2016
	(*Thousands of dollars*)	
Natural Gas Gathering and Processing	**$ 153,404**	$ 122,291
Natural Gas Liquids	**371,217**	268,544
Natural Gas Pipelines	**156,479**	134,700
Total goodwill	**$ 681,100**	$ 525,535

As a result of the Merger Transaction, we are entitled to receive all available ONEOK Partners cash. Our incentive distribution rights effectively terminated at the close of the Merger Transaction. As a result, the $155.6 million carrying value of the indefinite-lived intangible asset associated with our incentive distribution rights was reclassified to goodwill at the close of the Merger Transaction and allocated among our business segments.

We assess our long-lived assets, including intangible assets with finite useful lives, for impairment whenever events or changes in circumstances indicate that an asset's carrying amount may not be recoverable. An impairment is indicated if the carrying amount of a long-lived asset exceeds the sum of the undiscounted future cash flows expected to result from the use and eventual disposition of the asset. If an impairment is indicated, we record an impairment loss equal to the difference between the carrying value and the fair value of the long-lived asset.

For the investments we account for under the equity method, the impairment test considers whether the fair value of the equity investment as a whole, not the underlying net assets, has declined and whether that decline is other than temporary. Therefore, we periodically evaluate the amount at which we carry our equity-method investments to determine whether current events or circumstances warrant adjustments to our carrying value.

Impairment Charges - We recorded $20.2 million of noncash impairment charges in 2017 related to our nonstrategic long-lived assets and equity investments in North Dakota and Oklahoma, and $264.3 million of noncash impairment charges in 2015 primarily related to our long-lived assets and equity investments in the dry natural gas area of the Powder River Basin.

Our impairment tests require the use of assumptions and estimates such as industry economic factors and the profitability of future business strategies. If actual results are not consistent with our assumptions and estimates or our assumptions and estimates change due to new information, we may be exposed to future impairment charges.

See Notes A, E, F and N of the Notes to Consolidated Financial Statements in this Annual Report for additional discussion of goodwill, long-lived assets and investments in unconsolidated affiliates.

Retirement and Postretirement Employee Benefits - We have defined benefit retirement plans covering certain employees and former employees. Our defined benefit pension plan covers certain employees and former employees hired before January 1, 2005, and our supplemental executive retirement plan for the benefit of certain officers closed to new participants in January 2014. We sponsor welfare plans that provide postretirement medical and life insurance benefits to certain employees hired prior to 2017 who retire with at least five years of service. The expense and liability related to these plans is calculated using statistical and other factors that attempt to anticipate future events. These factors include assumptions about the discount rate, expected return on plan assets, rate of future compensation increases, mortality and employment length. In determining the projected benefit obligations and costs, assumptions can change from period to period and may result in material changes in the costs and liabilities we recognize.

During 2017, we recorded net periodic benefit costs of $18.4 million related to our defined benefit pension and postretirement benefits plans. We estimate that in 2018, we will record net periodic benefit costs of $18.1 million related to our defined benefit pension and postretirement benefits plans. Sensitivities to changes with respect to the weighted-average assumptions used to determine our estimated 2018 net periodic benefit obligations are not material.

See Note L of the Notes to Consolidated Financial Statements in this Annual Report for additional information.

Contingencies - Our accounting for contingencies covers a variety of business activities, including contingencies for legal and environmental exposures. We accrue these contingencies when our assessments indicate that it is probable that a liability has been incurred or an asset will not be recovered, and an amount can be reasonably estimated. We expense legal fees as incurred and base our legal liability estimates on currently available facts and our assessments of the ultimate outcome or resolution.

Accruals for estimated losses from environmental remediation obligations generally are recognized no later than the completion of a remediation feasibility study. Recoveries of environmental remediation costs from other parties are recorded as assets when their receipt is deemed probable. Our expenditures for environmental evaluation, mitigation, remediation and compliance to date have not been significant in relation to our financial position or results of operations, and our expenditures related to environmental matters had no material effect on earnings or cash flows during 2017, 2016 or 2015. Actual results may differ from our estimates resulting in an impact, positive or negative, on our results of operations.

See Note O of the Notes to Consolidated Financial Statements in this Annual Report for additional discussion of contingencies.

CONTRACTUAL OBLIGATIONS AND COMMERCIAL COMMITMENTS

The following table sets forth our contractual obligations related to debt, operating leases and other long-term obligations as of December 31, 2017. For additional discussion of the debt agreements, see Note G of the Notes to Consolidated Financial Statements in this Annual Report.

	Payments Due by Period						
Contractual Obligations	**Total**	**2018**	**2019**	**2020**	**2021**	**2022**	**Thereafter**
				(*Millions of dollars*)			
Senior notes	$ 8,047.4	$ 425.0	$ 500.0	$ 300.0	$ —	$ 1,447.4	$ 5,375.0
Commercial paper borrowings (a)	614.7	614.7	—	—	—	—	—
Term Loan Agreement (a)	500.0	—	500.0	—	—	—	—
Guardian Pipeline senior notes	36.6	7.7	7.7	7.7	7.7	5.8	—
Interest payments on debt	5,690.0	449.1	388.6	378.9	368.8	339.4	3,765.2
Operating leases	16.6	2.7	2.1	1.9	1.6	1.4	6.9
Firm transportation and storage contracts	179.0	46.1	37.6	37.3	23.0	14.2	20.8
Financial and physical derivatives	372.6	349.6	23.0	—	—	—	—
Purchase commitments, rights of way and other	176.3	80.8	34.5	34.5	16.3	2.9	7.3
Employee benefit plans	42.4	14.3	9.9	—	8.8	9.4	—
Total	$ 15,675.6	$ 1,990.0	$ 1,503.4	$ 760.3	$ 426.2	$ 1,820.5	$ 9,175.2

(a) - The remaining balance at December 31, 2017, was repaid in January 2018.

Senior notes, Term Loan Agreement and commercial paper borrowings - The amount of principal due in each period.

Interest payments on debt - Interest payments are calculated by multiplying long-term debt principal amount by the respective coupon rates.

Operating leases - Our operating leases include leases for office space and pipeline equipment.

Firm transportation and storage contracts - Our Natural Gas Gathering and Processing and Natural Gas Liquids segments are party to fixed-price contracts for firm transportation and storage capacity.

Financial and physical derivatives - These are obligations arising from our fixed- and variable-price purchase commitments for physical and financial commodity derivatives. Estimated future variable-price purchase commitments are based on market information at December 31, 2017. Actual future variable-price purchase obligations may vary depending on market prices at the time of delivery. Sales of the related physical volumes and net positive settlements of financial derivatives are not reflected in the table above.

Employee benefit plans - We contributed $12.3 million to our defined benefit pension plan in January 2018 and expect to make approximately $2.0 million in contributions to our postretirement plans in 2018. See Note L of the Notes to Consolidated Financial Statements in this Annual Report for discussion of our employee benefit plans.

Purchase commitments, rights of way and other - Purchase commitments include commitments related to our growth capital expenditures and other rights-of-way and contractual commitments. Purchase commitments exclude commodity purchase contracts, which are included in the "Financial and physical derivatives" amounts.

FORWARD-LOOKING STATEMENTS

Some of the statements contained and incorporated in this Annual Report are forward-looking statements as defined under federal securities laws. The forward-looking statements relate to our anticipated financial performance (including projected operating income, net income, capital expenditures, cash flows and projected levels of dividends), liquidity, management's plans and objectives for our future growth projects and other future operations (including plans to construct additional natural gas and natural gas liquids pipelines and processing facilities and related cost estimates), our business prospects, the outcome of regulatory and legal proceedings, market conditions and other matters. We make these forward-looking statements in reliance on the safe harbor protections provided under federal securities legislation and other applicable laws. The following discussion is intended to identify important factors that could cause future outcomes to differ materially from those set forth in the forward-looking statements.

Forward-looking statements include the items identified in the preceding paragraph, the information concerning possible or assumed future results of our operations and other statements contained or incorporated in this Annual Report identified by words such as "anticipate," "estimate," "expect," "project," "intend," "plan," "believe," "should," "goal," "forecast," "guidance," "could," "may," "continue," "might," "potential," "scheduled" and other words and terms of similar meaning.

One should not place undue reliance on forward-looking statements. Known and unknown risks, uncertainties and other factors may cause our actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by forward-looking statements. Those factors may affect our operations, markets, products, services and prices. In addition to any assumptions and other factors referred to specifically in connection with the forward-looking statements, factors that could cause our actual results to differ materially from those contemplated in any forward-looking statement include, among others, the following:

- the effects of weather and other natural phenomena, including climate change, on our operations, demand for our services and energy prices;
- competition from other United States and foreign energy suppliers and transporters, as well as alternative forms of energy, including, but not limited to, solar power, wind power, geothermal energy and biofuels such as ethanol and biodiesel;
- the capital intensive nature of our businesses;
- the profitability of assets or businesses acquired or constructed by us;
- our ability to make cost-saving changes in operations;
- risks of marketing, trading and hedging activities, including the risks of changes in energy prices or the financial condition of our counterparties;
- the uncertainty of estimates, including accruals and costs of environmental remediation;
- the timing and extent of changes in energy commodity prices;
- the effects of changes in governmental policies and regulatory actions, including changes with respect to income and other taxes, pipeline safety, environmental compliance, climate change initiatives and authorized rates of recovery of natural gas and natural gas transportation costs;
- the impact on drilling and production by factors beyond our control, including the demand for natural gas and crude oil; producers' desire and ability to obtain necessary permits; reserve performance; and capacity constraints on the pipelines that transport crude oil, natural gas and NGLs from producing areas and our facilities;
- difficulties or delays experienced by trucks, railroads or pipelines in delivering products to or from our terminals or pipelines;
- changes in demand for the use of natural gas, NGLs and crude oil because of market conditions caused by concerns about climate change;
- the impact of unforeseen changes in interest rates, debt and equity markets, inflation rates, economic recession and other external factors over which we have no control, including the effect on pension and postretirement expense and funding resulting from changes in equity and bond market returns;
- our indebtedness and guarantee obligations could make us vulnerable to general adverse economic and industry conditions, limit our ability to borrow additional funds and/or place us at competitive disadvantages compared with our competitors that have less debt or have other adverse consequences;
- actions by rating agencies concerning our credit;
- the results of administrative proceedings and litigation, regulatory actions, rule changes and receipt of expected clearances involving any local, state or federal regulatory body, including the FERC, the National Transportation Safety Board, the PHMSA, the EPA and CFTC;
- our ability to access capital at competitive rates or on terms acceptable to us;
- risks associated with adequate supply to our gathering, processing, fractionation and pipeline facilities, including production declines that outpace new drilling or extended periods of ethane rejection;

- the risk that material weaknesses or significant deficiencies in our internal controls over financial reporting could emerge or that minor problems could become significant;
- the impact and outcome of pending and future litigation;
- the ability to market pipeline capacity on favorable terms, including the effects of:
  - future demand for and prices of natural gas, NGLs and crude oil;
  - competitive conditions in the overall energy market;
  - availability of supplies of Canadian and United States natural gas and crude oil; and
  - availability of additional storage capacity;
- performance of contractual obligations by our customers, service providers, contractors and shippers;
- the timely receipt of approval by applicable governmental entities for construction and operation of our pipeline and other projects and required regulatory clearances;
- our ability to acquire all necessary permits, consents or other approvals in a timely manner, to promptly obtain all necessary materials and supplies required for construction, and to construct gathering, processing, storage, fractionation and transportation facilities without labor or contractor problems;
- the mechanical integrity of facilities operated;
- demand for our services in the proximity of our facilities;
- our ability to control operating costs;
- acts of nature, sabotage, terrorism or other similar acts that cause damage to our facilities or our suppliers' or shippers' facilities;
- economic climate and growth in the geographic areas in which we do business;
- the risk of a prolonged slowdown in growth or decline in the United States or international economies, including liquidity risks in United States or foreign credit markets;
- the impact of recently issued and future accounting updates and other changes in accounting policies;
- the possibility of future terrorist attacks or the possibility or occurrence of an outbreak of, or changes in, hostilities or changes in the political conditions throughout the world;
- the risk of increased costs for insurance premiums, security or other items as a consequence of terrorist attacks;
- risks associated with pending or possible acquisitions and dispositions, including our ability to finance or integrate any such acquisitions and any regulatory delay or conditions imposed by regulatory bodies in connection with any such acquisitions and dispositions;
- the impact of uncontracted capacity in our assets being greater or less than expected;
- the ability to recover operating costs and amounts equivalent to income taxes, costs of property, plant and equipment and regulatory assets in our state and FERC-regulated rates;
- the composition and quality of the natural gas and NGLs we gather and process in our plants and transport on our pipelines;
- the efficiency of our plants in processing natural gas and extracting and fractionating NGLs;
- the impact of potential impairment charges;
- the risk inherent in the use of information systems in our respective businesses, implementation of new software and hardware, and the impact on the timeliness of information for financial reporting;
- our ability to control construction costs and completion schedules of our pipelines and other projects; and
- the risk factors listed in the reports we have filed and may file with the SEC, which are incorporated by reference.

These factors are not necessarily all of the important factors that could cause actual results to differ materially from those expressed in any of our forward-looking statements. Other factors could also have material adverse effects on our future results. These and other risks are described in greater detail in Part I, Item 1A, Risk Factors, in this Annual Report and in our other filings that we make with the SEC, which are available via the SEC's website at www.sec.gov and our website at www.oneok.com. All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by these factors. Any such forward-looking statement speaks only as of the date on which such statement is made, and other than as required under securities laws, we undertake no obligation to update publicly any forward-looking statement whether as a result of new information, subsequent events or change in circumstances, expectations or otherwise.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Our exposure to market risk discussed below includes forward-looking statements and represents an estimate of possible changes in future earnings that could occur assuming hypothetical future movements in interest rates or commodity prices. Our views on market risk are not necessarily indicative of actual results that may occur and do not represent the maximum possible gains and losses that may occur since actual gains and losses will differ from those estimated based on actual fluctuations in interest rates or commodity prices and the timing of transactions.

We are exposed to market risk due to commodity price and interest-rate volatility. Market risk is the risk of loss arising from adverse changes in market rates and prices. We may use financial instruments, including forward sales, swaps, options and futures, to manage the risks of certain identifiable or anticipated transactions and achieve more predictable cash flows. Our risk-management function follows established policies and procedures to monitor our natural gas, condensate and NGL marketing activities and interest rates to ensure our hedging activities mitigate market risks. We do not use financial instruments for trading purposes.

We record derivative instruments at fair value. We estimate the fair value of derivative instruments using available market information and appropriate valuation techniques. Changes in derivative instruments' fair values are recognized in earnings unless the instrument qualifies as a hedge and meets specific hedge accounting criteria. The effective portion of qualifying derivative instruments' gains and losses may offset the hedged items' related results in earnings for a fair value hedge or be deferred in accumulated other comprehensive income (loss) for a cash flow hedge.

COMMODITY PRICE RISK

As part of our hedging strategy, we use commodity derivative financial instruments and physical-forward contracts described in Note D of the Notes to Consolidated Financial Statements in this Annual Report to reduce the impact of near-term price fluctuations of natural gas, NGLs and condensate.

Although our businesses are primarily fee-based, in our Natural Gas Gathering and Processing segment, we are exposed to commodity price risk as a result of retaining a portion of the commodity sales proceeds associated with our POP with fee contracts. We have restructured a portion of our POP with fee contracts to include significantly higher fees, which reduces our equity volumes and the related commodity price exposure. However, under certain POP with fee contracts, our fees and POP percentage may increase or decrease if production volumes, delivery pressures or commodity prices change relative to specified thresholds. We are exposed to basis risk between the various production and market locations where we buy and sell commodities.

The following tables set forth hedging information for our Natural Gas Gathering and Processing segment's forecasted equity volumes for the periods indicated:

	Year Ending December 31, 2018		
	Volumes Hedged	Average Price	Percentage Hedged
NGLs - excluding ethane (*MBbl/d*) - Conway/Mont Belvieu	8.1	$ 0.66 / gallon	79%
Condensate (*MBbl/d*) - WTI-NYMEX	2.4	$ 52.65 / Bbl	77%
Natural gas (*BBtu/d*) - NYMEX and basis	67.2	$ 2.79 / MMBtu	83%

	Year Ending December 31, 2019		
	Volumes Hedged	Average Price	Percentage Hedged
NGLs - excluding ethane (*MBbl/d*) - Conway/Mont Belvieu	7.2	$ 0.71 / gallon	71%
Condensate (*MBbl/d*) - WTI-NYMEX	2.2	$ 56.90 / Bbl	65%

Our Natural Gas Gathering and Processing segment's commodity price sensitivity is estimated as a hypothetical change in the price of NGLs, crude oil and natural gas at December 31, 2017. Condensate sales are typically based on the price of crude oil. We estimate the following for our forecasted equity volumes, including the effects of hedging information set forth above, and assuming normal operating conditions:

- a $0.01 per-gallon change in the composite price of NGLs would change 12-month adjusted EBITDA for the years ending December 31, 2018 and 2019, by approximately $1.9 million and $2.9 million, respectively;
- a $1.00 per-barrel change in the price of crude oil would change 12-month adjusted EBITDA for the years ending December 31, 2018 and 2019, by approximately $0.5 million and $0.6 million, respectively; and
- a $0.10 per-MMBtu change in the price of residue natural gas would change 12-month adjusted EBITDA for the years ending December 31, 2018 and 2019, by approximately $0.5 million and $2.8 million, respectively.

These estimates do not include any effects on demand for our services or natural gas processing plant operations that might be caused by, or arise in conjunction with, commodity price fluctuations. For example, a change in the gross processing spread may cause a change in the amount of ethane extracted from the natural gas stream, impacting gathering and processing financial results for certain contracts.

See Note D for more information on our hedging activities.

INTEREST-RATE RISK

We are exposed to interest-rate risk through our $2.5 Billion Credit Agreement, commercial paper program and long-term debt issuances. Future increases in LIBOR, corporate commercial paper rates or corporate bond rates could expose us to increased interest costs on future borrowings. We manage interest-rate risk through the use of fixed-rate debt, floating-rate debt and interest-rate swaps. Interest-rate swaps are agreements to exchange interest payments at some future point based on specified notional amounts. At December 31, 2017, and December 31, 2016, we had forward-starting interest-rate swaps with notional amounts totaling $1.3 billion and $1.2 billion, respectively, to hedge the variability of interest payments on a portion of our forecasted debt issuances and interest-rate swaps with notional amounts totaling $500 million and $1.0 billion, respectively, to hedge the variability of our LIBOR-based interest payments. All of our interest-rate swaps are designated as cash flow hedges. At December 31, 2017, we had derivative assets of $50.0 million related to these interest-rate swaps. At December 31, 2016, we had derivative assets of $47.5 million and derivative liabilities of $12.8 million related to these interest-rate swaps.

In July 2017, we settled $400 million of our forward-starting interest-rate swaps upon the completion of our underwritten public offering of $1.2 billion senior unsecured notes and $500 million of our interest-rate swaps used to hedge our LIBOR-based interest payments. In January 2018, we settled the remaining $500 million of our interest-rate swaps used to hedge our LIBOR-based interest payments.

See Note D for more information on our hedging activities.

COUNTERPARTY CREDIT RISK

We assess the creditworthiness of our counterparties on an ongoing basis and require security, including prepayments and other forms of collateral, when appropriate. Certain of our counterparties may be impacted by a relatively low commodity price environment and could experience financial problems, which could result in nonpayment and/or nonperformance, which could impact adversely our results of operations.

Customer concentration - In 2017, no single customer represented more than 10 percent of our consolidated revenues and only 25 customers individually represented one percent or more of our consolidated revenues, the majority of which are investment-grade customers, as rated by S&P, Moody's or our comparable internal ratings, or secured by letters of credit or other collateral.

Natural Gas Gathering and Processing - Our Natural Gas Gathering and Processing segment derives services revenue primarily from crude oil and natural gas producers, which include both large integrated and independent exploration and production companies. In this segment, our downstream commodity sales customers are primarily utilities, large industrial companies, marketing companies and our NGL affiliate. We are not typically exposed to material credit risk with producers under POP with fee contracts as we sell the commodities and remit a portion of the sales proceeds back to the producer customer. In 2017 and 2016, approximately 95 percent and 99 percent, respectively, of the downstream commodity sales in our Natural Gas Gathering and Processing segment were made to investment-grade customers, as rated by S&P, Moody's or our comparable internal ratings, or were secured by letters of credit or other collateral.

Natural Gas Liquids - Our Natural Gas Liquids segment's customers are primarily NGL and natural gas gathering and processing companies; large integrated and independent crude oil and natural gas production companies; propane distributors; ethanol producers; and petrochemical, refining and NGL marketing companies. We earn fee-based revenue from NGL and natural gas gathering and processing customers and natural gas liquids pipeline transportation customers. We are not typically exposed to material credit risk on the majority of our exchange services fee revenues, as we purchase NGLs from our gathering and processing customers and deduct our fee from the amounts we remit. We also earn sales revenue on the downstream sales of NGL products. In 2017 and 2016, approximately 80 percent of this segment's commodity sales were made to investment-grade customers, as rated by S&P, Moody's or our comparable internal ratings, or were secured by letters of credit or other collateral. In addition, the majority of our Natural Gas Liquids segment's pipeline tariffs provide us the ability to require security from shippers.

Natural Gas Pipelines - Our Natural Gas Pipelines segment's customers are primarily local natural gas distribution companies, electric-generation facilities, large industrial companies, municipalities, producers and marketing companies. In 2017 and 2016, approximately 90 percent and 85 percent, respectively, of our revenues in this segment were from investment-grade customers, as rated by S&P, Moody's or our comparable internal ratings, or were secured by letters of credit or other collateral. In addition, the majority of our Natural Gas Pipelines segment's pipeline tariffs provide us the ability to require security from shippers.

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of ONEOK, Inc.:

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of ONEOK, Inc. and its subsidiaries (the "Company") as of December 31, 2017 and December 31, 2016, and the related consolidated statements of income, comprehensive income, changes in equity and cash flows for each of the three years in the period ended December 31, 2017, including the related notes (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and December 31, 2016, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2017 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the COSO.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, appearing in Management's Annual Report on Internal Control over Financial Reporting under Item 9A. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

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

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

/s/ PricewaterhouseCoopers LLP

Tulsa, OK
February 27, 2018

We have served as the Company's auditor since 2007.

ONEOK, Inc. and Subsidiaries
CONSOLIDATED STATEMENTS OF INCOME

	Years Ended December 31,		
	2017	**2016**	**2015**
	(Thousands of dollars, except per share amounts)		
Revenues			
Commodity sales	**$ 9,862,652**	$ 6,858,456	$ 6,098,343
Services	**2,311,255**	2,062,478	1,664,863
Total revenues	**12,173,907**	8,920,934	7,763,206
Cost of sales and fuel (exclusive of items shown separately below)	**9,538,045**	6,496,124	5,641,052
Operations and maintenance	**735,190**	668,335	605,748
Depreciation and amortization	**406,335**	391,585	354,620
Impairment of long-lived assets (Note E)	**15,970**	—	83,673
General taxes	**98,396**	88,849	87,583
Gain on sale of assets	**(924)**	(9,635)	(5,629)
Operating income	**1,380,895**	1,285,676	996,159
Equity in net earnings from investments (Note N)	**159,278**	139,690	125,300
Impairment of equity investments (Note N)	**(4,270)**	—	(180,583)
Allowance for equity funds used during construction	**107**	209	2,179
Other income	**15,385**	6,091	368
Other expense	**(24,936)**	(4,059)	(4,760)
Interest expense (net of capitalized interest of $5,510, $10,591 and $36,572, respectively)	**(485,658)**	(469,651)	(416,787)
Income before income taxes	**1,040,801**	957,956	521,876
Income taxes (Note M)	**(447,282)**	(212,406)	(136,600)
Income from continuing operations	**593,519**	745,550	385,276
Income (loss) from discontinued operations, net of tax	**—**	(2,051)	(6,081)
Net income	**593,519**	743,499	379,195
Less: Net income attributable to noncontrolling interests	**205,678**	391,460	134,218
Net income attributable to ONEOK	**387,841**	352,039	244,977
Less: Preferred stock dividends	**767**	—	—
Net income available to common shareholders	**$ 387,074**	$ 352,039	$ 244,977
Amounts available to common shareholders:			
Income from continuing operations	**$ 387,074**	$ 354,090	$ 251,058
Income (loss) from discontinued operations	**—**	(2,051)	(6,081)
Net income	**$ 387,074**	$ 352,039	$ 244,977
Basic earnings per common share:			
Income from continuing operations (Note J)	**$ 1.30**	$ 1.68	$ 1.19
Income (loss) from discontinued operations	**—**	(0.01)	(0.02)
Net income	**$ 1.30**	$ 1.67	$ 1.17
Diluted earnings per common share:			
Income from continuing operations (Note J)	**$ 1.29**	$ 1.67	$ 1.19
Income (loss) from discontinued operations	**—**	(0.01)	(0.03)
Net income	**$ 1.29**	$ 1.66	$ 1.16
Average shares (*thousands*)			
Basic	**297,477**	211,128	210,208
Diluted	**299,780**	212,383	210,541
Dividends declared per share of common stock	**$ 2.72**	$ 2.46	$ 2.43

See accompanying Notes to Consolidated Financial Statements.

ONEOK, Inc. and Subsidiaries
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Years Ended December 31,		
	2017	**2016**	**2015**
	(*Thousands of dollars*)		
Net income	**$ 593,519**	$ 743,499	$ 379,195
Other comprehensive income (loss), net of tax			
Unrealized gains (losses) on derivatives, net of tax of $19,006, $5,452 and $(6,138), respectively	**(21,408)**	(30,300)	41,362
Realized (gains) losses on derivatives recognized in net income, net of tax of $(26,899), $230 and $8,815, respectively	**63,687**	(6,977)	(54,709)
Unrealized holding gains (losses) on available-for-sale securities, net of tax of $0, $0 and $648, respectively	**—**	—	(955)
Change in pension and postretirement benefit plan liability, net of tax of $(878), $11,128 and $(10,278), respectively	**(4,175)**	(16,693)	15,416
Other comprehensive income (loss) on investments in unconsolidated affiliates, net of tax of $145, $270 and $293, respectively	**(970)**	(1,505)	(1,632)
Total other comprehensive income (loss), net of tax	**37,134**	(55,475)	(518)
Comprehensive income	**630,653**	688,024	378,677
Less: Comprehensive income attributable to noncontrolling interests	**236,704**	363,093	124,589
Comprehensive income attributable to ONEOK	**$ 393,949**	$ 324,931	$ 254,088

See accompanying Notes to Consolidated Financial Statements.

ONEOK, Inc. and Subsidiaries
CONSOLIDATED BALANCE SHEETS

	December 31, 2017	December 31, 2016
Assets	(*Thousands of dollars*)	
Current assets		
Cash and cash equivalents	**$ 37,193**	$ 248,875
Accounts receivable, net	**1,202,951**	872,430
Materials and supplies	**90,301**	60,912
Natural gas and natural gas liquids in storage	**342,293**	140,034
Commodity imbalances	**38,712**	60,896
Other current assets	**53,008**	45,986
Assets of discontinued operations	**—**	551
Total current assets	**1,764,458**	1,429,684
Property, plant and equipment		
Property, plant and equipment	**15,559,667**	15,078,497
Accumulated depreciation and amortization	**2,861,541**	2,507,094
Net property, plant and equipment (Note E)	**12,698,126**	12,571,403
Investments and other assets		
Investments in unconsolidated affiliates (Note N)	**1,003,156**	958,807
Goodwill and intangible assets (Note F)	**993,460**	1,005,359
Deferred income taxes (Note M)	**205,907**	—
Other assets	**180,830**	162,998
Assets of discontinued operations	**—**	10,500
Total investments and other assets	**2,383,353**	2,137,664
Total assets	**$ 16,845,937**	$ 16,138,751

ONEOK, Inc. and Subsidiaries

CONSOLIDATED BALANCE SHEETS

(Continued)

	December 31, 2017	**December 31, 2016**
Liabilities and equity	*(Thousands of dollars)*	
Current liabilities		
Current maturities of long-term debt (Note G)	**$ 432,650**	$ 410,650
Short-term borrowings (Note G)	**614,673**	1,110,277
Accounts payable	**1,140,571**	874,731
Commodity imbalances	**164,161**	142,646
Accrued interest	**135,309**	112,514
Other current liabilities	**179,971**	166,042
Liabilities of discontinued operations	**—**	19,841
Total current liabilities	**2,667,335**	2,836,701
Long-term debt, excluding current maturities (Note G)	**8,091,629**	7,919,996
Deferred credits and other liabilities		
Deferred income taxes (Note M)	**52,697**	1,623,822
Other deferred credits	**348,924**	321,846
Liabilities of discontinued operations	**—**	7,471
Total deferred credits and other liabilities	**401,621**	1,953,139
Commitments and contingencies (Note O)		
Equity (Note H)		
ONEOK shareholders' equity:		
Preferred stock, $0.01 par value: issued 20,000 shares at December 31, 2017, and no shares at December 31, 2016	**—**	—
Common stock, $0.01 par value: authorized 1,200,000,000 shares; issued 423,166,234 shares and outstanding 388,703,543 shares at December 31, 2017; authorized 600,000,000 shares; issued 245,811,180 shares and outstanding 210,681,661 shares at December 31, 2016	**4,232**	2,458
Paid-in capital	**6,588,878**	1,234,314
Accumulated other comprehensive loss (Note I)	**(188,530)**	(154,350)
Retained earnings	**—**	—
Treasury stock, at cost: 34,462,691 shares at December 31, 2017, and 35,129,519 shares at December 31, 2016	**(876,713)**	(893,677)
Total ONEOK shareholders' equity	**5,527,867**	188,745
Noncontrolling interests in consolidated subsidiaries	**157,485**	3,240,170
Total equity	**5,685,352**	3,428,915
Total liabilities and equity	**$ 16,845,937**	$ 16,138,751

See accompanying Notes to Consolidated Financial Statements.

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ONEOK, Inc. and Subsidiaries
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2017	2016	2015
	(*Thousands of dollars*)		
Operating activities			
Net income	**$ 593,519**	$ 743,499	$ 379,195
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	**406,335**	391,585	354,620
Impairment charges	**20,240**	—	264,256
Noncash contribution of preferred stock, net of tax	**12,600**	—	—
Equity in net earnings from investments	**(159,278)**	(139,690)	(125,300)
Distributions received from unconsolidated affiliates	**167,372**	144,673	122,003
Deferred income taxes	**437,917**	211,638	137,737
Share-based compensation expense	**26,262**	40,563	16,435
Pension and postretirement benefit expense, net of contributions	**4,079**	11,643	14,814
Allowance for equity funds used during construction	**(107)**	(209)	(2,179)
Gain on sale of assets	**(924)**	(9,635)	(5,629)
Changes in assets and liabilities:			
Accounts receivable	**(330,521)**	(285,806)	157,051
Natural gas and natural gas liquids in storage	**(202,259)**	(11,950)	6,050
Accounts payable	**261,305**	287,632	(205,143)
Commodity imbalances, net	**43,699**	45,971	(4,083)
Settlement of exit activities liabilities	**(9,707)**	(19,906)	(38,536)
Accrued interest	**22,795**	(16,529)	24,166
Risk-management assets and liabilities	**37,617**	(78,136)	(32,370)
Other assets and liabilities, net	**(15,532)**	37,998	(40,259)
Cash provided by operating activities	**1,315,412**	1,353,341	1,022,828
Investing activities			
Capital expenditures (less allowance for equity funds used during construction)	**(512,393)**	(624,634)	(1,188,312)
Contributions to unconsolidated affiliates	**(87,861)**	(68,275)	(27,540)
Distributions received from unconsolidated affiliates in excess of cumulative earnings	**28,742**	52,044	33,915
Proceeds from sale of assets	**3,879**	25,420	3,825
Other	**—**	—	(12,607)
Cash used in investing activities	**(567,633)**	(615,445)	(1,190,719)
Financing activities			
Dividends paid	**(829,414)**	(517,601)	(509,197)
Distributions to noncontrolling interests	**(276,260)**	(549,419)	(535,825)
Borrowing (repayment) of short-term borrowings, net	**(495,604)**	563,937	(508,956)
Issuance of long-term debt, net of discounts	**1,190,496**	1,000,000	1,291,506
Debt financing costs	**(11,425)**	(2,770)	(17,515)
Repayment of long-term debt	**(994,776)**	(1,108,040)	(7,753)
Issuance of common stock	**471,358**	21,971	20,669
Issuance of common units, net of issuance costs	**—**	—	375,660
Other	**(13,836)**	5,403	(15,848)
Cash provided by (used in) financing activities	**(959,461)**	(586,519)	92,741
Change in cash and cash equivalents	**(211,682)**	151,377	(75,150)
Change in cash and cash equivalents included in discontinued operations	**—**	(121)	(43)
Change in cash and cash equivalents from continuing operations	**(211,682)**	151,256	(75,193)
Cash and cash equivalents at beginning of period	**248,875**	97,619	172,812
Cash and cash equivalents at end of period	**$ 37,193**	$ 248,875	$ 97,619
Supplemental cash flow information:			
Cash paid for interest, net of amounts capitalized	**$ 432,210**	$ 461,208	$ 367,835
Cash paid for income taxes	**$ 6,633**	$ 361	$ 3,324

See accompanying Notes to Consolidated Financial Statements.

ONEOK, Inc. and Subsidiaries
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

	ONEOK Shareholders' Equity				
	Common Stock Issued	**Preferred Stock Issued**	**Common Stock**	**Preferred Stock**	**Paid-in Capital**
	(*Shares*)		(*Thousands of dollars*)		
January 1, 2015	245,811,180	—	$ 2,458	$ —	$ 1,541,583
Net income	—	—	—	—	—
Other comprehensive income (loss)	—	—	—	—	—
Common stock issued	—	—	—	—	(7,550)
Common stock dividends - $2.43 per share (Note H)	—	—	—	—	(126,090)
Issuance of common units of ONEOK Partners	—	—	—	—	(34,446)
Distributions to noncontrolling interests	—	—	—	—	—
Other	—	—	—	—	4,947
December 31, 2015	245,811,180	—	2,458	—	1,378,444
Net income	—	—	—	—	—
Other comprehensive income (loss) (Note I)	—	—	—	—	—
Common stock issued	—	—	—	—	2,331
Common stock dividends - $2.46 per share (Note H)	—	—	—	—	(165,562)
Distributions to noncontrolling interests	—	—	—	—	—
Other	—	—	—	—	19,101
December 31, 2016	245,811,180	—	2,458	—	1,234,314
Cumulative effect adjustment for adoption of ASU 2016-09	—	—	—	—	—
Net income	—	—	—	—	—
Other comprehensive income (loss) (Note I)	—	—	—	—	—
Common stock issued	**8,434,223**	—	**85**	—	**456,537**
Preferred stock issued	—	**20,000**	—	—	**20,000**
Common stock dividends - $2.72 per share (Note H)	—	—	—	—	**(367,578)**
Preferred stock dividends (Note H)	—	—	—	—	**(767)**
Distributions to noncontrolling interests	—	—	—	—	—
Acquisition of ONEOK Partners' noncontrolling interests (Note B)	**168,920,831**	—	**1,689**	—	**5,228,580**
Other	—	—	—	—	**17,792**
December 31, 2017	**423,166,234**	**20,000**	**$ 4,232**	**$ —**	**$ 6,588,878**

ONEOK, Inc. and Subsidiaries

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(Continued)

	ONEOK Shareholders' Equity				
	Accumulated Other Comprehensive Loss	**Retained Earnings**	**Treasury Stock**	**Noncontrolling Interests in Consolidated Subsidiaries**	**Total Equity**
			(*Thousands of dollars*)		
January 1, 2015	$ (136,353)	$ 138,128	$ (953,701)	$ 3,413,768	$ 4,005,883
Net income	—	244,977	—	134,218	379,195
Other comprehensive income (loss)	9,111	—	—	(9,629)	(518)
Common stock issued	—	—	35,839	—	28,289
Common stock dividends - $2.43 per share (Note H)	—	(383,107)	—	—	(509,197)
Issuance of common units of ONEOK Partners	—	—	—	428,443	393,997
Distributions to noncontrolling interests	—	—	—	(535,825)	(535,825)
Other	—	2	—	(437)	4,512
December 31, 2015	(127,242)	—	(917,862)	3,430,538	3,766,336
Net income	—	352,039	—	391,460	743,499
Other comprehensive income (loss) (Note I)	(27,108)	—	—	(28,367)	(55,475)
Common stock issued	—	—	24,185	—	26,516
Common stock dividends - $2.46 per share (Note H)	—	(352,039)	—	—	(517,601)
Distributions to noncontrolling interests	—	—	—	(549,419)	(549,419)
Other	—	—	—	(4,042)	15,059
December 31, 2016	(154,350)	—	(893,677)	3,240,170	3,428,915
Cumulative effect adjustment for adoption of ASU 2016-09	**—**	**73,368**	**—**	**—**	**73,368**
Net income	**—**	**387,841**	**—**	**205,678**	**593,519**
Other comprehensive income (loss) (Note I)	**6,108**	**—**	**—**	**31,026**	**37,134**
Common stock issued	**—**	**—**	**16,964**	**—**	**473,586**
Preferred stock issued	**—**	**—**	**—**	**—**	**20,000**
Common stock dividends - $2.72 per share (Note H)	**—**	**(461,209)**	**—**	**—**	**(828,787)**
Preferred stock dividends (Note H)	**—**	**—**	**—**	**—**	**(767)**
Distributions to noncontrolling interests	**—**	**—**	**—**	**(276,260)**	**(276,260)**
Acquisition of ONEOK Partners' noncontrolling interests (Note B)	**(40,288)**	**—**	**—**	**(3,043,519)**	**2,146,462**
Other	**—**	**—**	**—**	**390**	**18,182**
December 31, 2017	**$ (188,530)**	**$ —**	**$ (876,713)**	**$ 157,485**	**$ 5,685,352**

See accompanying Notes to Consolidated Financial Statements.

A. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization and Nature of Operations - We are a corporation incorporated under the laws of the state of Oklahoma, and our common stock is listed on the NYSE under the trading symbol "OKE." On June 30, 2017, we completed the Merger Transaction at a fixed exchange ratio of 0.985 of a share of our common stock for each ONEOK Partners common unit that we did not already own. We issued 168.9 million shares of our common stock to third-party common unitholders of ONEOK Partners in exchange for all of the 171.5 million outstanding common units of ONEOK Partners that we previously did not own. No fractional shares were issued in the Merger Transaction, and ONEOK Partners common unitholders instead received cash in lieu of fractional shares. As a result of the completion of the Merger Transaction, common units of ONEOK Partners are no longer publicly traded. For additional information on this transaction, see Note B.

Our operations include gathering and processing of natural gas produced from crude oil and natural gas wells. We gather and process natural gas in the Mid-Continent region, which includes the NGL-rich STACK and SCOOP areas and the Cana-Woodford Shale, Woodford Shale, Springer Shale, Meramec, Granite Wash and Mississippian Lime formations of Oklahoma and Kansas, and the Hugoton and Central Kansas Uplift Basins in Kansas. We also gather and/or process natural gas in two producing basins in the Rocky Mountain region: the Williston Basin, which spans portions of North Dakota and Montana and includes the oil-producing, NGL-rich Bakken Shale and Three Forks formations; and the Powder River Basin located in Wyoming, which includes the NGL-rich Niobrara Shale and Frontier, Turner and Sussex formations in Wyoming.

Our natural gas liquids assets consist of facilities that gather, fractionate and treat NGLs and store NGL products primarily in Oklahoma, Kansas, Texas, New Mexico and the Rocky Mountain region where we provide midstream services to producers of NGLs. We own or have an ownership interest in FERC-regulated natural gas liquids gathering and distribution pipelines in Oklahoma, Kansas, Texas, New Mexico, Montana, North Dakota, Wyoming and Colorado, and terminal and storage facilities in Missouri, Nebraska, Iowa and Illinois. We also own FERC-regulated natural gas liquids distribution and refined petroleum products pipelines in Kansas, Missouri, Nebraska, Iowa, Illinois and Indiana that connect our Mid-Continent assets with Midwest markets, including Chicago, Illinois. We own and operate truck- and rail-loading and -unloading facilities that interconnect with our NGL fractionation and pipeline assets.

We operate interstate and intrastate natural gas transmission pipelines and natural gas storage facilities. Our FERC-regulated interstate natural gas pipeline assets transport natural gas through pipelines in North Dakota, Minnesota, Wisconsin, Illinois, Indiana, Kentucky, Tennessee, Oklahoma, Texas and New Mexico. Our intrastate natural gas pipeline assets in Oklahoma transport natural gas throughout the state and have access to the major natural gas producing areas in the Mid-Continent region, which include the STACK and SCOOP areas and the Cana-Woodford Shale, Woodford Shale, Springer Shale, Meramec, Granite Wash and Mississippian Lime formations. The Roadrunner pipeline transports natural gas from the Permian Basin in West Texas to the Mexican border near El Paso, Texas, and is fully subscribed with 25-year firm demand charge, fee-based agreements. We own underground natural gas storage facilities in Oklahoma and Texas that are connected to our intrastate natural gas pipeline assets. We also have underground natural gas storage facilities in Kansas.

Consolidation - Our Consolidated Financial Statements include our accounts and the accounts of our subsidiaries over which we have control or are the primary beneficiary. All intercompany balances and transactions have been eliminated in consolidation.

Investments in unconsolidated affiliates are accounted for using the equity method if we have the ability to exercise significant influence over operating and financial policies of our investee. Under this method, an investment is carried at its acquisition cost and adjusted each period for contributions made, distributions received and our share of the investee's comprehensive income. For the investments we account for under the equity method, the premium or excess cost over underlying fair value of net assets is referred to as equity-method goodwill. Impairment of equity investments is recorded when the impairments are other than temporary. These amounts are recorded as investments in unconsolidated affiliates on our accompanying Consolidated Balance Sheets. See Note N for disclosures of our unconsolidated affiliates.

Distributions paid to us from our unconsolidated affiliates are classified as operating activities on our Consolidated Statements of Cash Flows until the cumulative distributions exceed our proportionate share of income from the unconsolidated affiliate since the date of our initial investment. The amount of cumulative distributions paid to us that exceeds our cumulative proportionate share of income in each period represents a return of investment and is classified as an investing activity on our Consolidated Statements of Cash Flows.

Use of Estimates - The preparation of our Consolidated Financial Statements and related disclosures in accordance with GAAP requires us to make estimates and assumptions with respect to values or conditions that cannot be known with certainty that affect the reported amounts on our Consolidated Financial Statements. Items that may be estimated include, but are not limited to, the economic useful life of assets, fair value of assets, liabilities and equity-method investments, obligations under employee benefit plans, provisions for uncollectible accounts receivable, expenses for services received but for which no invoice has been received, provision for income taxes, including any deferred tax valuation allowances, the results of litigation and various other recorded or disclosed amounts. In addition, a portion of our revenues and cost of sales and fuel are recorded based on current month estimated volumes and prices. The estimates are reversed in the following month and recorded with actual volumes and prices.

We evaluate these estimates on an ongoing basis using historical experience, consultation with experts and other methods we consider reasonable based on the particular circumstances. Nevertheless, actual results may differ significantly from the estimates. Any effects on our financial position or results of operations from revisions to these estimates are recorded in the period when the facts that give rise to the revision become known.

Fair Value Measurements - We define fair value as the price that would be received from the sale of an asset or the transfer of a liability in an orderly transaction between market participants at the measurement date. We use market and income approaches to determine the fair value of our assets and liabilities and consider the markets in which the transactions are executed. We measure the fair value of a group of financial assets and liabilities consistent with how a market participant would price the net risk exposure at the measurement date.

While many of the contracts in our derivative portfolio are executed in liquid markets where price transparency exists, some contracts are executed in markets for which market prices may exist, but the market may be relatively inactive. This results in limited price transparency that requires management's judgment and assumptions to estimate fair values. For certain transactions, we utilize modeling techniques using NYMEX-settled pricing data and implied forward LIBOR curves. Inputs into our fair value estimates include commodity-exchange prices, over-the-counter quotes, historical correlations of pricing data, data obtained from third-party pricing services and LIBOR and other liquid money-market instrument rates. We validate our valuation inputs with third-party information and settlement prices from other sources, where available.

In addition, as prescribed by the income approach, we compute the fair value of our derivative portfolio by discounting the projected future cash flows from our derivative assets and liabilities to present value using interest-rate yields to calculate present-value discount factors derived from LIBOR, Eurodollar futures and the LIBOR interest-rate swaps market. We also take into consideration the potential impact on market prices of liquidating positions in an orderly manner over a reasonable period of time under current market conditions. We consider current market data in evaluating counterparties', as well as our own, nonperformance risk, net of collateral, by using specific and sector bond yields and monitoring the credit default swap markets. Although we use our best estimates to determine the fair value of the derivative contracts we have executed, the ultimate market prices realized could differ from our estimates, and the differences could be material.

The fair value of our forward-starting interest-rate swaps are determined using financial models that incorporate the implied forward LIBOR yield curve for the same period as the future interest-rate swap settlements.

Fair Value Hierarchy - At each balance sheet date, we utilize a fair value hierarchy to classify fair value amounts recognized or disclosed in our financial statements based on the observability of inputs used to estimate such fair value. The levels of the hierarchy are described below:

- Level 1 - fair value measurements are based on unadjusted quoted prices for identical securities in active markets, including NYMEX-settled prices. These balances are comprised primarily of exchange-traded derivative contracts for natural gas and crude oil.
- Level 2 - fair value measurements are based on significant observable pricing inputs, such as NYMEX-settled prices for natural gas and crude oil, and financial models that utilize implied forward LIBOR yield curves for interest-rate swaps.
- Level 3 - fair value measurements are based on inputs that may include one or more unobservable inputs, including internally developed natural gas basis and NGL price curves that incorporate observable and unobservable market data from broker quotes, third-party pricing services, market volatilities derived from the most recent NYMEX close spot prices and forward LIBOR curves, and adjustments for the credit risk of our counterparties. We corroborate the data on which our fair value estimates are based using our market knowledge of recent transactions, analysis of historical correlations and validation with independent broker quotes. These balances categorized as Level 3 are comprised of derivatives for natural gas and NGLs. We do not believe that our Level 3 fair value estimates have a material impact

on our results of operations, as the majority of our derivatives are accounted for as hedges for which ineffectiveness has not been material.

Determining the appropriate classification of our fair value measurements within the fair value hierarchy requires management's judgment regarding the degree to which market data is observable or corroborated by observable market data. We categorize derivatives for which fair value is determined using multiple inputs within a single level, based on the lowest level input that is significant to the fair value measurement in its entirety.

See Note C for discussion of our fair value measurements.

Cash and Cash Equivalents - Cash equivalents consist of highly liquid investments, which are readily convertible into cash and have original maturities of three months or less.

Revenue Recognition - Our reportable segments recognize revenue when services are rendered or product is delivered. Our Natural Gas Gathering and Processing segment records revenues when natural gas is gathered or processed through our facilities. Our Natural Gas Liquids segment records revenues based upon contracted services and volumes exchanged or stored under service agreements in the period services are provided. A portion of our revenues for our Natural Gas Pipelines segment and our Natural Gas Liquids segment are recognized based upon contracted capacity and contracted volumes transported and stored under service agreements in the period services are provided. We disaggregate revenue on the Consolidated Statements of Income as follows:

- *Commodity sales* - Commodity sales represent the sale of NGLs, condensate and residue natural gas. We generally purchase a supplier's raw natural gas or unfractionated NGLs, which we process into marketable commodities and condensate, then we sell these commodities and condensate to downstream customers at a specified delivery point. Commodity sales are recognized upon delivery or title transfer to the customer, when revenue recognition criteria are met.
- *Service revenue* - Service revenue represents the fees generated from the performance of our services.

We enter into a variety of contract types that provide commodity sales and service revenue. We provide services primarily under the following types of contracts:

- *Fee-based* - Under fee-based arrangements, we receive a fee or fees for one or more of the following services: gathering, compression, processing, transmission and storage of natural gas; and gathering, transportation, fractionation and storage of NGLs. The revenue we earn from these arrangements generally is directly related to the volume of natural gas and NGLs that flow through our systems and facilities, and is not normally directly dependent on commodity prices. However, to the extent a sustained decline in commodity prices results in a decline in volumes, our revenues from these arrangements would be reduced. In addition, many of our arrangements provide for fixed fee, minimum volume or firm demand charges. Fee-based arrangements are reported as service revenue on the Consolidated Statements of Income.
- *Percent-of-proceeds* - Under POP arrangements in our Natural Gas Gathering and Processing segment, we generally purchase the producer's raw natural gas which we process into natural gas and natural gas liquids, then we sell these commodities and condensate to downstream customers. We remit sales proceeds to the producer according to the contractual terms and retain our portion. Typically, our POP arrangements also include a fee-based component.

In many cases, our Natural Gas Gathering and Processing segment provides services under contracts that contain a combination of the arrangements described above. When services are provided (in addition to raw natural gas purchased) under POP with fee contracts, we record such fees as service revenue on the Consolidated Statements of Income. The terms of our contracts vary based on natural gas quality conditions, the competitive environment when the contracts are signed and customer requirements.

Update - Upon adoption of Topic 606 in January 2018, certain of our revenue recognition policies changed. Based on the new guidance, certain Natural Gas Gathering and Processing segment POP with fee contracts and Natural Gas Liquids segment exchange services contracts that include the purchase of commodities are considered commodity supply contracts, as we control the commodities prior to performing services. Therefore, contractual fees in these identified contracts will be recorded as a reduction of the commodity purchase price in cost of sales and fuel, rather than as services revenue. To the extent we hold inventory related to these purchases, typically only in our Natural Gas Liquids segment, the related fees previously recorded in services revenue will not be recognized until the inventory is sold. We continue to be principal on the downstream sales of commodities purchased under our Natural Gas Gathering and Processing segment's POP with fee contracts and our Natural Gas Liquids segment's exchange services contracts that include the purchase of commodities, which is unchanged from our assessment under current guidance and will not result in any changes in the nature or timing of commodity sales revenue. The contractual fees on POP with fee contracts that include producer take-in-kind rights will continue to be recorded as services revenue, as we do not control the raw natural gas stream while we are providing midstream services.

From time to time, differences in the timing of revenues earned and our right to invoice customers may create contract assets or liabilities. At adoption, the timing of revenue on transportation contracts with tiered rates will be presented as contract assets for our Natural Gas Pipelines segment. In addition, certain contributions in aid of construction from customers will be reflected as contract liabilities that will be recognized into revenue over the contract term. In 2017 and prior periods, we recorded these reimbursements as reductions to property, plant and equipment.

Cost of Sales and Fuel - Cost of sales and fuel primarily includes (i) the cost of purchased commodities, including NGLs, natural gas and condensate, (ii) fees incurred for third-party transportation, fractionation and storage of commodities, and (iii) fuel and power costs incurred to operate our own facilities that gather, process, transport and store commodities.

Update - As described above, upon adoption of Topic 606 in January 2018, cost of sales and fuel will be reduced by the fees we charge producers under our Natural Gas Gathering and Processing segment's POP contracts and processors under our Natural Gas Liquids segment's exchange services contracts that include the purchase of commodities.

Operations and Maintenance - Operations and maintenance primarily includes (i) payroll and benefit costs, (ii) third-party costs for operations, maintenance and integrity management, regulatory compliance and environmental and safety, and (iii) other business related service costs.

Accounts Receivable - Accounts receivable represent valid claims against nonaffiliated customers for products sold or services rendered, net of allowances for doubtful accounts. We assess the creditworthiness of our counterparties on an ongoing basis and require security, including prepayments and other forms of collateral, when appropriate. Outstanding customer receivables are reviewed regularly for possible nonpayment indicators, and allowances for doubtful accounts are recorded based upon management's estimate of collectability at each balance sheet date. At December 31, 2017 and 2016, our allowance for doubtful accounts was not material.

Inventory - The values of current natural gas and NGLs in storage are determined using the lower of weighted-average cost or net realizable value. Noncurrent natural gas and NGLs are classified as property and valued at cost. Materials and supplies are valued at average cost.

Commodity Imbalances - Commodity imbalances represent amounts payable or receivable for NGL exchange contracts and natural gas pipeline imbalances and are valued at market prices. Under the majority of our NGL exchange agreements, we physically receive volumes of unfractionated NGLs, including the risk of loss and legal title to such volumes, from the exchange counterparty. In turn, we deliver NGL products back to the customer and charge them gathering, fractionation and transportation fees. To the extent that the volumes we receive under such agreements differ from those we deliver, we record a net exchange receivable or payable position with the counterparties. These net exchange receivables and payables are settled with movements of NGL products rather than with cash. Natural gas pipeline imbalances are settled in cash or in-kind, subject to the terms of the pipelines' tariffs or by agreement.

Derivatives and Risk Management - We utilize derivatives to reduce our market-risk exposure to commodity price and interest-rate fluctuations and to achieve more predictable cash flows. We record all derivative instruments at fair value, with the exception of normal purchases and normal sales transactions that are expected to result in physical delivery. Commodity price and interest-rate volatility may have a significant impact on the fair value of derivative instruments as of a given date. The accounting for changes in the fair value of a derivative instrument depends on whether it has been designated and qualifies as part of a hedging relationship and, if so, the reason for holding it. The table below summarizes the various ways in which we account for our derivative instruments and the impact on our Consolidated Financial Statements:

	Recognition and Measurement	
Accounting Treatment	**Balance Sheet**	**Income Statement**
Normal purchases and normal sales	- Fair value not recorded	- Change in fair value not recognized in earnings
Mark-to-market	- Recorded at fair value	- Change in fair value recognized in earnings
Cash flow hedge	- Recorded at fair value	- Ineffective portion of the gain or loss on the derivative instrument is recognized in earnings
	- Effective portion of the gain or loss on the derivative instrument is reported initially as a component of accumulated other comprehensive income (loss)	- Effective portion of the gain or loss on the derivative instrument is reclassified out of accumulated other comprehensive income (loss) into earnings when the forecasted transaction affects earnings
Fair value hedge	- Recorded at fair value	- The gain or loss on the derivative instrument is recognized in earnings
	- Change in fair value of the hedged item is recorded as an adjustment to book value	- Change in fair value of the hedged item is recognized in earnings

To reduce our exposure to fluctuations in natural gas, NGLs and condensate prices, we periodically enter into futures, forward purchases and sales, options or swap transactions in order to hedge anticipated purchases and sales of natural gas, NGLs and condensate. Interest-rate swaps are used from time to time to manage interest-rate risk. Under certain conditions, we designate our derivative instruments as a hedge of exposure to changes in fair values or cash flows. We formally document all relationships between hedging instruments and hedged items, as well as risk-management objectives and strategies for undertaking various hedge transactions, and methods for assessing and testing correlation and hedge ineffectiveness. We specifically identify the forecasted transaction that has been designated as the hedged item in a cash flow hedge relationship. We assess the effectiveness of hedging relationships quarterly by performing an effectiveness analysis on our fair value and cash flow hedging relationships to determine whether the hedge relationships are highly effective on a retrospective and prospective basis. We also document our normal purchases and normal sales transactions that we expect to result in physical delivery and that we elect to exempt from derivative accounting treatment.

The realized revenues and purchase costs of our derivative instruments not considered held for trading purposes and derivatives that qualify as normal purchases or normal sales that are expected to result in physical delivery are reported on a gross basis.

Cash flows from futures, forwards and swaps that are accounted for as hedges are included in the same category as the cash flows from the related hedged items in our Consolidated Statements of Cash Flows.

See Notes C and D for more discussion of our fair value measurements and risk-management and hedging activities using derivatives.

Property, Plant and Equipment - Our properties are stated at cost, including AFUDC and capitalized interest. In some cases, the cost of regulated property retired or sold, plus removal costs, less salvage, is charged to accumulated depreciation. Gains and losses from sales or transfers of nonregulated properties or an entire operating unit or system of our regulated properties are recognized in income. Maintenance and repairs are charged directly to expense.

The interest portion of AFUDC and capitalized interest represent the cost of borrowed funds used to finance construction activities for regulated and nonregulated projects, respectively. We capitalize interest costs during the construction or upgrade of qualifying assets. These costs are recorded as a reduction to interest expense. The equity portion of AFUDC represents the capitalization of the estimated average cost of equity used during the construction of major projects and is recorded in the cost of our regulated properties and as a credit to the allowance for equity funds used during construction.

Our properties are depreciated using the straight-line method over their estimated useful lives. Generally, we apply composite depreciation rates to functional groups of property having similar economic circumstances. We periodically conduct depreciation studies to assess the economic lives of our assets. For our regulated assets, these depreciation studies are completed as a part of our rate proceedings or tariff filings, and the changes in economic lives, if applicable, are implemented prospectively when the new rates are billed. For our nonregulated assets, if it is determined that the estimated economic life changes, the changes are made prospectively. Changes in the estimated economic lives of our property, plant and equipment could have a material effect on our financial position or results of operations.

Property, plant and equipment on our Consolidated Balance Sheets includes construction work in process for capital projects that have not yet been placed in service and therefore are not being depreciated. Assets are transferred out of construction work in process when they are substantially complete and ready for their intended use.

See Note E for disclosures of our property, plant and equipment.

Impairment of Goodwill and Long-Lived Assets, Including Intangible Assets - We assess our goodwill for impairment at least annually on July 1, unless events or changes in circumstances indicate an impairment may have occurred before that time. Our qualitative goodwill impairment analysis performed as of July 1, 2017, did not result in an impairment charge nor did our analysis reflect any reporting units at risk, and subsequent to that date, no event has occurred indicating that the implied fair value of each of our reporting units is less than the carrying value of its net assets.

As part of our goodwill impairment test, we may first assess qualitative factors (including macroeconomic conditions, industry and market considerations, cost factors and overall financial performance) to determine whether it is more likely than not that the fair value of each of our reporting units is less than its carrying amount. If further testing is necessary or a quantitative test is elected, we perform a two-step impairment test for goodwill. In the first step, an initial assessment is made by comparing the fair value of a reporting unit with its book value, including goodwill. If the fair value is less than the book value, an impairment is indicated, and we must perform a second test to measure the amount of the impairment. In the second test, we calculate the implied fair value of the goodwill by deducting the fair value of all tangible and intangible net assets of the reporting unit from the fair value determined in step one of the assessment. If the carrying value of the goodwill exceeds the implied fair value of the goodwill, we will record an impairment charge.

To estimate the fair value of our reporting units, we use two generally accepted valuation approaches, an income approach and a market approach, using assumptions consistent with a market participant's perspective. Under the income approach, we use anticipated cash flows over a period of years plus a terminal value and discount these amounts to their present value using appropriate discount rates. Under the market approach, we apply EBITDA multiples to forecasted EBITDA. The multiples used are consistent with historical asset transactions. The forecasted cash flows are based on average forecasted cash flows for a reporting unit over a period of years.

We assess our long-lived assets for impairment whenever events or changes in circumstances indicate that an asset's carrying amount may not be recoverable. An impairment is indicated if the carrying amount of a long-lived asset exceeds the sum of the undiscounted future cash flows expected to result from the use and eventual disposition of the asset. If an impairment is indicated, we record an impairment loss equal to the difference between the carrying value and the fair value of the long-lived asset.

For the investments we account for under the equity method, the impairment test considers whether the fair value of the equity investment as a whole, not the underlying net assets, has declined and whether that decline is other than temporary. Therefore, we periodically evaluate the amount at which we carry our equity-method investments to determine whether current events or circumstances warrant adjustments to our carrying values.

See Notes E, F and N for our long-lived assets, goodwill and intangible assets and investments in unconsolidated affiliates disclosures.

Regulation - Our intrastate natural gas transmission and natural gas liquids pipelines are subject to the rate regulation and accounting requirements of the OCC, KCC and RRC, and our natural gas transmission pipelines are regulated by the FERC under the Natural Gas Policy Act for certain services where we deliver natural gas into FERC regulated natural gas pipelines. Our interstate natural gas and natural gas liquids pipelines are subject to regulation by the FERC. In Kansas and Texas, natural gas storage may be regulated by the state and the FERC for certain types of services. Accordingly, portions of our Natural Gas Liquids and Natural Gas Pipelines segments follow the accounting and reporting guidance for regulated operations. In our Consolidated Financial Statements and our Notes to Consolidated Financial Statements, regulated operations are defined pursuant to Financial Accounting Standards Board's (FASB) ASC 980, Regulated Operations. During the rate-making process for certain of our assets, regulatory authorities set the framework for what we can charge customers for our services and establish the manner that our costs are accounted for, including allowing us to defer recognition of certain costs and permitting recovery of the amounts through rates over time as opposed to expensing such costs as incurred. Certain examples of types of regulatory guidance include costs for fuel and losses, acquisition costs, contributions in aid of construction, charges for depreciation, and gains or losses on disposition of assets. This allows us to stabilize rates over time rather than passing such costs on to the customer for immediate recovery. Actions by regulatory authorities could have an effect on the amount recovered from rate payers. Any difference in the amount recoverable and the amount deferred is recorded as income or expense at the time of the regulatory action. A write-off of regulatory assets and costs not recovered may be required if all or a portion of the regulated operations have rates that are no longer:

- established by independent, third-party regulators;
- designed to recover the specific entity's costs of providing regulated services; and
- set at levels that will recover our costs when considering the demand and competition for our services.

At December 31, 2017 and 2016, we recorded regulatory assets of $5.0 million and $5.5 million, respectively, which are currently being recovered and are expected to be recovered from our customers. Regulatory assets are being recovered as a result of approved rate proceedings over varying time periods up to 50 years. These assets are reflected in other assets on our Consolidated Balance Sheets.

Retirement and Postretirement Employee Benefits - We have defined benefit retirement plans covering certain employees and former employees. We sponsor welfare plans that provide postretirement medical and life insurance benefits to certain employees hired prior to 2017 who retire with at least five years of service. The expense and liability related to these plans is calculated using statistical and other factors that attempt to anticipate future events. These factors include assumptions about the discount rate, expected return on plan assets, rate of future compensation increases, mortality and employment length. In determining the projected benefit obligations and costs, assumptions can change from period to period and may result in material changes in the costs and liabilities we recognize. See Note L for more discussion of pension and postretirement employee benefits.

Income Taxes - Deferred income taxes are provided for the difference between the financial statement and income tax basis of assets and liabilities and carryforward items based on income tax laws and rates existing at the time the temporary differences are expected to reverse. Generally, the effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period that includes the enactment date of the rate change. For regulated companies, the effect on deferred tax assets and liabilities of a change in tax rates is recorded as regulatory assets and regulatory liabilities in the period that includes the enactment date, if, as a result of an action by a regulator, it is probable that the effect of the change in tax rates will be recovered from or returned to customers through future rates.

We utilize a more-likely-than-not recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position that is taken or expected to be taken in a tax return. We reflect penalties and interest as part of income tax expense as they become applicable for tax provisions that do not meet the more-likely-than-not recognition threshold and measurement attribute. During 2017, 2016 and 2015, our tax positions did not require an establishment of a material reserve.

We utilize the "with-and-without" approach for intra-period tax allocation for purposes of allocating total tax expense (or benefit) for the year among the various financial statement components.

We file numerous consolidated and separate income tax returns with federal tax authorities of the United States along with the tax authorities of several states. We are not under any United States federal audits or statute waivers at this time. See Note M for additional discussion of income taxes.

Asset Retirement Obligations - Asset retirement obligations represent legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or normal use of the asset. Certain of our natural gas gathering and processing, natural gas liquids and natural gas pipeline facilities are subject to agreements or regulations that give rise to our asset retirement obligations for removal or other disposition costs associated with retiring the assets in place upon the discontinued use of the assets. We recognize the fair value of a liability for an asset retirement obligation in the period when it is incurred if a reasonable estimate of the fair value can be made. We are not able to estimate reasonably the fair value of the asset retirement obligations for portions of our assets, primarily certain pipeline assets, because the settlement dates are indeterminable given our expected continued use of the assets with proper maintenance. We expect our pipeline assets, for which we are unable to estimate reasonably the fair value of the asset retirement obligation, will continue in operation as long as supply and demand for natural gas and natural gas liquids exists. Based on the widespread use of natural gas for heating and cooking activities for residential users and electric-power generation for commercial users, as well as use of natural gas liquids by the petrochemical industry, we expect supply and demand to exist for the foreseeable future.

For our assets that we are able to make an estimate, the fair value of the liability is added to the carrying amount of the associated asset, and this additional carrying amount is depreciated over the life of the asset. The liability is accreted at the end of each period through charges to operating expense. If the obligation is settled for an amount other than the carrying amount of the liability, we will recognize a gain or loss on settlement. The depreciation and accretion expense are immaterial to our Consolidated Financial Statements.

In accordance with long-standing regulatory treatment, we collect, through rates, the estimated costs of removal on certain regulated properties through depreciation expense, with a corresponding credit to accumulated depreciation and amortization. These removal costs collected through rates include legal and nonlegal removal obligations; however, the amounts collected in excess of the asset removal costs incurred are accounted for as a regulatory liability for financial reporting purposes. Historically, the regulatory authorities that have jurisdiction over our regulated operations have not required us to quantify this amount; rather, these costs are addressed prospectively in depreciation rates and are set in each general rate order. We have made an estimate of our regulatory liability using current rates since the last general rate order in each of our jurisdictions; however, for financial reporting purposes, significant uncertainty exists regarding the ultimate disposition of this regulatory liability pending, among other issues, clarification of regulatory intent. We continue to monitor regulatory requirements, and the liability may be adjusted as more information is obtained.

Contingencies - Our accounting for contingencies covers a variety of business activities, including contingencies for legal and environmental exposures. We accrue these contingencies when our assessments indicate that it is probable that a liability has been incurred or an asset will not be recovered and an amount can be estimated reasonably. We expense legal fees as incurred and base our legal liability estimates on currently available facts and our estimates of the ultimate outcome or resolution. Accruals for estimated losses from environmental remediation obligations generally are recognized no later than completion of a remediation feasibility study. Recoveries of environmental remediation costs from other parties are recorded as assets when their receipt is deemed probable. Our expenditures for environmental evaluation, mitigation, remediation and compliance to date have not been significant in relation to our financial position or results of operations, and our expenditures related to environmental matters had no material effect on earnings or cash flows during 2017, 2016 and 2015. Actual results may differ from our estimates resulting in an impact, positive or negative, on earnings. See Note O for additional discussion of contingencies.

Share-Based Payments - We expense the fair value of share-based payments net of estimated forfeitures. We estimate forfeiture rates based on historical forfeitures under our share-based payment plans.

Earnings per Common Share - Basic EPS is calculated based on the daily weighted-average number of shares of common stock outstanding during the period, vested restricted and performance units that have been deferred and share awards deferred under the compensation plan for nonemployee directors. Diluted EPS is calculated based on the daily weighted-average number of shares of common stock outstanding during the period plus potentially dilutive components. The dilutive components are calculated based on the dilutive effect for each quarter. For fiscal-year periods, the dilutive components for each quarter are averaged to arrive at the fiscal year-to-date dilutive component.

Reclassifications - Certain reclassifications have been made in the prior-year financial statements to conform to the current-year presentation.

Discontinued Operations - Beginning in 2017, the results of operations and financial position of our former energy services business are no longer reflected as discontinued operations in our Consolidated Financial Statements and Notes to the Consolidated Financial Statements, as they are not material.

Recently Issued Accounting Standards Update - Changes to GAAP are established by the FASB in the form of ASUs to the FASB Accounting Standards Codification. We consider the applicability and impact of all ASUs. ASUs not listed below were assessed and determined to be either not applicable or clarifications of ASUs listed below. The following tables provide a brief description of recent accounting pronouncements and our analysis of the effects on our financial statements:

Standard	Description	Date of Adoption	Effect on the Financial Statements or Other Significant Matters
Standards that were adopted			
ASU 2015-11, "Inventory (Topic 330): Simplifying the Measurement of Inventory"	The standard requires that inventory, excluding inventory measured using last-in, first-out (LIFO) or the retail inventory method, be measured at the lower of cost or net realizable value.	First quarter 2017	As a result of adopting this guidance, we updated our accounting policy for inventory valuation accordingly. The financial impact of adopting this guidance was not material.
ASU 2016-05, "Derivatives and Hedging (Topic 815): Effect of Derivative Contract Novations on Existing Hedge Accounting Relationships"	The standard clarifies that a change in the counterparty to a derivative instrument that has been designated as the hedging instrument under Topic 815 does not, in and of itself, require dedesignation of that hedging relationship provided that all other hedge accounting criteria continue to be met.	First quarter 2017	The impact of adopting this standard was not material.
ASU 2016-06, "Derivatives and Hedging (Topic 815): Contingent Put and Call Options in Debt Instruments"	The standard clarifies the requirements for assessing whether a contingent call (put) option that can accelerate the payment of principal on a debt instrument is clearly and closely related to its debt host.	First quarter 2017	The impact of adopting this standard was not material.
ASU 2016-09, "Compensation - Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting"	The standard provides simplified accounting for share-based payment transactions in relation to income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows.	First quarter 2017	As a result of adopting this guidance, we recorded an adjustment increasing beginning retained earnings and deferred tax assets in the first quarter 2017 of $73.4 million to recognize previously unrecognized cumulative excess tax benefits related to share-based payments on a modified retrospective basis. Beginning in January 2017, all share-based payment tax effects are recorded in earnings. The other effects of adopting this standard were not material.

Standard	Description	Date of Adoption	Effect on the Financial Statements or Other Significant Matters
Standards that are not yet adopted as of December 31, 2017			
ASU 2014-09, "Revenue from Contracts with Customers (Topic 606)"	The standard outlines the principles an entity must apply to measure and recognize revenue for entities that enter into contracts to provide goods or services to their customers. The core principle is that an entity should recognize revenue at an amount that reflects the consideration to which the entity expects to be entitled in exchange for transferring goods or services to a customer. The amendment also requires more extensive disaggregated revenue disclosures in interim and annual financial statements.	First quarter 2018	We adopted this standard on January 1, 2018, using the modified retrospective method. The cumulative effect of adopting the new standard was immaterial and related primarily to contract asset and liabilities described in our revenue recognition policies update. We do not expect adoption of the standard to be material to our operating income or net income; however, we expect a significant reduction to cost of sales and fuel in 2018 for amounts previously reported as services revenue in 2017 and prior periods, as described in our revenue recognition policies update. We have drafted required disclosures and expect to disaggregate revenues on a segment basis similar to our current presentation in Management's Discussion and Analysis. We expect our disclosure of unsatisfied performance obligations to relate primarily to firm transportation contracts. We do not expect a material contract asset balance and expect our contract liability balance to include storage contracts that have been prepaid by customers and contributions in aid of construction received from customers.
ASU 2016-01, "Financial Instruments-Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities"	The standard requires all equity investments, other than those accounted for using the equity method of accounting or those that result in consolidation of the investee, to be measured at fair value with changes in fair value recognized in net income, eliminates the available-for-sale classification for equity securities with readily determinable fair values and eliminates the cost method for equity investments without readily determinable fair values.	First quarter 2018	We do not have any equity investments classified as available-for-sale or accounted for using the cost method, therefore, we do not expect adoption of this standard to materially impact us.
ASU 2016-15, "Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments"	The standard clarifies the classification of certain cash receipts and cash payments on the statement of cash flows where diversity in practice has been identified.	First quarter 2018	We do not expect the adoption of this standard to materially impact us.
ASU 2017-07, "Compensation - Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost"	The standard requires the service cost component of net benefit cost to be reported in the same line item or items as other compensation costs from services rendered by the pertinent employees during the period. The other components of net benefit cost are required to be presented in the income statement separately from the service cost component and outside a subtotal of income from operations.	First quarter 2018	We do not expect the adoption of this standard to materially impact us.
ASU 2017-12, "Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities	The standard more closely aligns hedge accounting with companies' existing risk-management strategies by expanding the strategies eligible for hedge accounting, relaxing the timing requirements of hedge documentation and effectiveness assessments, permitting in certain cases, the use of qualitative assessments on an ongoing basis to assess hedge effectiveness, and requiring new disclosures and presentation.	First Quarter 2018	We adopted this standard in the first quarter 2018. At adoption, we recorded an immaterial cumulative-effect adjustment to the opening balance of retained earnings and other comprehensive income to eliminate the separate measurement of hedge ineffectiveness. We expect immaterial changes to disclosures as a result of adopting this standard.

Standard	Description	Date of Adoption	Effect on the Financial Statements or Other Significant Matters
Standards that are not yet adopted as of December 31, 2017 (*continued*)			
ASU 2016-02, "Leases (Topic 842)"	The standard requires the recognition of lease assets and lease liabilities by lessees for those leases classified as operating leases under previous GAAP. It also requires qualitative disclosures along with specific quantitative disclosures by lessees and lessors to meet the objective of enabling users of financial statements to assess the amount, timing and uncertainty of cash flows arising from leases.	First quarter 2019	We are evaluating our current leases and other contracts that may be considered leases under the new standard and the impact on our internal controls, accounting policies and financial statements and disclosures. Our evaluation process includes creating a database of our existing leases and identifying a central group to track and account for lease activity, which is ongoing. We are developing internal controls to ensure the completeness and accuracy of the data. Due to this ongoing work, we cannot yet determine the quantitative impact, but adoption of the standard will result in the recognition of right of use assets and lease liabilities not previously recorded that will be presented on our Consolidated Balance Sheet under Topic 842 and will require disclosure in our footnotes. We are also monitoring recent exposure drafts and clarifications issued by the FASB.
ASU 2018-02, "Income Statement - Reporting Comprehensive Income (Topic 220): Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income"	This standard allows a reclassification from accumulated other comprehensive income to retained earnings for stranded tax effects resulting from the Tax Cuts and Jobs Act.	First quarter 2019	We are evaluating the impact of this standard on us.
ASU 2016-13, "Financial Instruments - Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments"	The standard requires a financial asset (or a group of financial assets) measured at amortized cost basis to be presented net of the allowance for credit losses to reflect the net carrying value at the amount expected to be collected on the financial asset; and the initial allowance for credit losses for purchased financial assets, including available-for-sale debt securities, to be added to the purchase price rather than being reported as a credit loss expense.	First quarter 2020	We do not expect the adoption of this standard to materially impact us.
ASU 2017-04, "Intangibles-Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment"	The standard simplifies the subsequent measurement of goodwill by eliminating the requirement to calculate the implied fair value of goodwill under step 2. Instead, an entity will recognize an impairment charge for the amount by which the carrying amount exceeds the reporting unit's fair value. The standard does not change step zero or step 1 assessments.	First quarter 2020	We do not expect the adoption of this standard to materially impact us.

B. ACQUISITION OF ONEOK PARTNERS

On June 30, 2017, we completed the acquisition of all of the outstanding common units of ONEOK Partners that we did not already own at a fixed exchange ratio of 0.985 of a share of our common stock for each ONEOK Partners common unit. We issued 168.9 million shares of our common stock to third-party common unitholders of ONEOK Partners in exchange for all of the 171.5 million outstanding common units of ONEOK Partners that we previously did not own. No fractional shares were issued in the Merger Transaction, and ONEOK Partners common unitholders instead received cash in lieu of fractional shares. As a result of the completion of the Merger Transaction, common units of ONEOK Partners are no longer publicly traded.

As we controlled ONEOK Partners and continue to control ONEOK Partners after the Merger Transaction, the change in our ownership interest was accounted for as an equity transaction, and no gain or loss was recognized in our Consolidated Statements of Income resulting from the Merger Transaction. The Merger Transaction was a taxable exchange to the ONEOK Partners unitholders resulting in a book/tax difference in the basis of the underlying assets acquired. We recorded a deferred tax asset of $2.1 billion, computed as the net of the equity value exchanged of $8.8 billion and noncontrolling interests of $3.0 billion at a tax rate of 37 percent, based on a tax allocation of the transaction value.

Prior to June 30, 2017, we and our subsidiaries owned all of the general partner interest, which included incentive distribution rights, and a portion of the limited partner interest, which together represented a 41.2 percent ownership interest in ONEOK Partners. The equity interests in ONEOK Partners (which are consolidated in our financial statements) that were owned by the public until June 30, 2017, are reflected in “Noncontrolling interests” in our accompanying Consolidated Balance Sheet as of December 31, 2016. The earnings of ONEOK Partners that are attributed to its units held by the public until June 30, 2017, are reported as “Net income attributable to noncontrolling interest” in our accompanying Consolidated Statements of Income. Our general partner incentive distribution rights effectively terminated at the closing of the Merger Transaction.

Effective with the close of the Merger Transaction, we, ONEOK Partners and the Intermediate Partnership issued, to the extent not already in place, guarantees of the indebtedness of ONEOK and ONEOK Partners.

Supplemental Cash Flow Information - Our noncash balance sheet activity related to the Merger Transaction is as follows (in millions):

Common stock	$	1.7
Paid-in capital	$	5,228.6
Accumulated other comprehensive loss	$	(40.3)
Noncontrolling interests in consolidated subsidiaries	$	(3,043.5)
Deferred income taxes	$	(2,146.5)

C. FAIR VALUE MEASUREMENTS

Recurring Fair Value Measurements - The following tables set forth our recurring fair value measurements for the periods indicated:

	December 31, 2017					
	Level 1	**Level 2**	**Level 3**	**Total - Gross**	**Netting (a)**	**Total - Net (b)**
			(*Thousands of dollars*)			
Derivative assets						
Commodity contracts						
Financial contracts	**$ 4,252**	**$ —**	**$ 20,203**	**$ 24,455**	**$ (24,455)**	**$ —**
Interest-rate contracts	**—**	**49,960**	**—**	**49,960**	**—**	**49,960**
Total derivative assets	**$ 4,252**	**$ 49,960**	**$ 20,203**	**$ 74,415**	**$ (24,455)**	**$ 49,960**
Derivative liabilities						
Commodity contracts						
Financial contracts	**$ (5,708)**	**$ —**	**$ (48,260)**	**$ (53,968)**	**$ 53,936**	**$ (32)**
Physical contracts	**—**	**—**	**(4,781)**	**(4,781)**	**—**	**(4,781)**
Total derivative liabilities	**$ (5,708)**	**$ —**	**$ (53,041)**	**$ (58,749)**	**$ 53,936**	**$ (4,813)**

(a) - Derivative assets and liabilities are presented in our Consolidated Balance Sheets on a net basis. We net derivative assets and liabilities when a legally enforceable master-netting arrangement exists between the counterparty to a derivative contract and us. At December 31, 2017, we held no cash and posted $49.7 million of cash with various counterparties, including $29.5 million of cash collateral that is offsetting derivative net liability positions under master-netting arrangements in the table above. The remaining $20.2 million of cash collateral in excess of derivative net liability positions is included in other current assets in our Consolidated Balance Sheets.
(b) - Included in other current assets, other assets or other current liabilities in our Consolidated Balance Sheets.

	December 31, 2016											
	Level 1		Level 2		Level 3		Total - Gross		Netting (a)		Total - Net (b)	
	(*Thousands of dollars*)											
Derivative assets												
Commodity contracts												
Financial contracts	$	1,147	$	—	$	4,564	$	5,711	$	(4,760)	$	951
Interest-rate contracts		—		47,457		—		47,457		—		47,457
Total derivative assets	$	1,147	$	47,457	$	4,564	$	53,168	$	(4,760)	$	48,408
Derivative liabilities												
Commodity contracts												
Financial contracts	$	(31,458)	$	—	$	(24,861)	$	(56,319)	$	56,319	$	—
Physical contracts		—		—		(3,022)		(3,022)		—		(3,022)
Interest-rate contracts		—		(12,795)		—		(12,795)		—		(12,795)
Total derivative liabilities	$	(31,458)	$	(12,795)	$	(27,883)	$	(72,136)	$	56,319	$	(15,817)

a) - Derivative assets and liabilities are presented in our Consolidated Balance Sheets on a net basis. We net derivative assets and liabilities when a legally enforceable master-netting arrangement exists between the counterparty to a derivative contract and us. At December 31, 2016, we held no cash and posted $67.7 million of cash with various counterparties, including $51.6 million of cash collateral that is offsetting derivative net liability positions under master-netting arrangements in the table above. The remaining $16.1 million of cash collateral in excess of derivative net liability positions is included in other current assets in our Consolidated Balance Sheets.
(b) - Included in other current assets, other assets or other current liabilities in our Consolidated Balance Sheets.

The following table sets forth a reconciliation of our Level 3 fair value measurements for the periods indicated:

	Years Ended December 31,			
Derivative Assets (Liabilities)		**2017**		**2016**
	(*Thousands of dollars*)			
Net assets (liabilities) at beginning of period	**$**	**(23,319)**	$	7,331
Total realized/unrealized gains (losses):				
Included in earnings (a)		**212**		(320)
Included in other comprehensive income (loss)		**(9,731)**		(30,330)
Net assets (liabilities) at end of period	**$**	**(32,838)**	$	(23,319)

(a) - Included in commodity sales revenues in our Consolidated Statements of Income.

Realized/unrealized gains (losses) include the realization of our derivative contracts through maturity. During the years ended December 31, 2017 and 2016, gains or losses included in earnings attributable to the change in unrealized gains or losses relating to assets and liabilities still held at the end of each reporting period were not material.

We recognize transfers into and out of the levels in the fair value hierarchy as of the end of each reporting period. During the years ended December 31, 2017 and 2016, there were no transfers between levels.

Other Financial Instruments - The approximate fair value of cash and cash equivalents, accounts receivable, accounts payable and short-term borrowings is equal to book value due to the short-term nature of these items. Our cash and cash equivalents are comprised of bank and money market accounts and are classified as Level 1. Our short-term borrowings are classified as Level 2 since the estimated fair value of the short-term borrowings can be determined using information available in the commercial paper market.

The estimated fair value of our consolidated long-term debt, including current maturities, was $9.3 billion and $8.8 billion at December 31, 2017 and 2016, respectively. The book value of our consolidated long-term debt, including current maturities, was $8.5 billion and $8.3 billion at December 31, 2017 and 2016, respectively. The estimated fair value of the aggregate of our and ONEOK Partners' senior notes outstanding was determined using quoted market prices for similar issues with similar terms and maturities. The estimated fair value of our consolidated long-term debt is classified as Level 2.

D. RISK-MANAGEMENT AND HEDGING ACTIVITIES USING DERIVATIVES

Risk-Management Activities - We are sensitive to changes in natural gas, crude oil and NGL prices, principally as a result of contractual terms under which these commodities are processed, purchased and sold. We are also subject to the risk of interest-rate fluctuation in the normal course of business. We use physical-forward purchases and sales and financial derivatives to secure a certain price for a portion of our natural gas, condensate and NGL products; to reduce our exposure to commodity price and interest-rate fluctuations; and to achieve more predictable cash flows. We follow established policies and procedures to assess risk and approve, monitor and report our risk-management activities. We have not used these instruments for trading purposes.

Commodity price risk - Commodity price risk refers to the risk of loss in cash flows and future earnings arising from adverse changes in the price of natural gas, NGLs and condensate. We use the following commodity derivative instruments to reduce the near-term commodity price risk associated with a portion of the forecasted sales of these commodities:

- Futures contracts - Standardized contracts to purchase or sell natural gas and crude oil for future delivery or settlement under the provisions of exchange regulations;
- Forward contracts - Nonstandardized commitments between two parties to purchase or sell natural gas, crude oil or NGLs for future physical delivery. These contracts are typically nontransferable and can only be canceled with the consent of both parties;
- Swaps - Exchange of one or more payments based on the value of one or more commodities. These instruments transfer the financial risk associated with a future change in value between the counterparties of the transaction, without also conveying ownership interest in the asset or liability; and
- Options - Contractual agreements that give the holder the right, but not the obligation, to buy or sell a fixed quantity of a commodity at a fixed price within a specified period of time. Options may either be standardized and exchange-traded or customized and nonexchange-traded.

We may also use other instruments including collars to mitigate commodity price risk. A collar is a combination of a purchased put option and a sold call option, which places a floor and a ceiling price for commodity sales being hedged.

In our Natural Gas Gathering and Processing segment, we are exposed to commodity price risk as a result of retaining a portion of the commodity sales proceeds associated with our POP with fee contracts. Under certain POP with fee contracts, our fees and POP percentage may increase or decrease if production volumes, delivery pressures or commodity prices change relative to specified thresholds. We also are exposed to basis risk between the various production and market locations where we buy and sell commodities. As part of our hedging strategy, we use the previously described commodity derivative financial instruments and physical-forward contracts to reduce the impact of price fluctuations related to natural gas, NGLs and condensate.

In our Natural Gas Liquids segment, we are exposed to location price differential risk, primarily as a result of the relative value of NGL purchases at one location and sales at another location. We are also exposed to commodity price risk resulting from the relative values of the various NGL products to each other, NGLs in storage and the relative value of NGLs to natural gas. We utilize physical-forward contracts and commodity derivative financial instruments to reduce the impact of price fluctuations related to NGLs.

In our Natural Gas Pipelines segment, we are exposed to commodity price risk because our intrastate and interstate natural gas pipelines retain natural gas from our customers for operations or as part of our fee for services provided. When the amount of natural gas consumed in operations by these pipelines differs from the amount provided by our customers, our pipelines must buy or sell natural gas, or store or use natural gas from inventory, which can expose this segment to commodity price risk depending on the regulatory treatment for this activity. To the extent that commodity price risk in our Natural Gas Pipelines segment is not mitigated by fuel cost-recovery mechanisms, we may use physical-forward sales or purchases to reduce the impact of price fluctuations related to natural gas. At December 31, 2017 and 2016, there were no financial derivative instruments with respect to our natural gas pipeline operations.

Interest-rate risk - We manage interest-rate risk through the use of fixed-rate debt, floating-rate debt and interest-rate swaps. Interest-rate swaps are agreements to exchange interest payments at some future point based on specified notional amounts. In July 2017, we settled $400 million of our forward-starting interest-rate swaps upon the completion of our underwritten public offering of $1.2 billion senior unsecured notes and $500 million of our interest-rate swaps used to hedge our LIBOR-based interest payments. In September 2017, we entered into forward-starting interest-rate swaps with notional amounts totaling $500 million to hedge the variability of interest payments on a portion of our forecasted debt issuances that may result from changes in the benchmark interest rate before the debt is issued.

At December 31, 2017 and 2016, we had forward-starting interest-rate swaps with notional amounts totaling $1.3 billion and $1.2 billion, respectively, to hedge the variability of interest payments on a portion of our forecasted debt issuances and interest-rate swaps with notional amounts totaling $500 million and $1.0 billion, respectively, to hedge the variability of our LIBOR-based interest payments. All of our interest-rate swaps are designated as cash flow hedges.

In January 2018, we settled the remaining $500 million of our interest-rate swaps used to hedge our LIBOR-based interest payments.

Fair Values of Derivative Instruments - The following table sets forth the fair values of our derivative instruments presented on a gross basis for the periods indicated:

	Location in our Consolidated Balance Sheets	December 31, 2017 Assets	December 31, 2017 (Liabilities)	December 31, 2016 Assets	December 31, 2016 (Liabilities)
		(*Thousands of dollars*)			
Derivatives designated as hedging instruments					
Commodity contracts					
Financial contracts	Other current assets/other current liabilities	**$ 16,978**	**$ (42,819)**	$ 1,155	$ (49,938)
	Other assets/other deferred credits	**—**	**(3,838)**	210	(2,142)
Physical contracts	Other current liabilities	**—**	**(4,781)**	—	(3,022)
Interest-rate contracts	Other current assets/other current liabilities	**1,330**	**—**	—	(12,795)
	Other assets	**48,630**	**—**	47,457	—
Total derivatives designated as hedging instruments		**66,938**	**(51,438)**	48,822	(67,897)
Derivatives not designated as hedging instruments					
Commodity contracts					
Financial contracts	Other current assets/other current liabilities	**7,477**	**(7,311)**	4,346	(4,239)
Total derivatives not designated as hedging instruments		**7,477**	**(7,311)**	4,346	(4,239)
Total derivatives		**$ 74,415**	**$ (58,749)**	$ 53,168	$ (72,136)

Notional Quantities for Derivative Instruments - The following table sets forth the notional quantities for derivative instruments held for the periods indicated:

	Contract Type	December 31, 2017 Purchased/ Payor	December 31, 2017 Sold/ Receiver	December 31, 2016 Purchased/ Payor	December 31, 2016 Sold/ Receiver
Derivatives designated as hedging instruments:					
Cash flow hedges					
Fixed price					
-Natural gas (*Bcf*)	Futures and swaps	**—**	**(24.5)**	—	(38.4)
-Natural gas (*Bcf*)	Put options	**—**	**—**	49.5	—
-Crude oil and NGLs (*MMBbl*)	Futures, forwards and swaps	**3.5**	**(11.1)**	—	(3.6)
Basis					
-Natural gas (*Bcf*)	Futures and swaps	**—**	**(24.5)**	—	(38.4)
Interest-rate contracts (*Millions of dollars*)	Swaps	**$ 1,750.0**	**$ —**	$ 2,150.0	$ —
Derivatives not designated as hedging instruments:					
Fixed price					
-Natural gas (*Bcf*)	Futures and swaps	**—**	**—**	0.4	—
-NGLs (*MMBbl*)	Futures, forwards and swaps	**0.8**	**(0.8)**	0.5	(0.7)
Basis					
-Natural gas (*Bcf*)	Futures and swaps	**—**	**—**	0.4	—

These notional amounts are used to summarize the volume of financial instruments; however, they do not reflect the extent to which the positions offset one another and, consequently, do not reflect our actual exposure to market or credit risk.

Cash Flow Hedges - At December 31, 2017, our Consolidated Balance Sheet reflected a net loss of $188.5 million in accumulated other comprehensive loss. The portion of accumulated other comprehensive loss attributable to our commodity derivative financial instruments is an unrealized loss of $21.7 million net of tax, which is expected to be realized within the next two years as the forecasted transactions affect earnings. If commodity prices remain at current levels, we will realize approximately $19.3 million in net losses, net of tax, over the next 12 months and approximately $2.4 million in net losses, net of tax, thereafter. The amount deferred in accumulated other comprehensive loss attributable to our settled interest-rate swaps is a loss of $87.6 million net of tax, which will be recognized over the life of the long-term, fixed-rate debt, including losses of $14.0 million, net of tax, that will be reclassified into earnings during the next 12 months as the hedged items affect earnings. The remaining amounts in accumulated other comprehensive loss are attributable primarily to forward-starting interest-rate swaps with future settlement dates, which are expected to be amortized to interest expense over the life of long-term, fixed-rate debt upon issuance of the debt.

The following table sets forth the unrealized effect of cash flow hedges recognized in other comprehensive income (loss) for the periods indicated:

Derivatives in Cash Flow Hedging Relationships	Years Ended December 31, 2017	2016	2015
	(Thousands of dollars)		
Commodity contracts	**$ (40,577)**	$ (78,513)	$ 70,065
Interest-rate contracts	**163**	42,761	(22,565)
Total unrealized gain (loss) recognized in other comprehensive income (loss) on derivatives (effective portion)	**$ (40,414)**	$ (35,752)	$ 47,500

The following table sets forth the effect of cash flow hedges in our Consolidated Statements of Income for the periods indicated:

Derivatives in Cash Flow Hedging Relationships	Location of Gain (Loss) Reclassified from Accumulated Other Comprehensive Loss into Net Income (Effective Portion)	Years Ended December 31, 2017	2016	2015
		(Thousands of dollars)		
Commodity contracts	Commodity sales revenues	**$ (69,561)**	$ 26,422	$ 81,089
Interest-rate contracts	Interest expense	**(21,025)**	(19,215)	(17,565)
Total gain (loss) reclassified from accumulated other comprehensive loss into net income on derivatives (effective portion)		**$ (90,586)**	$ 7,207	$ 63,524

Credit Risk - We monitor the creditworthiness of our counterparties and compliance with policies and limits established by our Risk Oversight and Strategy Committee. We maintain credit policies with regard to our counterparties that we believe minimize overall credit risk. These policies include an evaluation of potential counterparties' financial condition (including credit ratings, bond yields and credit default swap rates), collateral requirements under certain circumstances and the use of standardized master-netting agreements that allow us to net the positive and negative exposures associated with a single counterparty. We have counterparties whose credit is not rated, and for those customers, we use internally developed credit ratings.

From time to time, we may enter into financial derivative instruments that contain provisions that require us to maintain an investment-grade credit rating from S&P and/or Moody's. If our credit ratings on our senior unsecured long-term debt were to decline below investment grade, the counterparties to the derivative instruments could request collateralization on derivative instruments in net liability positions. There were no financial derivative instruments with contingent features related to credit risk at December 31, 2017.

The counterparties to our derivative contracts consist primarily of major energy companies, financial institutions and commercial and industrial end users. This concentration of counterparties may affect our overall exposure to credit risk, either positively or negatively, in that the counterparties may be affected similarly by changes in economic, regulatory or other conditions. Based on our policies, exposures, credit and other reserves, we do not anticipate a material adverse effect on our financial position or results of operations as a result of counterparty nonperformance.

At December 31, 2017, the net credit exposure from our derivative assets is with investment-grade companies in the financial services sector.

E. PROPERTY, PLANT AND EQUIPMENT

The following table sets forth our property, plant and equipment by property type, for the periods indicated:

	Estimated Useful Lives (Years)	December 31, 2017	December 31, 2016
		(Thousands of dollars)	
Nonregulated			
Gathering pipelines and related equipment	5 to 40	**$ 3,613,344**	$ 3,352,963
Processing and fractionation and related equipment	3 to 40	**3,873,709**	3,831,966
Storage and related equipment	3 to 54	**604,656**	558,695
Transmission pipelines and related equipment	5 to 54	**700,455**	689,804
General plant and other	2 to 60	**504,610**	487,559
Construction work in process	—	**362,253**	371,628
Regulated			
Storage and related equipment	5 to 25	**12,486**	13,524
Natural gas transmission pipelines and related equipment	5 to 77	**1,406,780**	1,345,740
Natural gas liquids transmission pipelines and related equipment	5 to 88	**4,340,428**	4,309,341
General plant and other	2 to 50	**57,902**	54,643
Construction work in process	—	**83,044**	62,634
Property, plant and equipment		**15,559,667**	15,078,497
Accumulated depreciation and amortization - nonregulated		**(1,888,010)**	(1,641,490)
Accumulated depreciation and amortization - regulated		**(973,531)**	(865,604)
Net property, plant and equipment		**$ 12,698,126**	$ 12,571,403

The average depreciation rates for our regulated property are set forth, by segment, in the following table for the periods indicated:

	Years Ended December 31,		
	2017	**2016**	**2015**
Natural Gas Liquids	**1.9%**	1.9%	1.9%
Natural Gas Pipelines	**2.1%**	2.1%	2.1%

We incurred costs for construction work in process that had not been paid at December 31, 2017, 2016 and 2015, of $92.4 million, $83.0 million and $115.7 million, respectively. Such amounts are not included in capital expenditures (less AFUDC and capitalized interest) on the Consolidated Statements of Cash Flows.

Impairment Charges - The following table sets forth impairment charges on our long-lived assets for the periods indicated:

	Years Ended December 31,		
	2017	**2016**	**2015**
Natural Gas Gathering and Processing	**$ 16.0**	$ —	$ 73.7
Natural Gas Liquids	**—**	—	10.0
Total Impairment of long-lived assets	**$ 16.0**	$ —	$ 83.7

In the third quarter 2017, following a review of nonstrategic assets for potential divestiture, we recorded $16.0 million of noncash impairment charges related to certain nonstrategic gathering and processing assets located in North Dakota.

In 2015, we recorded a $63.5 million noncash impairment charge to long-lived assets in our Natural Gas Gathering and Processing segment related to our wholly owned coal-bed methane natural gas gathering system, which we shut down in 2016. We also recorded noncash impairment charges of $20.2 million for previously idled assets in our Natural Gas Gathering and Processing and Natural Gas Liquids segments, as our expectation for future use of these assets changed.

F. GOODWILL AND INTANGIBLE ASSETS

Goodwill - The following table sets forth our goodwill, by segment, for the periods indicated:

	December 31, 2017	December 31, 2016
	(*Thousands of dollars*)	
Natural Gas Gathering and Processing	**$ 153,404**	$ 122,291
Natural Gas Liquids	**371,217**	268,544
Natural Gas Pipelines	**156,479**	134,700
Total goodwill	**$ 681,100**	$ 525,535

As a result of the Merger Transaction, we are entitled to receive all available ONEOK Partners cash. Our incentive distribution rights effectively terminated at the close of the Merger Transaction. As a result, the $155.6 million carrying value of the indefinite-lived intangible asset associated with our incentive distribution rights was reclassified to goodwill and allocated among our business segments.

Intangible Assets - Our intangible assets relate primarily to contracts acquired through acquisitions in our Natural Gas Gathering and Processing and Natural Gas Liquids segments, which are being amortized over periods of 20 to 40 years. Amortization expense for intangible assets was $11.9 million in 2017, 2016 and 2015, and the aggregate amortization expense for each of the next five years is estimated to be approximately $11.9 million. The following table reflects the gross carrying amount and accumulated amortization of intangible assets for the periods presented:

	December 31, 2017	December 31, 2016
	(*Thousands of dollars*)	
Gross intangible assets	**$ 426,068**	$ 581,633
Accumulated amortization	**(113,708)**	(101,809)
Net intangible assets	**$ 312,360**	$ 479,824

G. DEBT

The following table sets forth our consolidated debt for the periods indicated:

	December 31, 2017	December 31, 2016
	(Thousands of dollars)	
ONEOK		
Commercial paper outstanding, bearing a weighted-average interest rate of 2.23% (a)	**$ 614,673**	$ —
Senior unsecured obligations:		
$700,000 at 4.25% due February 2022	**547,397**	547,397
$500,000 at 7.5% due September 2023	**500,000**	500,000
$500,000 at 4.0% due July 2027	**500,000**	—
$100,000 at 6.5% due September 2028	**—**	87,126
$100,000 at 6.875% due September 2028	**100,000**	100,000
$400,000 at 6.0% due June 2035	**400,000**	400,000
$700,000 at 4.95% due July 2047	**700,000**	—
ONEOK Partners		
Commercial paper outstanding (a)	**—**	1,110,277
Senior unsecured obligations:		
$400,000 at 2.0% due October 2017	**—**	400,000
$425,000 at 3.2% due September 2018	**425,000**	425,000
$1,000,000 term loan, at 2.87% and 2.04%, respectively, due January 2019 (b)	**500,000**	1,000,000
$500,000 at 8.625% due March 2019	**500,000**	500,000
$300,000 at 3.8% due March 2020	**300,000**	300,000
$900,000 at 3.375 % due October 2022	**900,000**	900,000
$425,000 at 5.0 % due September 2023	**425,000**	425,000
$500,000 at 4.9 % due March 2025	**500,000**	500,000
$600,000 at 6.65% due October 2036	**600,000**	600,000
$600,000 at 6.85% due October 2037	**600,000**	600,000
$650,000 at 6.125% due February 2041	**650,000**	650,000
$400,000 at 6.2% due September 2043	**400,000**	400,000
Guardian Pipeline		
Weighted average 7.85% due December 2022	**36,607**	44,257
Total debt	**9,198,677**	9,489,057
Unamortized portion of terminated swaps	**18,468**	20,186
Unamortized debt issuance costs and discounts	**(78,193)**	(68,320)
Current maturities of long-term debt	**(432,650)**	(410,650)
Short-term borrowings (c)	**(614,673)**	(1,110,277)
Long-term debt	**$ 8,091,629**	$ 7,919,996

(a) - In July 2017, the commercial paper outstanding under the ONEOK Partners commercial paper program was repaid as it matured with a combination of proceeds from new issuances from ONEOK's recently established $2.5 billion commercial paper program, cash on hand and proceeds from our July 2017 $1.2 billion senior notes issuance. The $2.4 billion ONEOK Partners commercial paper program was terminated in July 2017.
(b) - The remaining $500 million of the Term Loan Agreement was repaid in January 2018.
(c) - Individual issuances of commercial paper under our commercial paper program generally mature in 90 days or less. These issuances are supported by and reduce the borrowing capacity under the $2.5 Billion Credit Agreement.

Debt Guarantees - Effective June 30, 2017, with the Merger Transaction, we, ONEOK Partners and the Intermediate Partnership issued, to the extent not already in place, guarantees of the indebtedness of ONEOK and ONEOK Partners.

$2.5 Billion Credit Agreement - In April 2017, we entered into the $2.5 Billion Credit Agreement with a syndicate of banks, which became effective June 30, 2017, with the close of the Merger Transaction and the terminations of the ONEOK Credit Agreement and ONEOK Partners Credit Agreement. The $2.5 Billion Credit Agreement is a $2.5 billion revolving credit facility and contains certain financial, operational and legal covenants. Among other things, these covenants include maintaining a ratio of indebtedness to adjusted EBITDA (EBITDA, as defined in our $2.5 Billion Credit Agreement, adjusted for all noncash charges and increased for projected EBITDA from certain lender-approved capital expansion projects) of no more than 5.75 to 1 at December 31, 2017; 5.5 to 1 for the subsequent two quarters; and 5.0 to 1 thereafter. Once the covenant decreases to 5.0 to 1, if we consummate one or more acquisitions in which the aggregate purchase is $25 million or more, the allowable ratio of indebtedness to adjusted EBITDA will increase to 5.5 to 1 for the quarter in which the acquisition is completed and the two following quarters.

The $2.5 Billion Credit Agreement includes a $100 million sublimit for the issuance of standby letters of credit and a $200 million sublimit for swingline loans. Under the terms of the $2.5 Billion Credit Agreement, we may request an increase in the size of the facility to an aggregate of $3.5 billion by either commitments from new lenders or increased commitments from existing lenders. The $2.5 Billion Credit Agreement contains provisions for an applicable margin rate and an annual facility fee, both of which adjust with changes in our credit ratings. Based on our current credit ratings, borrowings, if any, will accrue at LIBOR plus 110 basis points, and the annual facility fee is 15 basis points. We have the option to request two one-year extensions, subject to lender approval, which may be used for working capital, capital expenditures, acquisitions and mergers, the issuance of letters of credit and for other general corporate purposes. At December 31, 2017, our ratio of indebtedness to adjusted EBITDA was 4.5 to 1, and we were in compliance with all covenants under the $2.5 Billion Credit Agreement.

At December 31, 2017, we had $15.8 million of letters of credit issued and no borrowings outstanding under the $2.5 Billion Credit Agreement. At December 31, 2016, ONEOK had $1.1 million letters of credit issued and no borrowings outstanding under the ONEOK Credit Agreement, and ONEOK Partners had $14.0 million of letters of credit issued and no borrowings outstanding under the ONEOK Partners Credit Agreement.

Senior Unsecured Obligations - All notes are senior unsecured obligations, ranking equally in right of payment with all of our existing and future unsecured senior indebtedness, and are structurally subordinate to any of the existing and future debt and other liabilities of any nonguarantor subsidiaries.

Issuances - In July 2017, we completed an underwritten public offering of $1.2 billion senior unsecured notes consisting of $500 million, 4.0 percent senior notes due 2027, and $700 million, 4.95 percent senior notes due 2047. The net proceeds, after deducting underwriting discounts, commissions and offering expenses, were $1.2 billion. The proceeds were used for general corporate purposes, which included repayment of existing indebtedness and capital expenditures.

In 2016, ONEOK Partners entered into the $1.0 billion senior unsecured Term Loan Agreement with a syndicate of banks maturing in 2019, bears interest at LIBOR plus 130 basis points based on our current credit ratings, allows prepayment without penalty or premium and contains substantially the same covenants as our $2.5 Billion Credit Agreement. As of January 2018, all amounts outstanding under the Term Loan Agreement have been repaid. See “repayments” section below.

In August 2015, we completed an underwritten public offering of $500 million, 7.5 percent senior notes due 2023. The net proceeds, after deducting underwriting discounts, commissions and other expenses, were $487.1 million. We used the proceeds together with cash on hand to purchase $650 million of additional common units from ONEOK Partners.

In March 2015, ONEOK Partners completed an underwritten public offering of $800 million of senior notes, consisting of $300 million, 3.8 percent senior notes due 2020, and $500 million, 4.9 percent senior notes due 2025. The net proceeds, after deducting underwriting discounts, commissions and offering expenses, were $792.3 million and were used to repay amounts outstanding under its commercial paper program and for general partnership purposes.

Repayments - We repaid $500 million in both January 2018 and July 2017 on the Term Loan Agreement due 2019 with a combination of cash on hand and short-term borrowings. As of January 2018, all amounts outstanding under the Term Loan Agreement have been repaid.

In September 2017, we repaid ONEOK Partners’ $400 million, 2.0 percent senior notes due in October 2017 with a combination of cash on hand and short-term borrowings.

In July 2017, we redeemed our 6.5 percent senior notes due 2028 at a redemption price of $87.0 million, including the outstanding principal amount, plus accrued and unpaid interest, with cash on hand.

In October 2016, ONEOK Partners repaid its $450 million, 6.15 percent senior notes at maturity with a combination of cash on hand and short-term borrowings.

The aggregate maturities of long-term debt outstanding as of December 31, 2017, for the years 2018 through 2022 are shown below:

	Senior Notes	Guardian Pipeline	Total
2018	$ 425.0	$ 7.7	$ 432.7
2019 (a)	$ 1,000.0	$ 7.7	$ 1,007.7
2020	$ 300.0	$ 7.7	$ 307.7
2021	$ —	$ 7.7	$ 7.7
2022	$ 1,447.4	$ 5.8	$ 1,453.2

(a) $500 million of the $1.0 billion maturing in 2019 relates to the Term Loan Agreement, which was repaid in January 2018.

ONEOK covenants - The indentures governing ONEOK's 6.875 percent senior notes due 2028 include an event of default upon acceleration of other indebtedness of $15 million or more, and the indentures governing the senior notes due 2022, 2023, 2027, 2035 and 2047 include an event of default upon the acceleration of other indebtedness of $100 million or more. Such events of default would entitle the trustee or the holders of 25 percent in aggregate principal amount of the outstanding senior notes due 2022, 2023, 2027, 2028, 2035 and 2047 to declare those senior notes immediately due and payable in full. The indenture for the notes due 2023 also contains a provision that allows the holders of the notes to require ONEOK to offer to repurchase all or any part of their notes if a change of control and a credit rating downgrade occur at a purchase price of 101 percent of the principal amount, plus accrued and unpaid interest, if any.

ONEOK may redeem its senior notes, in whole or in part, at any time prior to their maturity at a redemption price equal to the principal amount, plus accrued and unpaid interest and a make-whole premium. ONEOK may redeem the remaining balance of its senior notes due 2022, 2023, 2027 and 2047 at a redemption price equal to the principal amount, plus accrued and unpaid interest, starting three to six months before the maturity date as stipulated in the respective contract terms. ONEOK's senior notes are senior unsecured obligations, ranking equally in right of payment with all of ONEOK's existing and future unsecured senior indebtedness.

ONEOK Partners covenants - ONEOK Partners' senior notes are governed by an indenture containing covenants including, among other provisions, limitations on ONEOK Partners' ability to place liens on its property or assets and to sell and lease back its property. The indenture includes an event of default upon acceleration of other indebtedness of $100 million or more. Such events of default would entitle the trustee or the holders of 25 percent in aggregate principal amount of any of ONEOK Partners' outstanding senior notes to declare those notes immediately due and payable in full.

The senior notes may be redeemed, in whole or in part, at any time prior to their maturity at a redemption price equal to the principal amount, plus accrued and unpaid interest and a make-whole premium. The senior notes due 2018, 2020, 2022, 2023, 2025, 2041 and 2043 may be redeemed at a redemption price equal to the principal amount, plus accrued and unpaid interest, starting one to six months before their maturity dates as stipulated in the respective contract terms.

Guardian Pipeline Senior Notes - These senior notes were issued under a master shelf agreement dated November 8, 2001, with certain financial institutions. Principal payments are due quarterly through 2022. Guardian Pipeline's senior notes contain financial covenants that require the maintenance of certain financial ratios as defined in the master shelf agreement based on Guardian Pipeline's financial position and results of operations. Upon any breach of these covenants, all amounts outstanding under the master shelf agreement may become due and payable immediately. At December 31, 2017, Guardian Pipeline was in compliance with its financial covenants.

Other - We amortize premiums, discounts and expenses incurred in connection with the issuance of long-term debt consistent with the terms of the respective debt instrument.

H. EQUITY

Ownership Interest in ONEOK Partners - At December 31, 2016, we and our subsidiaries owned all of the general partner interest, which included incentive distribution rights, and a portion of the limited partner interest, which together represented a 41.2 percent ownership interest in ONEOK Partners. The portion of ONEOK Partners that we did not own is reflected in our 2016 Consolidated Balance Sheet under the caption "Noncontrolling interests" along with the 20 percent of WTLPG that we do not own. At December 31, 2017, the caption "Noncontrolling interests" on our Consolidated Balance Sheet reflects only the 20 percent of WTLPG that we do not own.

Series A and B Convertible Preferred Stock - There are no shares of Series A or Series B Preferred Stock currently issued or outstanding.

Series E Preferred Stock - In April 2017, through a wholly owned subsidiary, we contributed 20,000 shares of newly issued Series E Preferred Stock, having an aggregate value of $20 million, to the Foundation for use in charitable and nonprofit causes. The contribution was recorded as a $20 million noncash expense in 2017 and is included in other expense in our Consolidated Statements of Income.

Dividends - Holders of our common stock share equally in any dividend declared by our board of directors, subject to the rights of the holders of outstanding preferred stock. Dividends paid totaled $829.4 million, $517.6 million and $509.2 million for 2017, 2016 and 2015, respectively. The following table sets forth the quarterly dividends per share paid on our common stock in the periods indicated:

	Years Ended December 31,		
	2017	**2016**	**2015**
First Quarter	**$ 0.615**	$ 0.615	$ 0.605
Second Quarter	**0.615**	0.615	0.605
Third Quarter	**0.745**	0.615	0.605
Fourth Quarter	**0.745**	0.615	0.615
Total	**$ 2.72**	$ 2.46	$ 2.43

Additionally, in February 2018, we paid a quarterly dividend of $0.77 per share ($3.08 per share on an annualized basis), which was paid to shareholders of record as of January 29, 2018.

The Series E Preferred Stock pays quarterly dividends on each share of Series E Preferred Stock, when, as and if declared by our Board of Directors, at a rate of 5.5 percent per year. We paid dividends for the Series E Preferred Stock of $0.6 million in 2017. We paid dividends totaling $0.3 million for the Series E Preferred Stock in February 2018. The $20.0 million issuance of the shares of Series E Preferred Stock and the related accrued dividends of $0.1 million at December 31, 2017, represent noncash financing activities.

Cash Distributions - Prior to the consummation of the Merger Transaction, we received distributions from ONEOK Partners on our common and Class B units and our 2 percent general partner interest, which included our incentive distribution rights. Under the Partnership Agreement, distributions were made to the partners with respect to each calendar quarter in an amount equal to 100 percent of available cash as defined in the Partnership Agreement. Available cash generally was distributed 98 percent to limited partners and 2 percent to the general partner. The general partner's percentage interest in quarterly distributions were increased after certain specified target levels were met during the quarter. Under the incentive distribution provisions, as set forth in the Partnership Agreement, the general partner received:

- 15 percent of amounts distributed in excess of $0.3025 per unit;
- 25 percent of amounts distributed in excess of $0.3575 per unit; and
- 50 percent of amounts distributed in excess of $0.4675 per unit.

Distributions paid to ONEOK Partners unitholders of record at the close of business on January 30, 2017, and May 1, 2017, were $0.79 per unit. Our incentive distribution rights effectively terminated at the close of the Merger Transaction.

The following table sets forth ONEOK Partners' distributions paid during the periods prior to the closing of the Merger Transaction on June 30, 2017:

	Years Ended December 31,		
	2017	**2016**	**2015**
	(*Thousands, except per unit amounts*)		
Distribution per unit	**$ 1.58**	$ 3.16	$ 3.16
General partner distributions	**$ 13,320**	$ 26,640	$ 24,610
Incentive distributions	**201,076**	402,152	371,500
Distributions to general partner	**214,396**	428,792	396,110
Limited partner distributions to ONEOK	**180,646**	361,292	310,230
Limited partner distributions to other unitholders	**270,959**	541,919	524,135
Total distributions paid	**$ 666,001**	$ 1,332,003	$ 1,230,475

Equity Issuances - In January 2018, we completed an underwritten public offering of 21.9 million shares of our common stock at a public offering price of $54.50 per share, generating net proceeds of $1.2 billion. We used the net proceeds from this offering to fund capital expenditures and for general corporate purposes, which included repaying a portion of our outstanding indebtedness.

In July 2017, we established an "at-the-market" equity program for the offer and sale from time to time of our common stock up to an aggregate amount of $1 billion. The program allows us to offer and sell our common stock at prices we deem appropriate through a sales agent. Sales of our common stock may be made by means of ordinary brokers' transactions on the NYSE, in block transactions, or as otherwise agreed to between us and the sales agent. We are under no obligation to offer and sell common stock under the program.

During the year ended December 31, 2017, we sold 8.4 million shares of common stock through our "at-the-market" equity program that resulted in net proceeds of $448.3 million. The net proceeds from these issuances were used for general corporate purposes, including repayment of outstanding indebtedness and to fund capital expenditures.

Prior to the close of the Merger Transaction, ONEOK Partners had an "at-the-market" equity program for the offer and sale from time to time of its common units, up to an aggregate amount of $650 million. During the six months ended June 30, 2017, and the year ended December 31, 2016, no common units were sold through ONEOK Partners' "at-the-market" equity program. Upon the close of the Merger Transaction on June 30, 2017, the ONEOK Partners "at-the-market" equity program terminated.

In August 2015, ONEOK Partners completed a private placement of 21.5 million common units at a price of $30.17 per unit. Additionally, ONEOK Partners completed a concurrent sale of 3.3 million common units at a price of $30.17 per unit to funds managed by Kayne Anderson Capital Advisors in a registered direct offering, which were issued through its existing "at-the-market" equity program. The combined offerings generated net cash proceeds of $749 million to ONEOK Partners. In conjunction with these issuances, ONEOK Partners GP contributed $15.3 million in order to maintain our 2 percent general partner interest in ONEOK Partners. ONEOK Partners used the proceeds for general partnership purposes, including capital expenditures and repayment of commercial paper borrowings.

During the year ended December 31, 2015, ONEOK Partners sold 10.5 million common units through its "at-the-market" equity program, including the units sold to funds managed by Kayne Anderson Capital Advisors in the offering discussed above. The net proceeds, including ONEOK Partners GP's contribution to maintain our 2 percent general partner interest in ONEOK Partners, were $381.6 million, which were used for general partnership purposes, including repayment of commercial paper borrowings.

I. ACCUMULATED OTHER COMPREHENSIVE LOSS

The following table sets forth the balance in accumulated other comprehensive loss for the periods indicated:

	Unrealized Gains (Losses) on Risk-Management Assets/Liabilities (a)	Pension and Postretirement Benefit Plan Obligations (a) (b)	Unrealized Gains (Losses) on Risk-Management Assets/Liabilities of Unconsolidated Affiliates (a)	Accumulated Other Comprehensive Loss (a)
		(*Thousands of dollars*)		
January 1, 2016	$ (42,199)	$ (84,543)	$ (500)	$ (127,242)
Other comprehensive income (loss) before reclassifications	(9,280)	(22,903)	(475)	(32,658)
Amounts reclassified from accumulated other comprehensive loss	(676)	6,210	16	5,550
Other comprehensive income (loss) attributable to ONEOK	(9,956)	(16,693)	(459)	(27,108)
December 31, 2016	(52,155)	(101,236)	(959)	(154,350)
Other comprehensive income (loss) before reclassifications	**(35,013)**	**(12,337)**	**(409)**	**(47,759)**
Amounts reclassified from accumulated other comprehensive loss	**45,541**	**8,162**	**164**	**53,867**
Impact of Merger Transaction (Note B) (c)	**(40,288)**	**—**	**—**	**(40,288)**
Other comprehensive income (loss) attributable to ONEOK	**(29,760)**	**(4,175)**	**(245)**	**(34,180)**
December 31, 2017	**$ (81,915)**	**$ (105,411)**	**$ (1,204)**	**$ (188,530)**

(a) All amounts are presented net of tax.
(b) Includes amounts related to supplemental executive retirement plan.
(c) Includes the remaining portion of ONEOK Partners' accumulated other comprehensive loss at June 30, 2017, that we acquired in the Merger Transaction, related to commodity and interest-rate contracts.

The following table sets forth the effect of reclassifications from accumulated other comprehensive loss in our Consolidated Statements of Income for the periods indicated:

Details about Accumulated Other Comprehensive Loss Components	Years Ended December 31, 2017	2016	2015	Affected Line Item in the Consolidated Statements of Income
	(*Thousands of dollars*)			
Unrealized gains (losses) on risk-management assets/liabilities				
Commodity contracts	**$ (69,561)**	$ 26,422	$ 81,089	Commodity sales revenues
Interest-rate contracts	**(21,025)**	(19,215)	(17,565)	Interest expense
	(90,586)	7,207	63,524	Income before income taxes
	26,899	(230)	(8,815)	Income tax expense
	(63,687)	6,977	54,709	Net income
Noncontrolling interests	**(18,146)**	6,301	39,415	Less: Net income attributable noncontrolling interests
	$ (45,541)	$ 676	$ 15,294	Net income attributable to ONEOK
Pension and postretirement benefit plan obligations (a)				
Amortization of net loss	**$ (15,265)**	$ (12,012)	$ (17,724)	
Amortization of unrecognized prior service cost	**1,662**	1,662	1,568	
	(13,603)	(10,350)	(16,156)	Income before income taxes
	5,441	4,140	6,462	Income tax expense
	$ (8,162)	$ (6,210)	$ (9,694)	Net income attributable to ONEOK
Unrealized gains (losses) on risk-management assets/liabilities of unconsolidated affiliates				
	$ (367)	$ (63)	$ —	Equity in net earnings from investments
	97	10	—	Income tax expense
	(270)	(53)	—	Net income
Noncontrolling interests	**(106)**	(37)	—	Less: Net income attributable to noncontrolling interests
	$ (164)	$ (16)	$ —	Net income attributable to ONEOK
Total reclassifications for the period attributable to ONEOK	**$ (53,867)**	$ (5,550)	$ 5,600	Net income attributable to ONEOK

(a) These components of accumulated other comprehensive loss are included in the computation of net periodic benefit cost. See Note L for additional detail of our net periodic benefit cost.

J. EARNINGS PER SHARE

The following tables set forth the computation of basic and diluted EPS from continuing operations for the periods indicated:

	Year Ended December 31, 2017 Income	Shares	Per Share Amount
	(*Thousands, except per share amounts*)		
Basic EPS from continuing operations			
Income from continuing operations attributable to ONEOK available for common stock	**$ 387,074**	**297,477**	**$ 1.30**
Diluted EPS from continuing operations			
Effect of dilutive securities	**—**	**2,303**	
Income from continuing operations attributable to ONEOK available for common stock and common stock equivalents	**$ 387,074**	**299,780**	**$ 1.29**

	Year Ended December 31, 2016		
	Income	Shares	Per Share Amount
	(*Thousands, except per share amounts*)		
Basic EPS from continuing operations			
Income from continuing operations attributable to ONEOK available for common stock	$ 354,090	211,128	$ 1.68
Diluted EPS from continuing operations			
Effect of dilutive securities	—	1,255	
Income from continuing operations attributable to ONEOK available for common stock and common stock equivalents	$ 354,090	212,383	$ 1.67

	Year Ended December 31, 2015		
	Income	Shares	Per Share Amount
	(*Thousands, except per share amounts*)		
Basic EPS from continuing operations			
Income from continuing operations attributable to ONEOK available for common stock	$ 251,058	210,208	$ 1.19
Diluted EPS from continuing operations			
Effect of dilutive securities	—	333	
Income from continuing operations attributable to ONEOK available for common stock and common stock equivalents	$ 251,058	210,541	$ 1.19

K. SHARE-BASED PAYMENTS

The ONEOK, Inc. Equity Compensation Plan (ECP) and the ONEOK, Inc. Long-Term Incentive Plan (LTIP) provide for the granting of stock-based compensation, including incentive stock options, nonstatutory stock options, stock bonus awards, restricted stock awards, restricted stock unit awards, performance stock awards and performance unit awards to eligible employees and the granting of stock awards to nonemployee directors. We have reserved 10.0 million and 15.6 million shares of common stock for issuance under the ECP and LTIP, respectively. At December 31, 2017, we had 1.9 million shares available for issuance under the ECP and no remaining shares available for issuance under the LTIP. This calculation of available shares reflects shares issued and estimated shares expected to be issued upon vesting of outstanding awards granted under these plans, excluding estimated forfeitures expected to be returned to the plans. These plans allow for the deferral of awards granted in stock or cash, in accordance with Internal Revenue Code section 409A requirements.

Restricted Stock Units - We have granted restricted stock units to key employees that vest at the end of a three-year period and entitle the grantee to receive shares of our common stock. Restricted stock unit awards are measured at fair value as if they were vested and issued on the grant date and adjusted for estimated forfeitures. Restricted stock unit awards granted accrue dividend equivalents in the form of additional restricted stock units prior to vesting. Compensation expense is recognized on a straight-line basis over the vesting period of the award.

Performance Unit Awards - We have granted performance unit awards to key employees. Outstanding performance units vest at the expiration of a three-year period. Upon vesting, a holder of outstanding performance units is entitled to receive a number of shares of our common stock equal to a percentage (0 percent to 200 percent) of the performance units granted, based on our total shareholder return over the vesting period, compared with the total shareholder return of a peer group of other energy companies over the same period. Compensation expense is recognized on a straight-line basis over the period of the award.

If paid, the outstanding performance unit awards entitle the grantee to receive the grant in shares of our common stock. Our outstanding performance unit awards are equity awards with a market-based condition, which results in the compensation cost for these awards being recognized over the requisite service period, provided that the requisite service period is fulfilled, regardless of when, if ever, the market condition is satisfied. The fair value of these performance units was estimated on the grant date based on a Monte Carlo model. Performance stock unit awards granted accrue dividend equivalents in the form of additional performance units prior to vesting. The compensation expense on these awards only will be adjusted for changes in forfeitures.

Stock Compensation Plan for Non-Employee Directors

The ONEOK, Inc. Stock Compensation Plan for Non-Employee Directors (the DSCP) provides for the granting of nonstatutory stock options, stock bonus awards, including performance unit awards and restricted stock awards. Under the DSCP, these awards may be granted by the Executive Compensation Committee at any time, until grants have been made for all shares authorized under the DSCP. We have reserved a total of 1.4 million shares of common stock for issuance under the DSCP, and at December 31, 2017, we had 1.0 million shares available for issuance under the plan. The maximum number of shares of common stock that can be issued to a participant under the DSCP during any year is 40,000. No performance unit awards or restricted stock awards have been made to nonemployee directors under the DSCP. There are no remaining options outstanding under the DSCP.

General

For all awards outstanding, we used a 3 percent forfeiture rate based on historical forfeitures under our share-based payment plans. We currently use treasury stock to satisfy our share-based payment obligations.

Compensation expense for our share-based payment plans described above was $16.6 million, $30.7 million and $11.5 million during 2017, 2016 and 2015, respectively, which is net of tax benefits of $11.1 million, $9.8 million and $4.9 million, respectively.

Restricted Stock Unit Activity

As of December 31, 2017, we had $12.5 million of total unrecognized compensation cost related to our nonvested restricted stock unit awards, which is expected to be recognized over a weighted-average period of 1.9 years. The following tables set forth activity and various statistics for our restricted stock unit awards:

	Number of Units		Weighted Average Price
Nonvested December 31, 2016	**881,647**	**$**	**31.25**
Granted	**281,167**	**$**	**45.11**
Released to participants	**(141,724)**	**$**	**51.21**
Forfeited	**(19,285)**	**$**	**32.07**
Nonvested December 31, 2017	**1,001,805**	**$**	**32.30**

		2017		2016		2015
Weighted-average grant date fair value (per share)	**$**	**45.11**	$	20.04	$	42.98
Fair value of units granted (thousands of dollars)	**$**	**12,685**	$	11,081	$	10,186
Fair value of units vested (thousands of dollars)	**$**	**7,258**	$	4,429	$	6,458

Performance Unit Activity

As of December 31, 2017, we had $17.4 million of total unrecognized compensation cost related to the nonvested performance unit awards, which is expected to be recognized over a weighted-average period of 1.9 years. The following tables set forth activity and various statistics related to the performance unit awards and the assumptions used in the valuations at the respective grant dates:

	Number of Units		Weighted Average Price
Nonvested December 31, 2016	**1,005,751**	**$**	**38.81**
Granted	**311,047**	**$**	**56.65**
Released to participants	**(123,459)**	**$**	**70.50**
Forfeited	**(57,206)**	**$**	**42.29**
Nonvested December 31, 2017	**1,136,133**	**$**	**40.08**

	2017	2016	2015
Volatility (a)	**40.59%**	39.94%	26.70%
Dividend Yield	**4.68%**	11.32%	5.02%
Risk-free Interest Rate	**1.49%**	0.93%	1.00%

(a) - Volatility was based on historical volatility over three years using daily stock price observations.

	2017	2016	2015
Weighted-average grant date fair value (per share)	**$ 56.65**	$ 25.54	$ 50.30
Fair value of units granted (thousands of dollars)	**$ 17,621**	$ 15,229	$ 13,370
Fair value of units vested (thousands of dollars)	**$ 8,704**	$ —	$ 13,736

Employee Stock Purchase Plan

We have reserved a total of 11.6 million shares of common stock for issuance under our ONEOK, Inc. Employee Stock Purchase Plan (the ESPP). Subject to certain exclusions, all full-time employees are eligible to participate in the ESPP. Employees can choose to have up to 10 percent of their annual base pay withheld to purchase our common stock, subject to terms and limitations of the plan. The purchase price of the stock is 85 percent of the lower of its grant date or exercise date market price. Approximately 58 percent, 57 percent and 53 percent of employees participated in the plan in 2017, 2016 and 2015, respectively. Under the plan, we sold 151,803 shares at $44.20 per share in 2017, 232,553 shares at $27.21 per share in 2016 and 222,872 shares at $25.51 per share in 2015.

Employee Stock Award Program

Under our Employee Stock Award Program, we issued, for no monetary consideration, to all eligible employees one share of our common stock when the per-share closing price of our common stock on the NYSE was for the first time at or above $13 per share, and one additional share of common stock when the per-share closing price of our common stock on the NYSE was at or above each one dollar increment above $13. The total number of shares of our common stock available for issuance under this program is 900,000. No shares were issued to employees under this program during 2017, 2016 or 2015.

Deferred Compensation Plan for Non-Employee Directors

The ONEOK, Inc. Nonqualified Deferred Compensation Plan for Non-Employee Directors provides our nonemployee directors the option to defer all or a portion of their compensation for their service on our Board of Directors. Under the plan, directors may elect either a cash deferral option or a phantom stock option. Under the cash deferral option, directors may elect to defer the receipt of all or a portion of their annual retainer fees, which will be credited with interest during the deferral period. Under the phantom stock option, directors may defer all or a portion of their annual retainer fees and receive such fees on a deferred basis in the form of shares of common stock under our Long-Term Incentive Plan or Equity Compensation Plan, which earn the equivalent of dividends declared on our common stock. Shares are distributed to nonemployee directors at the fair market value of our common stock at the date of distribution.

L. EMPLOYEE BENEFIT PLANS

Retirement and Postretirement Benefit Plans

Retirement Plans - We have a defined benefit pension plan covering certain employees and former employees hired before January 1, 2005. Employees hired after December 31, 2004, and employees who accepted a one-time opportunity to opt out of our pension plan are covered by our Profit Sharing Plan. In addition, we have a supplemental executive retirement plan for the benefit of certain officers. No new participants in our supplemental executive retirement plan have been approved since 2005, and effective January 2014, the plan was formally closed to new participants. We fund our pension costs at a level needed to maintain or exceed the minimum funding levels required by the Employee Retirement Income Security Act of 1974, as amended, and the Pension Protection Act of 2006.

Postretirement Benefit Plans - We sponsor health and welfare plans that provide postretirement medical and life insurance benefits to employees hired prior to 2017 who retire with at least five years of service. The postretirement medical plan is contributory with retiree contributions adjusted periodically and contains other cost-sharing features such as deductibles and coinsurance.

Obligations and Funded Status - The following tables set forth our pension and postretirement benefit plans benefit obligations and fair value of plan assets for the periods indicated:

	Pension Benefits		Postretirement Benefits	
	December 31,		December 31,	
	2017	2016	2017	2016
Change in benefit obligation	(*Thousands of dollars*)			
Benefit obligation, beginning of period	**$ 428,386**	$ 390,688	**$ 54,823**	$ 49,496
Service cost	**6,896**	6,501	**662**	596
Interest cost	**18,645**	19,820	**2,261**	2,404
Plan participants' contributions	**—**	—	**901**	894
Actuarial loss	**41,678**	24,458	**3,456**	4,905
Benefits paid	**(13,990)**	(13,081)	**(4,165)**	(3,472)
Benefit obligation, end of period	**481,615**	428,386	**57,938**	54,823
Change in plan assets				
Fair value of plan assets, beginning of period	**261,671**	258,635	**29,550**	28,641
Actual return on plan assets	**50,827**	16,117	**5,385**	1,902
Employer contributions	**7,500**	—	**2,000**	1,000
Plan participants' contributions	**—**	—	**901**	894
Benefits paid	**(13,990)**	(13,081)	**(3,703)**	(2,887)
Fair value of plan assets, end of period	**306,008**	261,671	**34,133**	29,550
Balance at December 31	**$ (175,607)**	$ (166,715)	**$ (23,805)**	$ (25,273)
Current liabilities	**$ (4,544)**	$ (4,363)	**$ —**	$ —
Noncurrent liabilities	**(171,063)**	(162,352)	**(23,805)**	(25,273)
Balance at December 31	**$ (175,607)**	$ (166,715)	**$ (23,805)**	$ (25,273)

The table above includes the supplemental executive retirement plan obligation. ONEOK has investments included in other assets on the Consolidated Balance Sheets, which totaled $93.2 million and $84.5 million at December 31, 2017 and 2016, respectively, for the purpose of funding the obligation. These assets are excluded from the table above as those are not assets of the supplemental executive retirement plan.

The accumulated benefit obligation for our pension plans was $456.6 million and $407.2 million at December 31, 2017 and 2016, respectively.

Components of Net Periodic Benefit Cost - The following table sets forth the components of net periodic benefit cost for our pension and postretirement benefit plans for the periods indicated:

	Pension Benefits			Postretirement Benefits		
	Years Ended December 31,			Years Ended December 31,		
	2017	2016	2015	2017	2016	2015
	(*Thousands of dollars*)					
Components of net periodic benefit cost						
Service cost	**$ 6,896**	$ 6,501	$ 7,565	**$ 662**	$ 596	$ 743
Interest cost	**18,645**	19,820	18,218	**2,261**	2,404	2,347
Expected return on plan assets	**(21,376)**	(20,348)	(20,900)	**(2,257)**	(2,124)	(2,253)
Amortization of prior service cost (credit)	**—**	—	94	**(1,662)**	(1,662)	(1,662)
Amortization of net loss	**13,586**	10,966	15,981	**1,679**	1,046	1,743
Net periodic benefit cost	**$ 17,751**	$ 16,939	$ 20,958	**$ 683**	$ 260	$ 918

Other Comprehensive Income (Loss) - The following table sets forth the amounts recognized in other comprehensive income (loss) related to our pension benefits and postretirement benefits for the periods indicated:

	Pension Benefits			Postretirement Benefits		
	Years Ended December 31,			Years Ended December 31,		
	2017	2016	2015	**2017**	2016	2015
	(*Thousands of dollars*)					
Net gain (loss) arising during the period	**$ (16,572)**	$ (33,043)	$ 5,145	**$ (328)**	$ (5,128)	$ 4,393
Amortization of prior service cost (credit)	**—**	—	94	**(1,662)**	(1,662)	(1,662)
Amortization of net loss	**13,586**	10,966	15,981	**1,679**	1,046	1,743
Deferred income taxes	**(960)**	8,831	(8,488)	**82**	2,297	(1,790)
Total recognized in other comprehensive income (loss)	**$ (3,946)**	$ (13,246)	$ 12,732	**$ (229)**	$ (3,447)	$ 2,684

The table below sets forth the amounts in accumulated other comprehensive loss that had not yet been recognized as components of net periodic benefit expense for the periods indicated:

	Pension Benefits		Postretirement Benefits	
	December 31,		December 31,	
	2017	2016	**2017**	2016
	(*Thousands of dollars*)			
Prior service credit (cost)	**$ —**	$ —	**$ 1,889**	$ 3,550
Accumulated loss	**(160,921)**	(157,935)	**(12,991)**	(14,341)
Accumulated other comprehensive loss	**(160,921)**	(157,935)	**(11,102)**	(10,791)
Deferred income taxes	**62,214**	63,174	**4,398**	4,316
Accumulated other comprehensive loss, net of tax	**$ (98,707)**	$ (94,761)	**$ (6,704)**	$ (6,475)

The following table sets forth the amounts recognized in accumulated comprehensive loss expected to be recognized as components of net periodic benefit expense in the next fiscal year.

	Pension Benefits	Postretirement Benefits
Amounts to be recognized in 2018	(*Thousands of dollars*)	
Prior service (credit) cost	$ —	$ (1,662)
Net loss	$ 17,060	$ 1,338

Actuarial Assumptions - The following table sets forth the weighted-average assumptions used to determine benefit obligations for pension and postretirement benefits for the periods indicated:

	Pension Benefits		Postretirement Benefits	
	December 31,		December 31,	
	2017	2016	**2017**	2016
Discount rate (a)	**3.75%**	4.50%	**3.75%**	4.25%
Compensation increase rate	**3.00%**	3.10%	**N/A**	N/A

(a) The decrease in the discount rate at December 31, 2017, compared with 2016, resulted primarily from narrower credit spreads associated with the bonds in the hypothetical portfolio discussed below.

The following table sets forth the weighted-average assumptions used to determine net periodic benefit costs for the periods indicated:

	Years Ended December 31,		
	2017	2016	2015
Discount rate - pension plans	**4.50%**	5.25%	4.50%
Discount rate - postretirement plans	**4.25%**	5.00%	4.25%
Expected long-term return on plan assets	**7.75%**	7.75%	8.00%
Compensation increase rate	**3.10%**	3.10%	3.15%

We determine our overall expected long-term rate of return on plan assets based on our review of historical returns and economic growth models.

We determine our discount rates annually. We estimate our discount rate based upon a comparison of the expected cash flows associated with our future payments under our pension and postretirement obligations to a hypothetical bond portfolio created using high-quality bonds that closely match expected cash flows. Bond portfolios are developed by selecting a bond for each of the next 60 years based on the maturity dates of the bonds. Bonds selected to be included in the portfolios are only those rated by Moody's as AA- or better and exclude callable bonds, bonds with less than a minimum issue size, yield outliers and other filtering criteria to remove unsuitable bonds.

Health Care Cost Trend Rates - The following table sets forth the assumed health care cost-trend rates for the periods indicated:

	2017	2016
Health care cost-trend rate assumed for next year	**7.00%**	7.25%
Rate to which the cost-trend rate is assumed to decline (the ultimate trend rate)	**5.00%**	5.00%
Year that the rate reaches the ultimate trend rate	**2022**	2022

Assumed health care cost-trend rates have an impact on the amounts reported for our health care plans. As of December 31, 2017, a one percentage point change in assumed health care cost-trend rates would not be material to us.

Plan Assets - Our investment strategy is to invest plan assets in accordance with sound investment practices that emphasize long-term fundamentals. The goal of this strategy is to maximize investment returns while managing risk in order to meet the plan's current and projected financial obligations. The investment policy follows a glide path approach toward liability-driven investing that shifts a higher portfolio weighting to fixed income as the plan's funded status increases. The purpose of liability-driven investing is to structure the asset portfolio to more closely resemble the pension liability and thereby more effectively hedge against changes in the liability. The plan's current investments include a diverse blend of various domestic and international equities, investments in various classes of debt securities, insurance contracts and venture capital. The target allocation for the assets of our pension plan as of December 31, 2017, is as follows:

U.S. large-cap equities	37%
Long duration bonds	30%
Developed foreign large-cap equities	10%
Alternative investments	8%
Mid-cap equities	6%
Emerging markets equities	5%
Small-cap equities	4%
Total	100%

As part of our risk management for the plans, minimums and maximums have been set for each of the asset classes listed above. All investment managers for the plan are subject to certain restrictions on the securities they purchase and, with the exception of indexing purposes, are prohibited from owning our stock.

The following tables set forth our pension benefits and postretirement benefits plan assets by fair value category as of the measurement date:

Asset Category	Pension Benefits December 31, 2017 Level 1	Level 2	Level 3	Subtotal	Measured at NAV (d)	Total
	(Thousands of dollars)					
Investments:						
Equity securities (a)	**$ 176,347**	**$ 19,199**	**$ —**	**$ 195,546**	**$ —**	**$ 195,546**
Government obligations	**—**	**19,481**	**—**	**19,481**	**—**	**19,481**
Corporate obligations (b)	**—**	**62,981**	**—**	**62,981**	**—**	**62,981**
Common/collective trusts	**—**	**6,621**	**—**	**6,621**	**—**	**6,621**
Cash	**298**	**—**	**—**	**298**	**—**	**298**
Other investments (c)	**—**	**—**	**—**	**—**	**21,081**	**21,081**
Fair value of plan assets	**$ 176,645**	**$ 108,282**	**$ —**	**$ 284,927**	**$ 21,081**	**$ 306,008**

(a) - This category represents securities of the respective market sector from diverse industries.
(b) - This category represents bonds from diverse industries.
(c) - This category represents alternative investments in limited partnerships, which can be redeemed with a 30-day notice with no further restrictions. There are no unfunded capital commitments.
(d) - Plan asset investments measured at fair value using the net asset value per share.

Asset Category	Pension Benefits December 31, 2016 Level 1	Level 2	Level 3	Subtotal	Measured at NAV (d)	Total
	(Thousands of dollars)					
Investments:						
Equity securities (a)	$ 146,980	$ 13,606	$ —	$ 160,586	$ —	$ 160,586
Government obligations	—	17,979	—	17,979	—	17,979
Corporate obligations (b)	—	56,484	—	56,484	—	56,484
Common/collective trusts	—	6,577	—	6,577	—	6,577
Cash	43	—	—	43	—	43
Other investments (c)	—	—	—	—	20,002	20,002
Fair value of plan assets	$ 147,023	$ 94,646	$ —	$ 241,669	$ 20,002	$ 261,671

(a) - This category represents securities of the respective market sector from diverse industries.
(b) - This category represents bonds from diverse industries.
(c) - This category represents alternative investments in limited partnerships, which can be redeemed with a 30-day notice with no further restrictions. There are no unfunded capital commitments.
(d) - Plan asset investments measured at fair value using the net asset value per share.

Asset Category	Postretirement Benefits December 31, 2017 Level 1	Level 2	Level 3	Total
	(Thousands of dollars)			
Investments:				
Equity securities (a)	**$ 1,951**	**$ —**	**$ —**	**$ 1,951**
Money market funds	**—**	**1,515**	**—**	**1,515**
Insurance and group annuity contracts	**—**	**30,667**	**—**	**30,667**
Fair value of plan assets	**$ 1,951**	**$ 32,182**	**$ —**	**$ 34,133**

(a) - This category represents securities of the respective market sector from diverse industries.

Asset Category	Postretirement Benefits December 31, 2016 Level 1	Level 2	Level 3	Total
	(*Thousands of dollars*)			
Investments:				
Equity securities (a)	$ 1,777	$ —	$ —	$ 1,777
Money market funds	—	1,259	—	1,259
Insurance and group annuity contracts	—	26,514	—	26,514
Fair value of plan assets	$ 1,777	$ 27,773	$ —	$ 29,550

(a) - This category represents securities of the respective market sector from diverse industries.

Contributions - During 2017, we made $7.5 million in contributions to our defined benefit pension plan and $2.0 million in contributions to our postretirement benefit plans. We contributed $12.3 million to our defined benefit pension plan in January 2018 and expect to make approximately $2.0 million in contributions to our postretirement plans in 2018.

Pension and Postretirement Benefit Payments - Benefit payments for our pension and postretirement benefit plans for the period ending December 31, 2017, were $14.0 million and $4.2 million, respectively. The following table sets forth the pension benefits and postretirement benefits payments expected to be paid in 2018 through 2027:

Benefits to be paid in:	Pension Benefits	Postretirement Benefits
	(*Thousands of dollars*)	
2018	$ 16,796	$ 3,452
2019	$ 18,011	$ 3,653
2020	$ 18,970	$ 3,859
2021	$ 20,206	$ 3,993
2022	$ 21,157	$ 4,023
2023 through 2027	$ 117,048	$ 19,302

The expected benefits to be paid are based on the same assumptions used to measure our benefit obligation at December 31, 2017, and include estimated future employee service.

Other Employee Benefit Plans

401(k) Plan - We have a 401(k) Plan covering all employees, and employee contributions are discretionary. We match 100 percent of employee contributions up to 6 percent of each participant's eligible compensation, subject to certain limits. Our contributions made to the plan were $13.7 million, $11.9 million and $12.0 million in 2017, 2016 and 2015, respectively.

Profit Sharing Plan - We have a profit-sharing plan (Profit Sharing Plan) for all employees hired after December 31, 2004. Employees who were employed prior to January 1, 2005, were given a one-time opportunity to make an irrevocable election to participate in the Profit Sharing Plan and not accrue any additional benefits under our defined benefit pension plan after December 31, 2004. We plan to make a contribution to the Profit Sharing Plan each quarter equal to 1 percent of each participant's eligible compensation during the quarter. Additional discretionary employer contributions may be made at the end of each year. Employee contributions are not allowed under the plan. Our contributions made to the plan were $7.4 million, $8.2 million and $4.9 million in 2017, 2016 and 2015, respectively.

Nonqualified Deferred Compensation Plan - The Nonqualified Deferred Compensation Plan provides select employees, as approved by our Chief Executive Officer, with the option to defer portions of their compensation and provides nonqualified deferred compensation benefits that are not available due to limitations on employer and employee contributions to qualified defined contribution plans under the federal tax laws. The plan also provides benefits in excess of applicable tax limits for certain participants in the defined benefit pension plan who are not participants in the supplemental executive retirement plan. Our contributions to the plan were not material in 2017, 2016 and 2015.

M. INCOME TAXES

The following table sets forth our provision for income taxes for the periods indicated:

	Years Ended December 31,		
	2017	**2016**	**2015**
	(*Thousands of dollars*)		
Current income tax provision			
Federal	**$ 295**	$ 6,086	$ 13,191
State	**1,670**	2,449	2,967
Total current income taxes from continuing operations	**1,965**	8,535	16,158
Deferred income tax provision			
Federal	**376,728**	193,974	116,681
State	**68,589**	9,897	3,761
Total deferred income taxes from continuing operations	**445,317**	203,871	120,442
Total provision for income taxes from continuing operations	**447,282**	212,406	136,600
Discontinued operations	**—**	(1,250)	2,031
Total provision for income taxes	**$ 447,282**	$ 211,156	$ 138,631

The following table is a reconciliation of our income tax provision from continuing operations and excludes discontinued operations for the periods indicated:

	Years Ended December 31,		
	2017	**2016**	**2015**
	(*Thousands of dollars*)		
Income before income taxes	**$ 1,040,801**	$ 957,956	$ 521,876
Less: Net income attributable to noncontrolling interests	**205,678**	391,460	134,218
Net income attributable to ONEOK before income taxes	**835,123**	566,496	387,658
Federal statutory income tax rate	**35.0%**	35.0%	35.0%
Provision for federal income taxes	**292,293**	198,274	135,680
State income taxes, net of federal benefit	**16,197**	12,303	5,800
Deferred tax rate change, inclusive of valuation allowance	**141,283**	43	928
Other, net	**(2,491)**	1,786	(5,808)
Income tax provision	**$ 447,282**	$ 212,406	$ 136,600

The following table sets forth the tax effects of temporary differences that gave rise to significant portions of the deferred tax assets and liabilities for the periods indicated:

	December 31, 2017	December 31, 2016
Deferred tax assets	*(Thousands of dollars)*	
Employee benefits and other accrued liabilities	**$ 85,355**	$ 118,831
Federal net operating loss	**159,162**	26,334
State net operating loss and benefits	**73,277**	39,759
Derivative instruments	**30,060**	32,082
Other	**13,546**	2,425
Total deferred tax assets	**361,400**	219,431
Valuation allowance for state net operating loss and tax credits		
Carryforward expected to expire prior to utilization	**(66,632)**	(9,430)
Net deferred tax assets	**294,768**	210,001
Deferred tax liabilities		
Excess of tax over book depreciation	**64,508**	107,249
Investment in partnerships	**77,035**	1,726,541
Regulatory assets	**15**	33
Total deferred tax liabilities	**141,558**	1,833,823
Net deferred tax assets (liabilities) before discontinued operations	**153,210**	(1,623,822)
Discontinued operations	**—**	10,500
Net deferred tax assets (liabilities)	**$ 153,210**	$ (1,613,322)

In December 2017, the Tax Cuts and Jobs Act was signed into law. The Tax Cuts and Jobs Act makes extensive changes to the U.S. tax laws and includes provisions that, beginning in 2018, reduce the U.S. corporate tax rate to 21 percent from 35 percent, increase expensing for capital-investment, limit the interest deduction, and limit the use of net operating losses to offset future taxable income. Due to the reduction in the corporate tax rate, we revalued our deferred tax assets and liabilities as required at enactment. Our net deferred tax assets represent expected corporate tax benefits in the future. The reduction in the federal corporate tax rate reduces these benefits, which resulted in a one-time noncash charge to net income through income tax expense of $141.3 million, inclusive of the valuation allowance described below, recorded in the fourth quarter 2017. We will continue to monitor U.S. Treasury Department and IRS implementation of the Tax Cuts and Jobs Act and will apply applicable guidance and rulemaking as it becomes available.

Tax benefits related to certain state net operating loss and tax credit carryforwards will begin expiring in 2030 and 2020, respectively. Due to the new tax legislation and the impact of increased expensing for capital-investment, we believe that it is more likely than not that the tax benefits of certain state net operating loss and tax credit carryforwards will not be utilized prior to their expirations; therefore, we recorded a valuation allowance of $54.1 million related to these state tax benefits in the fourth quarter 2017.

The Tax Cuts and Jobs Act may reduce future tariff rates charged on our regulated pipelines. For regulated companies, the effect on deferred tax assets and liabilities of a change in tax rates is recorded as regulatory assets and regulatory liabilities in the period that includes the enactment date, if, as a result of an action by a regulator, it is probable that the effect of the change in tax rates will be recovered from or returned to customers through future rates. The rates charged on substantially all of our regulated natural gas pipelines have been established through shipper specific negotiation, discounts and negotiated settlements, which do not ascribe any specific cost of service elements. The rates charged on substantially all of our regulated NGL pipelines are established through negotiated transportation service agreements that are not adjusted based on a traditional cost of service. We expect future tariff rate changes, if any, related to the change in U.S. corporate tax rate to be established prospectively over time on a similar negotiated basis. If in the future the FERC or other regulatory bodies were to require a refund of previously collected amounts on our regulated pipelines, then we may record a regulatory liability through a one-time charge to expense.

On June 30, 2017, we completed the Merger Transaction in a taxable exchange to the ONEOK Partners unitholders resulting in a book/tax difference in the basis of the underlying assets acquired. We recorded a deferred tax asset of $2.1 billion, computed as the net of the equity value exchanged of $8.8 billion and noncontrolling interests of $3.0 billion at a tax rate of 37 percent. These deferred tax assets were revalued in December 2017, as described above.

As a result of adopting ASU 2016-09 in first quarter 2017, we recorded an adjustment increasing beginning retained earnings and deferred tax assets of $73.4 million to recognize the cumulative tax benefits included in net operating loss carryforwards on the tax return but not reflected in deferred tax assets as of December 31, 2016. Beginning in January 2017, all share-based payment tax effects have been recorded in earnings. In prior periods, tax benefits of employee share-based compensation were not recorded as a deferred tax asset as vesting occurred in periods we were in a net operation loss position, and a portion of the tax benefit did not reduce current taxes payable.

N. UNCONSOLIDATED AFFILIATES

Investments in Unconsolidated Affiliates - The following table sets forth our investments in unconsolidated affiliates for the periods indicated:

	Net Ownership Interest	December 31, 2017	December 31, 2016
		(Thousands of dollars)	
Northern Border Pipeline	50%	**$ 396,800**	$ 328,456
Overland Pass Pipeline Company	50%	**436,111**	444,138
Roadrunner Gas Transmission	50%	**93,048**	94,548
Other	Various	**77,197**	91,665
Investments in unconsolidated affiliates (a)		**$ 1,003,156**	$ 958,807

(a) - Equity-method goodwill (Note A) was $38.8 million and $40.1 million at December 31, 2017 and 2016, respectively.

Equity in Net Earnings from Investments and Impairments - The following table sets forth our equity in net earnings from investments for the periods indicated:

	Years Ended December 31,		
	2017	2016	2015
		(Thousands of dollars)	
Northern Border Pipeline	**$ 68,153**	$ 69,990	$ 66,941
Overland Pass Pipeline Company	**60,067**	53,984	37,783
Roadrunner Gas Transmission	**19,150**	4,445	1,800
Other	**11,908**	11,271	18,776
Equity in net earnings from investments	**$ 159,278**	$ 139,690	$ 125,300
Impairment of equity investments	**$ (4,270)**	$ —	$ (180,583)

Impairment Charges - In the third quarter 2017, following a review of nonstrategic assets for potential divestiture, we recorded $4.3 million of noncash impairment charges related to a nonstrategic equity investment located in Oklahoma, which was later sold.

In 2015, due to the continued and greater than expected decline in volumes gathered in the dry natural gas area of the Powder River Basin and our decision to cease operations of our wholly owned coal-bed methane natural gas gathering system in 2016, we recorded noncash impairment charges of $180.6 million in 2015 related to our Bighorn Gas Gathering, Fort Union Gas Gathering and Lost Creek Gathering Company equity investments.

Unconsolidated Affiliates Financial Information - The following tables set forth summarized combined financial information of our unconsolidated affiliates for the periods indicated:

	December 31, 2017	December 31, 2016
	(*Thousands of dollars*)	
Balance Sheet		
Current assets	**$ 151,907**	$ 143,317
Property, plant and equipment, net	**$ 2,490,692**	$ 2,579,607
Other noncurrent assets	**$ 14,793**	$ 20,784
Current liabilities	**$ 70,434**	$ 77,388
Long-term debt	**$ 479,050**	$ 649,539
Other noncurrent liabilities	**$ 53,830**	$ 69,265
Accumulated other comprehensive loss	**$ (9,946)**	$ (7,450)
Owners' equity	**$ 2,064,024**	$ 1,954,966

	Years Ended December 31, 2017	2016	2015
		(*Thousands of dollars*)	
Income Statement			
Operating revenues	**$ 639,102**	$ 578,542	$ 524,496
Operating expenses (a)	**$ 277,121**	$ 260,753	$ 304,930
Net income (a)	**$ 347,692**	$ 293,921	$ 200,064
Distributions paid to us	**$ 196,114**	$ 196,717	$ 155,918

(a) Includes long-lived asset impairment charges in 2015.

We incurred expenses in transactions with unconsolidated affiliates of $156.1 million, $140.3 million and $104.7 million for 2017, 2016 and 2015, respectively, primarily related to Overland Pass Pipeline Company and Northern Border Pipeline. Accounts payable to our equity-method investees at December 31, 2017 and 2016, was $13.6 million and $11.1 million, respectively.

Northern Border Pipeline - The Northern Border Pipeline partnership agreement provides that distributions to Northern Border Pipeline's partners are to be made on a pro rata basis according to each partner's percentage interest. The Northern Border Pipeline Management Committee determines the amount and timing of such distributions. Any changes to, or suspension of, the cash distribution policy of Northern Border Pipeline requires the unanimous approval of the Northern Border Pipeline Management Committee. Cash distributions are equal to 100 percent of distributable cash flow as determined from Northern Border Pipeline's financial statements based upon EBITDA less interest expense and maintenance capital expenditures. Loans or other advances from Northern Border Pipeline to its partners or affiliates are prohibited under its credit agreement. In 2017, we made an equity contribution of $83 million to Northern Border Pipeline.

Under the terms of settlement with shippers in 2012, Northern Border Pipeline was required to file a rate case by January 1, 2018. In December 2017, Northern Border Pipeline entered into a settlement with shippers that was approved by the FERC in February 2018. The settlement provides for tiered rate reductions beginning January 1, 2018, that will reduce rates 12.5 percent by January 2020 compared with previous rates and requires new rates to be established by January 2024. We do not expect the resulting decrease in equity earnings and cash distributions from Northern Border Pipeline to be material to us.

Overland Pass Pipeline Company - The Overland Pass Pipeline Company limited liability company agreement provides that distributions to Overland Pass Pipeline Company's members are to be made on a pro rata basis according to each member's percentage interest. The Overland Pass Pipeline Company Management Committee determines the amount and timing of such distributions. Any changes to, or suspension of, the cash distributions from Overland Pass Pipeline Company requires the unanimous approval of the Overland Pass Pipeline Management Committee. Cash distributions are equal to 100 percent of available cash as defined in the limited liability company agreement.

Roadrunner Gas Transmission - In March 2015, we entered into a 50-50 joint venture with a subsidiary of Fermaca, a Mexico City-based natural gas infrastructure company, to construct the Roadrunner pipeline to transport natural gas from the

Permian Basin in West Texas to the Mexican border near El Paso, Texas. We contributed $4 million and $65 million to Roadrunner in 2017 and 2016, respectively.

The Roadrunner limited liability company agreement provides that distributions to members are made on a pro rata basis according to each member's ownership interest. As the operator, we have been delegated the authority to determine such distributions in accordance with, and on the frequency set forth in, the Roadrunner limited liability company agreement. Cash distributions are equal to 100 percent of available cash, as defined in the limited liability company agreement.

We have an operating agreement with Roadrunner that provides for reimbursement or payment to us for management services and certain operating costs. Reimbursements and payments from Roadrunner included in operating income in our Consolidated Statements of Income for the years ended December 31, 2017, 2016 and 2015, were not material.

O. COMMITMENTS AND CONTINGENCIES

Commitments - Operating leases represent future minimum lease payments under noncancelable leases covering office space and pipeline equipment. Rental expense in 2017, 2016 and 2015 was not material. We have no material operating leases. Firm transportation and storage contracts are fixed-price contracts that provide us with firm transportation and storage capacity. The following table sets forth our firm transportation and storage contract payments for the periods indicated:

	Firm Transportation and Storage Contracts
	(*Millions of dollars*)
2018	$ 46.1
2019	37.6
2020	37.3
2021	23.0
2022	14.2
Thereafter	20.8
Total	$ 179.0

Environmental Matters and Pipeline Safety - The operation of pipelines, plants and other facilities for the gathering, processing, transportation and storage of natural gas, NGLs, condensate and other products is subject to numerous and complex laws and regulations pertaining to health, safety and the environment. As an owner and/or operator of these facilities, we must comply with United States laws and regulations at the federal, state, local and tribal levels that relate to air and water quality, hazardous and solid waste management and disposal, cultural resource protection and other environmental matters. The cost of planning, designing, constructing and operating pipelines, plants and other facilities must incorporate compliance with these laws and regulations and safety standards. Failure to comply with these laws and regulations may trigger a variety of administrative, civil and potentially criminal enforcement measures, including citizen suits, which can include the assessment of monetary penalties, the imposition of remedial requirements and the issuance of injunctions or restrictions on operation or construction. Management believes that, based on currently known information, compliance with these laws and regulations will not have a material adverse effect on our results of operations, financial condition or cash flows.

Legal Proceedings - Gas Index Pricing Litigation - As previously reported, we and our affiliate, ONEOK Energy Services Company, L.P. (OESC), along with several other energy companies, were named as defendants in multiple lawsuits arising from alleged market manipulation or false reporting of natural gas prices to natural gas-index publications alleged to have occurred prior to 2003.

In March 2017, the United States District Court for the District of Nevada (the Court) granted summary judgment to OESC in *Sinclair Oil Corporation v. ONEOK Energy Services Company, L.P.* (filed in the United States District Court for the District of Wyoming in September 2005, transferred to MDL-1566 in the Court). In September 2017, the Court entered a final judgment in favor of OESC in *Sinclair*, which was appealed by Sinclair Oil Corporation to the Ninth Circuit Court of Appeals. We expect that future charges, if any, from the ultimate resolution of the *Sinclair* case will not be material to our results of operations, financial position or cash flows.

In May 2017, the Court approved the following previously announced settlements:

- *Learjet, Inc., et al. v. ONEOK, Inc., et al.* (filed in the District Court of Wyandotte, Kansas, in November 2005, transferred to MDL-1566 in the Court);
- *Arandell Corporation, et al. v. Xcel Energy, Inc., et al.* (filed in the Circuit Court for Dane County, Wisconsin, in December 2006, transferred to MDL-1566 in the Court);
- *Heartland Regional Medical Center, et al. v. ONEOK, Inc., et al.* (filed in the Circuit Court of Buchanan County, Missouri, in March 2007, transferred to MDL-1566 in the Court); and
- *NewPage Wisconsin System v. CMS Energy Resource Management Company, et al.* (filed in the Circuit Court for Wood County, Wisconsin, in March 2009, transferred to MDL-1566 in the Court and consolidated with the *Arandell* case).

The Court later entered a final judgment dismissing these actions with prejudice as to us and our affiliates, which became final and nonappealable in July 2017. The amount paid to settle these cases was not material to our results of operations, financial position or cash flows and was paid with cash on hand.

Other Legal Proceedings - We are a party to various other litigation matters and claims that have arisen in the normal course of our operations. While the results of these litigation matters and claims cannot be predicted with certainty, we believe the reasonably possible losses from such matters, individually and in the aggregate, are not material. Additionally, we believe the probable final outcome of such matters will not have a material adverse effect on our consolidated results of operations, financial position or cash flows.

P. SEGMENTS

Segment Descriptions - Our operations are divided into three reportable business segments, as follows:

- our Natural Gas Gathering and Processing segment gathers, treats and processes natural gas;
- our Natural Gas Liquids segment gathers, treats, fractionates and transports NGLs and stores, markets and distributes NGL products; and
- our Natural Gas Pipelines segment operates regulated interstate and intrastate natural gas transmission pipelines and natural gas storage facilities.

Other and eliminations consist of the corporate and Merger Transaction-related costs, the operating and leasing activities of our headquarters building and related parking facility and eliminations necessary to reconcile our reportable segments to our Consolidated Financial Statements.

Accounting Policies - The accounting policies of the segments are described in Note A. Our chief operating decision-maker reviews the financial performance of each of our three segments, as well as our financial performance as a whole, on a regular basis. Beginning in 2016, adjusted EBITDA by segment is utilized in this evaluation. We believe this financial measure is useful to investors because it and similar measures are used by many companies in our industry as a measurement of financial performance and are commonly employed by financial analysts and others to evaluate our financial performance and to compare financial performance among companies in our industry. Adjusted EBITDA for each segment is defined as net income adjusted for interest expense, depreciation and amortization, noncash impairment charges, income taxes, allowance for equity funds used during construction, noncash compensation, and other noncash items. Prior periods have been adjusted to conform to current presentation. This calculation may not be comparable with similarly titled measures of other companies.

Customers - Our Natural Gas Gathering and Processing segment derives services revenue primarily from crude oil and natural gas producers, which include both large integrated and independent exploration and production companies. The downstream commodity sales customers of our Natural Gas Gathering and Processing segment are primarily utilities, large industrial companies, marketing companies and our NGL affiliate. Our Natural Gas Liquids segment's customers are primarily NGL and natural gas gathering and processing companies; large integrated and independent crude oil and natural gas production companies; propane distributors; ethanol producers; and petrochemical, refining and NGL marketing companies. Our Natural Gas Pipelines segment's customers are primarily local natural gas distribution companies, electric-generation companies, large industrial companies, municipalities, producers and marketing companies.

For each of the years ended December 31, 2017, 2016 and 2015, we had no single customer from which we received 10 percent or more of our consolidated revenues.

Operating Segment Information - The following tables set forth certain selected financial information for our operating segments for the periods indicated:

Year Ended December 31, 2017	Natural Gas Gathering and Processing	Natural Gas Liquids (a)	Natural Gas Pipelines (b)	Total Segments
	(Thousands of dollars)			
Sales to unaffiliated customers	$ 1,750,655	$ 10,009,576	$ 411,490	$ 12,171,721
Intersegment revenues	1,275,919	616,628	8,442	1,900,989
Total revenues	3,026,574	10,626,204	419,932	14,072,710
Cost of sales and fuel (exclusive of depreciation and items shown separately below)	(2,216,355)	(9,176,494)	(43,424)	(11,436,273)
Operating costs	(309,536)	(359,753)	(126,241)	(795,530)
Equity in net earnings from investments	12,098	59,876	87,304	159,278
Other	5,691	5,106	2,247	13,044
Segment adjusted EBITDA	$ 518,472	$ 1,154,939	$ 339,818	$ 2,013,229
Depreciation and amortization	$ (184,923)	$ (167,277)	$ (51,025)	$ (403,225)
Impairment of long-lived assets and equity investments	$ (20,240)	$ —	$ —	$ (20,240)
Total assets	$ 5,495,163	$ 8,782,700	$ 2,055,020	$ 16,332,883
Capital expenditures	$ 284,205	$ 114,267	$ 95,564	$ 494,036

(a) - Our Natural Gas Liquids segment has regulated and nonregulated operations. Our Natural Gas Liquids segment's regulated operations had revenues of $1.2 billion, of which $1.0 billion related to sales within the segment and cost of sales and fuel of $497.4 million.
(b) - Our Natural Gas Pipelines segment has regulated and nonregulated operations. Our Natural Gas Pipelines segment's regulated operations had revenues of $264.9 million and cost of sales and fuel of $44.0 million.

Year Ended December 31, 2017	Total Segments	Other and Eliminations	Total
	(Thousands of dollars)		
Reconciliations of total segments to consolidated			
Sales to unaffiliated customers	$ 12,171,721	$ 2,186	$ 12,173,907
Intersegment revenues	1,900,989	(1,900,989)	—
Total revenues	$ 14,072,710	$ (1,898,803)	$ 12,173,907
Cost of sales and fuel (exclusive of depreciation and operating costs)	$ (11,436,273)	$ 1,898,228	$ (9,538,045)
Operating costs	$ (795,530)	$ (38,056)	$ (833,586)
Depreciation and amortization	$ (403,225)	$ (3,110)	$ (406,335)
Impairment of long-lived assets and equity investments	$ (20,240)	$ —	$ (20,240)
Equity in net earnings from investments	$ 159,278	$ —	$ 159,278
Total assets	$ 16,332,883	$ 513,054	$ 16,845,937
Capital expenditures	$ 494,036	$ 18,357	$ 512,393

Year Ended December 31, 2016	Natural Gas Gathering and Processing	Natural Gas Liquids (a)	Natural Gas Pipelines (b)	Total Segments
	(Thousands of dollars)			
Sales to unaffiliated customers	$ 1,375,738	$ 7,168,983	$ 373,738	$ 8,918,459
Intersegment revenues	675,839	506,671	5,623	1,188,133
Total revenues	2,051,577	7,675,654	379,361	10,106,592
Cost of sales and fuel (exclusive of depreciation and items shown separately below)	(1,331,542)	(6,321,377)	(30,561)	(7,683,480)
Operating costs	(285,599)	(327,597)	(115,628)	(728,824)
Equity in net earnings from investments	10,742	54,513	74,435	139,690
Other	1,600	(1,574)	5,530	5,556
Segment adjusted EBITDA	$ 446,778	$ 1,079,619	$ 313,137	$ 1,839,534
Depreciation and amortization	$ (178,548)	$ (163,303)	$ (46,718)	$ (388,569)
Total assets	$ 5,320,666	$ 8,347,961	$ 1,946,318	$ 15,614,945
Capital expenditures	$ 410,485	$ 105,861	$ 96,274	$ 612,620

(a) - Our Natural Gas Liquids segment has regulated and nonregulated operations. Our Natural Gas Liquids segment's regulated operations had revenues of $1.2 billion, of which $992.8 million related to sales within the segment and cost of sales and fuel of $458.7 million.
(b) - Our Natural Gas Pipelines segment has regulated and nonregulated operations. Our Natural Gas Pipelines segment's regulated operations had revenues of $238.7 million and cost of sales and fuel of $30.0 million.

Year Ended December 31, 2016	Total Segments	Other and Eliminations	Total
	(Thousands of dollars)		
Reconciliations of total segments to consolidated			
Sales to unaffiliated customers	$ 8,918,459	$ 2,475	$ 8,920,934
Intersegment revenues	1,188,133	(1,188,133)	—
Total revenues	$ 10,106,592	$ (1,185,658)	$ 8,920,934
Cost of sales and fuel (exclusive of depreciation and operating costs)	$ (7,683,480)	$ 1,187,356	$ (6,496,124)
Operating costs	$ (728,824)	$ (28,360)	$ (757,184)
Depreciation and amortization	$ (388,569)	$ (3,016)	$ (391,585)
Equity in net earnings from investments	$ 139,690	$ —	$ 139,690
Total assets	$ 15,614,945	$ 523,806	$ 16,138,751
Capital expenditures	$ 612,620	$ 12,014	$ 624,634

Year Ended December 31, 2015		Natural Gas Gathering and Processing		Natural Gas Liquids (a)		Natural Gas Pipelines (b)		Total Segments
				(Thousands of dollars)				
Sales to unaffiliated customers	$	1,187,390	$	6,248,002	$	325,676	$	7,761,068
Intersegment revenues		649,726		331,697		6,771		988,194
Total revenues		1,837,116		6,579,699		332,447		8,749,262
Cost of sales and fuel (exclusive of depreciation and items shown separately below)		(1,265,617)		(5,328,256)		(34,481)		(6,628,354)
Operating costs		(272,418)		(314,505)		(105,720)		(692,643)
Equity in net earnings from investments		17,863		38,696		68,741		125,300
Other		1,610		(3,342)		13,993		12,261
Segment adjusted EBITDA	$	318,554	$	972,292	$	274,980	$	1,565,826
Depreciation and amortization	$	(150,008)	$	(158,709)	$	(43,479)	$	(352,196)
Impairment of long-lived assets	$	(73,681)	$	(9,992)	$	—	$	(83,673)
Impairment of equity investments	$	(180,583)	$	—	$	—	$	(180,583)
Total assets	$	5,123,450	$	8,017,799	$	1,851,857	$	14,993,106
Capital expenditures	$	887,938	$	226,135	$	58,215	$	1,172,288

(a) - Our Natural Gas Liquids segment has regulated and nonregulated operations. Our Natural Gas Liquids segment's regulated operations had revenues of $954.8 million, of which $770.1 million related to sales within the segment and cost of sales and fuel of $412.6 million.
(b) - Our Natural Gas Pipelines segment has regulated and nonregulated operations. Our Natural Gas Pipelines segment's regulated operations had revenues of $266.9 million and cost of sales and fuel of $31.1 million.

Year Ended December 31, 2015		Total Segments		Other and Eliminations		Total
				(Thousands of dollars)		
Reconciliations of total segments to consolidated						
Sales to unaffiliated customers	$	7,761,068	$	2,138	$	7,763,206
Intersegment revenues		988,194		(988,194)		—
Total revenues	$	8,749,262	$	(986,056)	$	7,763,206
Cost of sales and fuel (exclusive of depreciation and operating costs)	$	(6,628,354)	$	987,302	$	(5,641,052)
Operating costs	$	(692,643)	$	(688)	$	(693,331)
Depreciation and amortization	$	(352,196)	$	(2,424)	$	(354,620)
Impairment of long-lived assets	$	(83,673)	$	—	$	(83,673)
Impairment of equity investments	$	(180,583)	$	—	$	(180,583)
Equity in net earnings from investments	$	125,300	$	—	$	125,300
Total assets	$	14,993,106	$	453,005	$	15,446,111
Capital expenditures	$	1,172,288	$	16,024	$	1,188,312

(*Unaudited*)	Years Ended December 31, 2017	2016	2015
Reconciliation of income from continuing operations to total segment adjusted EBITDA	(*Thousands of dollars*)		
Income from continuing operations	**$ 593,519**	$ 745,550	$ 385,276
Add:			
Interest expense, net of capitalized interest	**485,658**	469,651	416,787
Depreciation and amortization	**406,335**	391,585	354,620
Income taxes	**447,282**	212,406	136,600
Impairment charges	**20,240**	—	264,256
Noncash compensation expense	**13,421**	31,981	13,799
Other corporate costs and noncash items (a)	**46,774**	(11,639)	(5,512)
Total segment adjusted EBITDA	**$ 2,013,229**	$ 1,839,534	$ 1,565,826

(a) - The year ended December 31, 2017, includes our April 2017 $20.0 million contribution of Series E Preferred Stock to the Foundation and costs related to the Merger Transaction of $30.0 million.

Q. QUARTERLY FINANCIAL DATA (UNAUDITED)

Year Ended December 31, 2017	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(*Thousands of dollars, except per share amounts*)			
Total revenues	**$ 2,749,611**	**$ 2,725,772**	**$ 2,906,366**	**$ 3,792,158**
Net income	**$ 186,185**	**$ 175,991**	**$ 166,531**	**$ 64,812**
Net income attributable to ONEOK	**$ 87,361**	**$ 71,693**	**$ 165,742**	**$ 63,045**
Net income attributable to common shareholders	**$ 87,361**	**$ 71,476**	**$ 165,466**	**$ 62,771**
Earnings per share total				
Basic	**$ 0.41**	**$ 0.34**	**$ 0.43**	**$ 0.16**
Diluted	**$ 0.41**	**$ 0.33**	**$ 0.43**	**$ 0.16**

The fourth quarter 2017 includes a one-time noncash charge of $141.3 million related to revaluation of our deferred tax balances and a valuation allowance on certain state net operating loss and tax credit carryforwards resulting from the enactment of the Tax Cuts and Jobs Act, as described in Note M.

The third quarter 2017 includes noncash impairment charges of $20.2 million related to Natural Gas Gathering and Processing assets and equity investments.

The second quarter 2017 includes a $20.0 million noncash expense related to our Series E Preferred Stock contribution to the Foundation and operating costs related to the Merger Transaction of $30.0 million.

Year Ended December 31, 2016	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(*Thousands of dollars except per share amounts*)			
Total revenues	$ 1,774,459	$ 2,134,107	$ 2,357,907	$ 2,654,461
Income from continuing operations	$ 175,911	$ 180,086	$ 194,792	$ 194,761
Income (loss) from discontinued operations, net of tax	$ (952)	$ (227)	$ (576)	$ (296)
Net income	$ 174,959	$ 179,859	$ 194,216	$ 194,465
Net income attributable to ONEOK	$ 83,446	$ 85,944	$ 92,144	$ 90,505
Earnings per share total				
Basic	$ 0.40	$ 0.41	$ 0.44	$ 0.43
Diluted	$ 0.40	$ 0.40	$ 0.43	$ 0.43

R. SUPPLEMENTAL CONDENSED CONSOLIDATING FINANCIAL INFORMATION

ONEOK and ONEOK Partners are issuers of certain public debt securities. Effective with the Merger Transaction, we, ONEOK Partners and the Intermediate Partnership issued, to the extent not already in place, guarantees of the indebtedness of ONEOK and ONEOK Partners. The Intermediate Partnership holds all of the equity in ONEOK Partners' subsidiaries, as well as a 50 percent interest in Northern Border Pipeline. In lieu of providing separate financial statements for each subsidiary issuer and guarantor, we have included the accompanying condensed consolidating financial statements based on Rule 3-10 of the SEC's Regulation S-X. We have presented each of the parent and subsidiary issuers in separate columns in this single set of condensed consolidating financial statements.

For purposes of the following footnote:

- we are referred to as "Parent Issuer and Guarantor";
- ONEOK Partners is referred to as "Subsidiary Issuer and Guarantor";
- the Intermediate Partnership is referred to as "Guarantor Subsidiary"; and
- the "Non-Guarantor Subsidiaries" are all subsidiaries other than the Guarantor Subsidiary and Subsidiary Issuer and Guarantor.

The following supplemental condensed consolidating financial information is presented on an equity-method basis reflecting the separate accounts of ONEOK, ONEOK Partners and the Intermediate Partnership, the combined accounts of the Non-Guarantor Subsidiaries, the combined consolidating adjustments and eliminations, and our consolidated amounts for the periods indicated.

Condensed Consolidating Statements of Income

	Year Ended December 31, 2017					
	Parent Issuer & Guarantor	Subsidiary Issuer & Guarantor	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidating Entries	Total
	(*Millions of dollars*)					
Revenues						
Commodity sales	$ —	$ —	$ —	$ 9,862.7	$ —	$ 9,862.7
Services	—	—	—	2,313.2	(2.0)	2,311.2
Total revenues	—	—	—	12,175.9	(2.0)	12,173.9
Cost of sales and fuel (exclusive of items shown separately below)	—	—	—	9,538.0	—	9,538.0
Operating expenses	28.7	—	9.2	1,204.0	(2.0)	1,239.9
Impairment of long-lived assets	—	—	—	16.0	—	16.0
Gain on sale of assets	—	—	—	(0.9)	—	(0.9)
Operating income	(28.7)	—	(9.2)	1,418.8	—	1,380.9
Equity in net earnings from investments	1,236.6	1,215.7	1,224.9	100.7	(3,618.6)	159.3
Impairment of equity investments	—	—	—	(4.3)	—	(4.3)
Other income (expense), net	(1.4)	353.1	353.1	(8.0)	(706.2)	(9.4)
Interest expense, net	(137.1)	(353.1)	(353.1)	(348.6)	706.2	(485.7)
Income before income taxes	1,069.4	1,215.7	1,215.7	1,158.6	(3,618.6)	1,040.8
Income taxes	(480.2)	—	—	32.9	—	(447.3)
Net income	589.2	1,215.7	1,215.7	1,191.5	(3,618.6)	593.5
Less: Net income attributable to noncontrolling interests	201.4	—	—	4.3	—	205.7
Net income attributable to ONEOK	387.8	1,215.7	1,215.7	1,187.2	(3,618.6)	387.8
Less: Preferred stock dividends	0.8	—	—	—	—	0.8
Net income available to common shareholders	$ 387.0	$ 1,215.7	$ 1,215.7	$ 1,187.2	$ (3,618.6)	$ 387.0

	Year Ending December 31, 2016					
	Parent Issuer & Guarantor	**Subsidiary Issuer & Guarantor**	**Guarantor Subsidiary**	**Combined Non-Guarantor Subsidiaries**	**Consolidating Entries**	**Total**
	(Millions of dollars)					
Revenues						
Commodity sales	$ —	$ —	$ —	$ 6,858.5	$ —	$ 6,858.5
Services	—	—	—	2,064.3	(1.8)	2,062.5
Total revenues	—	—	—	8,922.8	(1.8)	8,921.0
Cost of sales and fuel (exclusive of items shown separately below)	—	—	—	6,496.1	—	6,496.1
Operating expenses	28.8	—	—	1,121.8	(1.8)	1,148.8
(Gain) loss on sale of assets	0.3	—	—	(9.9)	—	(9.6)
Operating income	(29.1)	—	—	1,314.8	—	1,285.7
Equity in net earnings from investments	1,063.9	1,066.8	1,066.8	69.7	(3,127.5)	139.7
Other income (expense), net	5.1	373.5	373.5	(2.8)	(747.0)	2.3
Interest expense, net	(102.9)	(373.5)	(373.5)	(366.8)	747.0	(469.7)
Income before income taxes	937.0	1,066.8	1,066.8	1,014.9	(3,127.5)	958.0
Income taxes	(199.0)	—	—	(13.4)	—	(212.4)
Income from continuing operations	738.0	1,066.8	1,066.8	1,001.5	(3,127.5)	745.6
Income (loss) from discontinued operations, net of tax	—	—	—	(2.1)	—	(2.1)
Net income	738.0	1,066.8	1,066.8	999.4	(3,127.5)	743.5
Less: Net income attributable to noncontrolling interests	386.0	—	—	5.5	—	391.5
Net income attributable to ONEOK	$ 352.0	$ 1,066.8	$ 1,066.8	$ 993.9	$ (3,127.5)	$ 352.0

	Year Ending December 31, 2015					
	Parent Issuer & Guarantor	**Subsidiary Issuer & Guarantor**	**Guarantor Subsidiary**	**Combined Non-Guarantor Subsidiaries**	**Consolidating Entries**	**Total**
	(Millions of dollars)					
Revenues						
Commodity sales	$ —	$ —	$ —	$ 6,098.3	$ —	$ 6,098.3
Services	—	—	—	1,669.8	(4.9)	1,664.9
Total revenues	—	—	—	7,768.1	(4.9)	7,763.2
Cost of sales and fuel (exclusive of items shown separately below)	—	—	—	5,641.1	—	5,641.1
Operating expenses	1.2	—	—	1,051.5	(4.9)	1,047.8
Impairment of long-lived assets	—	—	—	83.7	—	83.7
Gain on sale of assets	—	—	—	(5.6)	—	(5.6)
Operating income	(1.2)	—	—	997.4	—	996.2
Equity in net earnings from investments	583.8	589.5	589.5	58.4	(1,695.9)	125.3
Impairment of equity investments	—	—	—	(180.6)	—	(180.6)
Other income (expense), net	4.0	371.0	371.0	(6.2)	(742.0)	(2.2)
Interest expense, net	(85.1)	(371.0)	(371.0)	(331.7)	742.0	(416.8)
Income before income taxes	501.5	589.5	589.5	537.3	(1,695.9)	521.9
Income taxes	(130.7)	—	—	(5.9)	—	(136.6)
Income from continuing operations	370.8	589.5	589.5	531.4	(1,695.9)	385.3
Income (loss) from discontinued operations, net of tax	—	—	—	(6.1)	—	(6.1)
Net income	370.8	589.5	589.5	525.3	(1,695.9)	379.2
Less: Net income attributable to noncontrolling interests	125.8	—	—	8.4	—	134.2
Net income attributable to ONEOK	$ 245.0	$ 589.5	$ 589.5	$ 516.9	$ (1,695.9)	$ 245.0

Condensed Consolidating Statements of Comprehensive Income

	Year Ended December 31, 2017					
	Parent Issuer & Guarantor	Subsidiary Issuer & Guarantor	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidating Entries	Total
	(*Millions of dollars*)					
Net income	**$ 589.2**	**$ 1,215.7**	**$ 1,215.7**	**$ 1,191.5**	**$ (3,618.6)**	**$ 593.5**
Other comprehensive income (loss), net of tax						
Unrealized gains (losses) on derivatives, net of tax	**19.1**	**(72.2)**	**(40.6)**	**(8.8)**	**81.1**	**(21.4)**
Realized (gains) losses on derivatives in net income, net of tax	**2.5**	**86.5**	**69.6**	**44.3**	**(139.2)**	**63.7**
Change in pension and postretirement benefit plan liability, net of tax	**(4.2)**	**—**	**—**	**—**	**—**	**(4.2)**
Other comprehensive income (loss) on investments in unconsolidated affiliates, net of tax	**—**	**(1.1)**	**(1.1)**	**(1.0)**	**2.2**	**(1.0)**
Total other comprehensive income (loss), net of tax	**17.4**	**13.2**	**27.9**	**34.5**	**(55.9)**	**37.1**
Comprehensive income	**606.6**	**1,228.9**	**1,243.6**	**1,226.0**	**(3,674.5)**	**630.6**
Less: Comprehensive income attributable to noncontrolling interests	**232.4**	**—**	**—**	**4.3**	**—**	**236.7**
Comprehensive income attributable to ONEOK	**$ 374.2**	**$ 1,228.9**	**$ 1,243.6**	**$ 1,221.7**	**$ (3,674.5)**	**$ 393.9**

	Year Ending December 31, 2016					
	Parent Issuer & Guarantor	Subsidiary Issuer & Guarantor	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidating Entries	Total
	(*Millions of dollars*)					
Net income	$ 738.0	$ 1,066.8	$ 1,066.8	$ 999.4	$ (3,127.5)	$ 743.5
Other comprehensive income (loss), net of tax						
Unrealized gains (losses) on derivatives, net of tax	—	(35.8)	(78.5)	(108.8)	192.8	(30.3)
Realized (gains) losses on derivatives in net income, net of tax	2.1	(10.7)	(26.4)	(33.4)	61.4	(7.0)
Change in pension and postretirement benefit plan liability, net of tax	(16.7)	—	—	—	—	(16.7)
Other comprehensive income (loss) on investments in unconsolidated affiliates, net of tax	—	(1.8)	(1.8)	(3.3)	5.4	(1.5)
Total other comprehensive income (loss), net of tax	(14.6)	(48.3)	(106.7)	(145.5)	259.6	(55.5)
Comprehensive income	723.4	1,018.5	960.1	853.9	(2,867.9)	688.0
Less: Comprehensive income attributable to noncontrolling interests	357.6	—	—	5.5	—	363.1
Comprehensive income attributable to ONEOK	$ 365.8	$ 1,018.5	$ 960.1	$ 848.4	$ (2,867.9)	$ 324.9

	Year Ending December 31, 2015					
	Parent Issuer & Guarantor	**Subsidiary Issuer & Guarantor**	**Guarantor Subsidiary**	**Combined Non-Guarantor Subsidiaries**	**Consolidating Entries**	**Total**
	(*Millions of dollars*)					
Net income	$ 370.8	$ 589.5	$ 589.5	$ 525.3	$ (1,695.9)	$ 379.2
Other comprehensive income (loss), net of tax						
Unrealized gains (losses) on derivatives, net of tax	—	47.5	70.1	111.5	(187.7)	41.4
Realized (gains) losses on derivatives in net income, net of tax	2.1	(67.0)	(81.1)	(137.9)	229.2	(54.7)
Unrealized holding gains (losses) on available-for-sale securities, net of tax	—	—	—	(1.0)	—	(1.0)
Change in pension and postretirement benefit plan liability, net of tax	15.4	—	—	—	—	15.4
Other comprehensive income (loss) on investments in unconsolidated affiliates, net of tax	—	(1.9)	(1.9)	(3.5)	5.7	(1.6)
Total other comprehensive income (loss), net of tax	17.5	(21.4)	(12.9)	(30.9)	47.2	(0.5)
Comprehensive income	388.3	568.1	576.6	494.4	(1,648.7)	378.7
Less: Comprehensive income attributable to noncontrolling interests	116.2	—	—	8.4	—	124.6
Comprehensive income attributable to ONEOK	$ 272.1	$ 568.1	$ 576.6	$ 486.0	$ (1,648.7)	$ 254.1

Condensed Consolidating Balance Sheets

	December 31, 2017					
	Parent Issuer & Guarantor	Subsidiary Issuer & Guarantor	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidating Entries	Total
Assets	(*Millions of dollars*)					
Current assets						
Cash and cash equivalents	$ 37.2	$ —	$ —	$ —	$ —	$ 37.2
Accounts receivable, net	—	—	—	1,203.0	—	1,203.0
Materials and supplies	—	—	—	90.3	—	90.3
Natural gas and natural gas liquids in storage	—	—	—	342.3	—	342.3
Other current assets	9.8	1.3	—	80.6	—	91.7
Total current assets	47.0	1.3	—	1,716.2	—	1,764.5
Property, plant and equipment						
Property, plant and equipment	128.3	—	—	15,431.3	—	15,559.6
Accumulated depreciation and amortization	86.4	—	—	2,775.1	—	2,861.5
Net property, plant and equipment	41.9	—	—	12,656.2	—	12,698.1
Investments and other assets						
Investments	5,752.1	3,133.7	8,058.4	803.0	(16,744.0)	1,003.2
Intercompany notes receivable	2,926.9	8,627.8	3,703.1	—	(15,257.8)	—
Other assets	416.9	0.2	—	1,007.4	(44.4)	1,380.1
Total investments and other assets	9,095.9	11,761.7	11,761.5	1,810.4	(32,046.2)	2,383.3
Total assets	$ 9,184.8	$ 11,763.0	$ 11,761.5	$ 16,182.8	$ (32,046.2)	$ 16,845.9
Liabilities and equity						
Current liabilities						
Current maturities of long-term debt	$ —	$ 425.0	$ —	$ 7.7	$ —	$ 432.7
Short-term borrowings	614.7	—	—	—	—	614.7
Accounts payable	12.0	—	—	1,128.6	—	1,140.6
Other current liabilities	65.9	85.0	—	328.4	—	479.3
Total current liabilities	692.6	510.0	—	1,464.7	—	2,667.3
Intercompany debt	—	—	8,627.8	6,630.0	(15,257.8)	—
Long-term debt, excluding current maturities	2,726.4	5,336.4	—	28.8	—	8,091.6
Deferred credits and other liabilities	237.9	—	—	208.1	(44.4)	401.6
Commitments and contingencies						
Equity						
Equity excluding noncontrolling interests in consolidated subsidiaries	5,527.9	5,916.6	3,133.7	7,693.7	(16,744.0)	5,527.9
Noncontrolling interests in consolidated subsidiaries	—	—	—	157.5	—	157.5
Total equity	5,527.9	5,916.6	3,133.7	7,851.2	(16,744.0)	5,685.4
Total liabilities and equity	$ 9,184.8	$ 11,763.0	$ 11,761.5	$ 16,182.8	$ (32,046.2)	$ 16,845.9

	December 31, 2016					
	Parent Issuer & Guarantor	Subsidiary Issuer & Guarantor	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidating Entries	Total
Assets	*(Millions of dollars)*					
Current assets						
Cash and cash equivalents	$ 248.5	$ —	$ 0.4	$ —	$ —	$ 248.9
Accounts receivable, net	—	—	—	872.4	—	872.4
Materials and supplies	—	—	—	60.9	—	60.9
Natural gas and natural gas liquids in storage	—	—	—	140.0	—	140.0
Other current assets	7.2	—	—	99.7	—	106.9
Assets of discontinued operations	—	—	—	0.6	—	0.6
Total current assets	255.7	—	0.4	1,173.6	—	1,429.7
Property, plant and equipment						
Property, plant and equipment	139.8	—	—	14,938.7	—	15,078.5
Accumulated depreciation and amortization	90.4	—	—	2,416.7	—	2,507.1
Net property, plant and equipment	49.4	—	—	12,522.0	—	12,571.4
Investments and other assets						
Investments	2,931.9	3,222.1	6,805.4	631.1	(12,631.7)	958.8
Intercompany notes receivable	205.2	10,615.0	7,031.3	—	(17,851.5)	—
Goodwill and intangible assets	—	—	—	1,005.4	—	1,005.4
Other assets	103.4	47.5	—	12.1	—	163.0
Assets of discontinued operations	—	—	—	10.5	—	10.5
Total investments and other assets	3,240.5	13,884.6	13,836.7	1,659.1	(30,483.2)	2,137.7
Total assets	$ 3,545.6	$ 13,884.6	$ 13,837.1	$ 15,354.7	$ (30,483.2)	$ 16,138.8
Liabilities and equity						
Current liabilities						
Current maturities of long-term debt	$ 3.0	$ 400.0	$ —	$ 7.7	$ —	$ 410.7
Short-term borrowings	—	1,110.3	—	—	—	1,110.3
Accounts payable	13.0	—	—	861.7	—	874.7
Commodity imbalances	—	—	—	142.6	—	142.6
Accrued interest	25.4	87.1	—	—	—	112.5
Other current liabilities	19.3	12.8	—	134.1	—	166.2
Liabilities of discontinued operations	—	—	—	19.8	—	19.8
Total current liabilities	60.7	1,610.2	—	1,165.9	—	2,836.8
Intercompany debt	—	—	10,615.0	7,236.5	(17,851.5)	—
Long-term debt, excluding current maturities	1,628.7	6,254.7	—	36.6	—	7,920.0
Deferred credits and other liabilities	1,667.5	—	—	285.6	—	1,953.1
Commitments and contingencies						
Equity						
Equity excluding noncontrolling interests in consolidated subsidiaries	188.7	6,019.7	3,222.1	6,472.0	(15,713.8)	188.7
Noncontrolling interests in consolidated subsidiaries	—	—	—	158.1	3,082.1	3,240.2
Total equity	188.7	6,019.7	3,222.1	6,630.1	(12,631.7)	3,428.9
Total liabilities and equity	$ 3,545.6	$ 13,884.6	$ 13,837.1	$ 15,354.7	$ (30,483.2)	$ 16,138.8

Condensed Consolidating Statements of Cash Flows

	Year Ended December 31, 2017					
	Parent Issuer & Guarantor	Subsidiary Issuer & Guarantor	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidating Entries	Total
	(*Millions of dollars*)					
Operating activities						
Cash provided by operating activities	$ 947.4	$ 1,348.3	$ 59.0	$ 1,353.7	$ (2,393.0)	$ 1,315.4
Investing activities						
Capital expenditures	—	—	—	(512.4)	—	(512.4)
Contributions to unconsolidated affiliates	—	—	(83.0)	(4.9)	—	(87.9)
Other investing activities	—	—	14.8	17.9	—	32.7
Cash used in investing activities	—	—	(68.2)	(499.4)	—	(567.6)
Financing activities						
Dividends paid	(829.4)	(1,332.0)	(1,332.0)	—	2,664.0	(829.4)
Distributions to noncontrolling interests	—	—	—	(5.3)	(271.0)	(276.3)
Intercompany borrowings (advances), net	(2,500.7)	2,001.2	1,340.8	(841.3)	—	—
Borrowing (repayment) of short-term borrowings, net	614.7	(1,110.3)	—	—	—	(495.6)
Issuance of long-term debt, net of discounts	1,190.5	—	—	—	—	1,190.5
Repayment of long-term debt	(87.1)	(900.0)	—	(7.7)	—	(994.8)
Issuance of common stock	471.4	—	—	—	—	471.4
Other	(18.1)	(7.2)	—	—	—	(25.3)
Cash provided by (used in) financing activities	(1,158.7)	(1,348.3)	8.8	(854.3)	2,393.0	(959.5)
Change in cash and cash equivalents	(211.3)	—	(0.4)	—	—	(211.7)
Cash and cash equivalents at beginning of period	248.5	—	0.4	—	—	248.9
Cash and cash equivalents at end of period	$ 37.2	$ —	$ —	$ —	$ —	$ 37.2

	Year Ending December 31, 2016					
	Parent Issuer & Guarantor	Subsidiary Issuer & Guarantor	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidating Entries	Total
	(Millions of dollars)					
Operating activities						
Cash provided by operating activities	$ 717.0	$ 1,334.5	$ 70.0	$ 1,353.9	$ (2,122.1)	$ 1,353.3
Investing activities						
Capital expenditures	(0.2)	—	—	(624.4)	—	(624.6)
Other investing activities	—	—	34.9	(25.7)	—	9.2
Cash provided by (used in) investing activities	(0.2)	—	34.9	(650.1)	—	(615.4)
Financing activities						
Dividends paid	(517.6)	(1,332.0)	(1,332.0)	—	2,664.0	(517.6)
Distributions to noncontrolling interests	—	—	—	(7.5)	(541.9)	(549.4)
Intercompany borrowings (advances), net	(63.1)	(470.8)	1,222.4	(688.5)	—	—
Borrowing (repayment) of short-term borrowings, net	—	563.9	—	—	—	563.9
Issuance of long-term debt, net of discounts	—	1,000.0	—	—	—	1,000.0
Debt financing costs	—	(2.8)	—	—	—	(2.8)
Repayment of long-term debt	(0.3)	(1,100.0)	—	(7.7)	—	(1,108.0)
Issuance of common stock	22.0	—	—	—	—	22.0
Other	(1.7)	7.2	—	(0.1)	—	5.4
Cash used in financing activities	(560.7)	(1,334.5)	(109.6)	(703.8)	2,122.1	(586.5)
Change in cash and cash equivalents	156.1	—	(4.7)	—	—	151.4
Change in cash and cash equivalents included in discontinued operations	(0.1)	—	—	—	—	(0.1)
Change in cash and cash equivalents included in continuing operations	156.0	—	(4.7)	—	—	151.3
Cash and cash equivalents at beginning of period	92.5	—	5.1	—	—	97.6
Cash and cash equivalents at end of period	$ 248.5	$ —	$ 0.4	$ —	$ —	$ 248.9

	Year Ending December 31, 2015					
	Parent Issuer & Guarantor	Subsidiary Issuer & Guarantor	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidating Entries	Total
	(Millions of dollars)					
Operating activities						
Cash provided by operating activities	$ 650.3	$ 1,196.7	$ 66.9	$ 1,045.7	$ (1,936.8)	$ 1,022.8
Investing activities						
Capital expenditures	(0.1)	—	—	(1,188.2)	—	(1,188.3)
Contributions to investments	(671.0)	—	—	(27.5)	671.0	(27.5)
Other investing activities	—	—	24.1	1.0	—	25.1
Cash provided by (used in) investing activities	(671.1)	—	24.1	(1,214.7)	671.0	(1,190.7)
Financing activities						
Dividends paid	(509.2)	(1,230.5)	(1,230.5)	—	2,461.0	(509.2)
Distributions to noncontrolling interests	—	—	—	(11.7)	(524.2)	(535.9)
Intercompany borrowings (advances), net	4.6	(1,295.1)	1,102.1	188.4	—	—
Borrowing (repayment) of short-term borrowings, net	—	(509.0)	—	—	—	(509.0)
Issuance of long-term debt, net of discounts	492.6	798.9	—	—	—	1,291.5
Debt financing costs	(9.8)	(7.7)	—	—	—	(17.5)
Repayment of long-term debt	(0.1)	—	—	(7.7)	—	(7.8)
Issuance of common stock	20.7	—	—	—	—	20.7
Issuance of common units, net of issuance costs	—	1,025.7	—	—	(650.0)	375.7
Contribution from general partner	—	21.0	—	—	(21.0)	—
Other	(15.8)	—	—	—	—	(15.8)
Cash provided by (used) in financing activities	(17.0)	(1,196.7)	(128.4)	169.0	1,265.8	92.7
Change in cash and cash equivalents	(37.8)	—	(37.4)	—	—	(75.2)
Cash and cash equivalents at beginning of period	130.3	—	42.5	—	—	172.8
Cash and cash equivalents at end of period	$ 92.5	$ —	$ 5.1	$ —	$ —	$ 97.6

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

Our Chief Executive Officer (Principal Executive Officer) and Chief Financial Officer (Principal Financial Officer) have concluded that our disclosure controls and procedures were effective as of the end of the period covered by this report based on the evaluation of the controls and procedures required by Rule 13a-15(b) of the Exchange Act.

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of our management, including our Principal Executive Officer and Principal Financial Officer, we evaluated the effectiveness of our internal control over financial reporting based on the framework in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. Based on our evaluation under that framework and applicable SEC rules, our management concluded that our internal control over financial reporting was effective as of December 31, 2017.

The effectiveness of our internal control over financial reporting as of December 31, 2017, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which is included herein (Item 8).

Changes in Internal Control Over Financial Reporting

There have been no changes in our internal control over financial reporting during the quarter ended December 31, 2017, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

Not applicable.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Directors of the Registrant

Information concerning our directors is set forth in our 2018 definitive Proxy Statement and is incorporated herein by this reference.

Executive Officers of the Registrant

Information concerning our executive officers is included in Part I, Item 1, Business, of this Annual Report.

Compliance with Section 16(a) of the Exchange Act

Information on compliance with Section 16(a) of the Exchange Act is set forth in our 2018 definitive Proxy Statement and is incorporated herein by this reference.

Code of Ethics

Information concerning the code of ethics, or code of business conduct, is set forth in our 2018 definitive Proxy Statement and is incorporated herein by this reference.

Nominating Committee Procedures

Information concerning the Nominating Committee procedures is set forth in our 2018 definitive Proxy Statement and is incorporated herein by this reference.

Audit Committee

Information concerning the Audit Committee is set forth in our 2018 definitive Proxy Statement and is incorporated herein by this reference.

Audit Committee Financial Experts

Information concerning the Audit Committee Financial Experts is set forth in our 2018 definitive Proxy Statement and is incorporated herein by this reference.

ITEM 11. EXECUTIVE COMPENSATION

Information on executive compensation is set forth in our 2018 definitive Proxy Statement and is incorporated herein by this reference.

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

Security Ownership of Certain Beneficial Owners

Information concerning the ownership of certain beneficial owners is set forth in our 2018 definitive Proxy Statement and is incorporated herein by this reference.

Security Ownership of Management

Information on security ownership of directors and officers is set forth in our 2018 definitive Proxy Statement and is incorporated herein by this reference.

Equity Compensation Plan Information

The following table sets forth certain information concerning our equity compensation plans as of December 31, 2017:

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights (a)	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights (b) (3)	Number of Securities Remaining Available For Future Issuance Under Equity Compensation Plans (Excluding Securities in Column (a)) (c)
Equity compensation plans approved by security holders (1)	2,797,342	$ 40.45	3,647,321
Equity compensation plans not approved by security holders (2)	297,952	$ 53.45	1,007,204
Total	3,095,294	$ 41.70	4,654,525

(1) - Includes shares granted under our Employee Stock Purchase Plan and Employee Stock Award Program and restricted stock incentive units and performance unit awards granted under our Long-Term Incentive Plan and Equity Compensation Plan. For a brief description of the material features of these plans, see Note K of the Notes to Consolidated Financial Statements in this Annual Report. Column (c) includes 1,549,010; 149,650; 1,948,661 and zero shares available for future issuance under our Employee Stock Purchase Plan, Employee Stock Award Program, Equity Compensation Plan and Long-Term Incentive Plan, respectively.

(2) - Includes our Employee Non-Qualified Deferred Compensation Plan, Deferred Compensation Plan for Non-Employee Directors and Stock Compensation Plan for Non-Employee Directors. For a brief description of the material features of these plans, see Note K of the Notes to Consolidated Financial Statements in this Annual Report.

(3) - Compensation deferred into our common stock under our Equity Compensation Plan and Deferred Compensation Plan for Non-Employee Directors is distributed to participants at fair market value on the date of distribution. The price used for these plans to calculate the weighted-average exercise price in the table is $53.45, which represents the 2017 year-end closing price of our common stock on the NYSE.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information on certain relationships and related transactions and director independence is set forth in our 2018 definitive Proxy Statement and is incorporated herein by this reference.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Information concerning the principal accountant's fees and services is set forth in our 2018 definitive Proxy Statement and is incorporated herein by this reference.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(2) Financial Statements Schedules

All schedules have been omitted because of the absence of conditions under which they are required.

(3) Exhibits

2	Separation and Distribution Agreement, dated as of January 14, 2014, by and between ONE Gas, Inc. and ONEOK, Inc. (incorporated by reference to Exhibit 2.1 to ONEOK, Inc.'s Current Report on Form 8-K filed January 15, 2014 (File No. 1-13643)).
2.1	Agreement and Plan of Merger, dated as of January 31, 2017, by and among ONEOK, Inc., New Holdings Subsidiary, LLC, ONEOK Partners, L.P. and ONEOK Partners GP, L.L.C. (incorporated by reference from Exhibit 2.1 to ONEOK Inc.'s Current Report on Form 8-K filed February 1, 2017 (File No.1-13643)).
3	Not used.
3.1	Not used.
3.2	Not used.
3.3	Not used.
3.4	Amended and Restated Bylaws of ONEOK, Inc. (incorporated by reference from Exhibit 3.1 to ONEOK, Inc.'s Current Report on Form 8-K filed February 22, 2017 (File No. 1-13643)).
3.5	Amended and Restated Certificate of Incorporation of ONEOK, Inc., dated July 3, 2017, as amended (incorporated by reference from Exhibit 3.2 to ONEOK, Inc.'s Quarterly Report on Form 10-Q for the quarter ended September, 30, 2017, filed November 1, 2017 (File No. 1-13643)).

3.6	Not used.
4	Certificate of Designation for Convertible Preferred Stock of WAI, Inc. (now ONEOK, Inc.) filed November 21, 2008 (incorporated by reference from Exhibit 3.1 to ONEOK, Inc.'s Quarterly Report on Form 10-Q for the quarter ended June 30, 2012, filed August 1, 2012 (File No. 1-13643)).
4.1	Certificate of Designation for Series C Participating Preferred Stock of ONEOK, Inc. filed November 21, 2008 (incorporated by reference from Exhibit No. 3.1 to ONEOK, Inc.'s Quarterly Report on Form 10-Q for the quarter ended June 30, 2012, filed August 1, 2012 (File No. 1-13643)).
4.2	Fifth Supplemental Indenture, dated as of June 30, 2017, by and among ONEOK, Inc., ONEOK Partners, L.P., ONEOK Partners Intermediate Limited Partnership and The Bank of New York Mellon Trust, as trustee (incorporated by reference from Exhibit 4.1 to ONEOK Inc.'s Current Report on Form 8-K filed July 3, 2017 (File No. 1-13643)).
4.3	Form of Common Stock Certificate (incorporated by reference from Exhibit 1 to ONEOK, Inc.'s Registration Statement on Form 8-A filed November 21, 1997 (File No. 1-13643)).
4.4	Indenture, dated September 24, 1998, between ONEOK, Inc. and Chase Bank of Texas, as trustee (incorporated by reference from Exhibit 4.1 to ONEOK, Inc.'s Registration Statement on Form S-3 filed August 26, 1998 (File No. 333-62279)).
4.5	Indenture dated December 28, 2001, between ONEOK, Inc. and SunTrust Bank, as trustee (incorporated by reference from Exhibit 4.1 to Amendment No. 1 to ONEOK, Inc.'s Registration Statement on Form S-3 filed December 28, 2001 (File No. 333-65392)).
4.6	First Supplemental Indenture dated September 24, 1998, between ONEOK, Inc. and Chase Bank of Texas, as trustee (incorporated by reference from Exhibit 5(a) to ONEOK, Inc.'s Current Report on Form 8-K/A filed October 2, 1998 (File No. 1-13643)).
4.7	Second Supplemental Indenture dated September 25, 1998, between ONEOK, Inc. and Chase Bank of Texas, as trustee (incorporated by reference from Exhibit 5(b) to ONEOK, Inc.'s Current Report on Form 8-K/A filed October 2, 1998 (File No. 1-13643)).
4.8	Third Supplemental Indenture, dated as of June 30, 2017, by and among ONEOK, Inc., ONEOK Partners, L.P., ONEOK Partners Intermediate Limited Partnership and U.S. Bank National Association, as trustee (incorporated by reference from Exhibit 4.2 to ONEOK Inc.'s Current Report on Form 8-K filed July 3, 2017 (File No. 1-13643)).
4.9	Thirteenth Supplemental Indenture, dated March 20, 2015, among ONEOK Partners, L.P., ONEOK Partners Intermediate Limited Partnership and Wells Fargo Bank, N.A., as trustee, with respect to the 3.80 percent Senior Notes due 2020 (incorporated by reference to Exhibit 4.2 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed on March 20, 2015 (File No. 1-12202)).
4.10	Fourteenth Supplemental Indenture, dated March 20, 2015, among ONEOK Partners, L.P., ONEOK Partners Intermediate Limited Partnership and Wells Fargo Bank, N.A., as trustee, with respect to the 4.90 percent Senior Notes due 2025 (incorporated by reference to Exhibit 4.3 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed on March 20, 2015 (File No. 1-12202)).
4.11	Fourth Supplemental Indenture, dated as of July 13, 2017, by and among ONEOK, Inc., ONEOK Partners, L.P., ONEOK Partners Intermediate Limited Partnership and U.S. Bank National Association, as trustee, with respect to the 4.00 percent Senior Notes due 2027 (incorporated by reference from Exhibit 4.1 to ONEOK Inc.'s Current Report on Form 8-K filed July 13, 2017 (File No. 1-13643)).

4.12 Fifth Supplemental Indenture, dated as of July 13, 2017, by and among ONEOK, Inc., ONEOK Partners, L.P., ONEOK Partners Intermediate Limited Partnership and U.S. Bank National Association, as trustee, with respect to the 4.95 percent Senior Notes due 2047 (incorporated by reference from Exhibit 4.2 to ONEOK Inc.'s Current Report on Form 8-K filed July 13, 2017 (File No. 1-13643)).

4.13 Fifteenth Supplemental Indenture, dated as of June 30, 2017, by and among ONEOK Partners, L.P., ONEOK, Inc., ONEOK Partners Intermediate Limited Partnership and Wells Fargo Bank, N.A., as trustee (incorporated by reference from Exhibit 4.1 to ONEOK, Partners, L.P.'s Current Report on Form 8-K filed July 3, 2017 (File No. 1-12202)).

4.14 Second Supplemental Indenture, dated June 17, 2005, between ONEOK, Inc. and SunTrust Bank, as trustee (incorporated by reference from Exhibit 4.1 to ONEOK, Inc.'s Current Report on Form 8-K filed June 17, 2005 (File No. 1-13643)).

4.15 Third Supplemental Indenture, dated June 17, 2005, between ONEOK, Inc. and SunTrust Bank, as trustee (incorporated by reference from Exhibit 4.3 to ONEOK, Inc.'s Current Report on Form 8-K filed June 17, 2005 (File No. 1-13643)).

4.16 Tenth Supplemental Indenture, dated September 12, 2013, among ONEOK Partners, L.P., ONEOK Partners Intermediate Limited Partnership and Wells Fargo Bank, N.A., as trustee, with respect to the 3.200 percent Senior Notes due 2018 (incorporated by reference to Exhibit 4.2 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed September 12, 2013 (File No. 1-12202)).

4.17 Eleventh Supplemental Indenture, dated September 12, 2013, among ONEOK Partners, L.P., ONEOK Partners Intermediate Limited Partnership and Wells Fargo Bank, N.A., as trustee, with respect to the 5.000 percent Senior Notes due 2023 (incorporated by reference to Exhibit 4.3 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed September 12, 2013 (File No. 1-12202)).

4.18 Twelfth Supplemental Indenture, dated September 12, 2013, among ONEOK Partners, L.P., ONEOK Partners Intermediate Limited Partnership and Wells Fargo Bank, N.A., as trustee, with respect to the 6.200 percent Senior Notes due 2043 (incorporated by reference to Exhibit 4.4 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed September 12, 2013 (File No. 1-12202)).

4.19 Indenture, dated September 25, 2006, between ONEOK Partners, L.P. and Wells Fargo Bank, N.A., as trustee (incorporated by reference to Exhibit 4.1 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed September 26, 2006 (File No. 1-12202)).

4.20 Eighth Supplemental Indenture, dated September 13, 2012, among ONEOK Partners, L.P., ONEOK Partners Intermediate Limited Partnership and Wells Fargo Bank, N.A., as trustee, with respect to the 2.000 percent Senior Notes due 2017 (incorporated by reference from Exhibit 4.2 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed September 13, 2012 (File No. 1-12202)).

4.21 Second Supplemental Indenture, dated September 25, 2006, among ONEOK Partners, L.P., ONEOK Partners Intermediate Limited Partnership and Wells Fargo Bank, N.A., as trustee, with respect to the 6.15 percent Senior Notes due 2016 (incorporated by reference to Exhibit 4.3 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed September 26, 2006 (File No. 1-12202)).

4.22 Third Supplemental Indenture, dated September 25, 2006, among ONEOK Partners, L.P., ONEOK Partners Intermediate Limited Partnership and Wells Fargo Bank, N.A., as trustee, with respect to the 6.65 percent Senior Notes due 2036 (incorporated by reference to Exhibit 4.4 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed September 26, 2006 (File No. 1-12202)).

4.23	Fourth Supplemental Indenture, dated September 28, 2007, among ONEOK Partners, L.P., ONEOK Partners Intermediate Limited Partnership and Wells Fargo Bank, N.A., as trustee, with respect to the 6.85 percent Senior Notes due 2037 (incorporated by reference to Exhibit 4.2 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed September 28, 2007 (File No. 1-12202)).
4.24	Fifth Supplemental Indenture, dated March 3, 2009, among ONEOK Partners, L.P., ONEOK Partners Intermediate Limited Partnership and Wells Fargo Bank, N.A., as trustee, with respect to the 8.625 percent Senior Notes due 2019 (incorporated by reference to Exhibit 4.2 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed March 3, 2009 (File No. 1-12202)).
4.25	Ninth Supplemental Indenture, dated September 13, 2012, among ONEOK Partners, L.P., ONEOK Partners Intermediate Limited Partnership and Wells Fargo Bank, N.A., as trustee, with respect to the 3.375 percent Senior Notes due 2022 (incorporated by reference from Exhibit 4.3 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed September 13, 2012 (File No. 1-12202)).
4.26	Form of Class B unit certificate of ONEOK Partners, L.P. (incorporated by reference to Exhibit 4.1 to Northern Border Partners, L.P.'s Current Report on Form 8-K filed April 12, 2006 (File No. 1-12202)).
4.27	Sixth Supplemental Indenture, dated January 26, 2011, among ONEOK Partners, L.P., ONEOK Partners Intermediate Limited Partnership and Wells Fargo Bank, N.A., as trustee, with respect to the 3.250 percent Senior Notes due 2016 (incorporated by reference from Exhibit 4.2 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed January 26, 2011 (File No. 1-12202)).
4.28	Seventh Supplemental Indenture, dated January 26, 2011, among ONEOK Partners, L.P., ONEOK Partners Intermediate Limited Partnership and Wells Fargo Bank, N.A., as trustee, with respect to the 6.125 percent Senior Notes due 2041 (incorporated by reference from Exhibit 4.3 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed January 26, 2011 (File No. 1-12202)).
4.29	Indenture, dated January 26, 2012, among ONEOK, Inc. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to ONEOK, Inc.'s Current Report on Form 8-K filed January 26, 2012 (File No. 1-13643)).
4.30	First Supplemental Indenture, dated January 26, 2012, among ONEOK, Inc. and U.S. Bank National Association, as trustee, with respect to the 4.25 percent Senior Notes due 2022 (incorporated by reference to Exhibit 4.2 to ONEOK, Inc.'s Current Report on Form 8-K filed January 26, 2012 (File No. 1-13643)).
4.31	Second Supplemental Indenture, dated August 21, 2015, between ONEOK, Inc. and U.S. Bank National Association, as trustee, with respect to the 7.50 percent Notes due 2023 (incorporated by reference to Exhibit 4.1 to ONEOK, Inc.'s Current Report on Form 8-K filed August 21, 2015 (File No. 1-13643)).
4.32	Fourth Supplemental Indenture, dated as of June 30, 2017, by and among ONEOK, Inc., ONEOK Partners, L.P., ONEOK Partners Intermediate Limited Partnership and U.S. Bank National Association, as trustee (incorporated by reference from Exhibit 4.3 to ONEOK Inc.'s Current Report on Form 8-K filed July 3, 2017 (File No. 1-13643)).
10	ONEOK, Inc. Long-Term Incentive Plan (incorporated by reference from Exhibit 10(a) to ONEOK, Inc.'s Annual Report on Form 10-K for the fiscal year ended December 31, 2001, filed March 14, 2002 (File No. 1-13643).
10.1	ONEOK, Inc. Stock Compensation Plan for Non-Employee Directors (incorporated by reference from Exhibit 99 to ONEOK, Inc.'s Registration Statement on Form S-8 filed January 25, 2001 (File No. 333-54274)).

10.2 ONEOK, Inc. Supplemental Executive Retirement Plan terminated and frozen December 31, 2004 (incorporated by reference from Exhibit 10.1 to ONEOK, Inc.'s Current Report on Form 8-K filed December 20, 2004 (File No. 1-13643)).

10.3 ONEOK, Inc. 2005 Supplemental Executive Retirement Plan, as amended and restated, dated December 18, 2008 (incorporated by reference from Exhibit 10.3 to ONEOK, Inc.'s Annual Report on Form 10-K for the fiscal year ended December 31, 2008, filed February 25, 2009 (File No. 1-13643)).

10.4 Credit Agreement, dated as of April 18, 2017, among ONEOK, Inc., Citibank, N.A., as administrative agent, a swingline lender, a letter of credit issuer and a lender, and the other lenders, swingline lenders and letter of credit issuers parties thereto (incorporated by reference from Exhibit 10.1 to ONEOK, Inc.'s Current Report on Form 8-K filed April 19, 2017 (File No. 1-13643)).

10.5 Form of Indemnification Agreement between ONEOK, Inc. and ONEOK, Inc. officers and directors, as amended (incorporated by reference from Exhibit 10.5 to ONEOK, Inc.'s Annual Report on Form 10-K for the fiscal year ended December 31, 2014, filed February 25, 2015 (File No. 1-13643)).

10.6 Amended and Restated ONEOK, Inc. Annual Officer Incentive Plan (incorporated by reference from Exhibit 10.1 to ONEOK, Inc.'s Current Report on Form 8-K filed May 27, 2009 (File No. 1-13643)).

10.7 ONEOK, Inc. Employee Nonqualified Deferred Compensation Plan, as amended and restated December 16, 2004 (incorporated by reference from Exhibit 10.3 to ONEOK, Inc.'s Current Report on Form 8-K filed December 20, 2004 (File No. 1-13643)).

10.8 ONEOK, Inc. 2005 Nonqualified Deferred Compensation Plan, as amended and restated, dated December 18, 2008 (incorporated by reference from Exhibit 10.8 to ONEOK, Inc.'s Annual Report on Form 10-K for the fiscal year ended December 31, 2008, filed February 25, 2009 (File No. 1-13643)).

10.9 ONEOK, Inc. Deferred Compensation Plan for Non-Employee Directors, as amended and restated, dated December 18, 2008 (incorporated by reference from Exhibit 10.9 to ONEOK, Inc.'s Annual Report on Form 10-K for the fiscal year ended December 31, 2008, filed February 25, 2009 (File No. 1-13643)).

10.10 First Amendment to Term Loan Agreement, dated as of April 18, 2017, among ONEOK Partners, L.P., Mizuho Bank, Ltd., as administrative agent and a lender, and the other lenders parties thereto (including the Amended and Restated Term Loan Agreement attached as an annex thereto) (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed by ONEOK Partners, L.P. on April 19, 2017 (File No. 1-12202)).

10.11 Guaranty Agreement, dated as of June 30, 2017, by and between ONEOK Partners, L.P. and ONEOK Partners Intermediate Limited Partnership, in favor of Citibank, N.A., as administrative agent, under the Credit Agreement, dated as of April 18, 2017, by and among ONEOK, Inc., Citibank, N.A. and the other lenders parties thereto (incorporated by reference from Exhibit 10.1 to ONEOK, Inc.'s Current Report on Form 8-K filed July 3, 2017 (File No. 1-13643)).

10.12 Not used.

10.13 Amended and Restated Limited Liability Company Agreement of Overland Pass Pipeline Company LLC entered into between ONEOK Overland Pass Holdings, L.L.C. and Williams Field Services Company, LLC dated May 31, 2006 (incorporated by reference to Exhibit 10.6 to ONEOK Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended June 30, 2006, filed August 4, 2006 (File No. 1-12202)).

10.14 Form of ONEOK, Inc. Officer Change in Control Severance Plan (incorporated by reference from Exhibit 10.1 to ONEOK, Inc.'s Current Report on Form 8-K filed July 22, 2011 (File No. 1-13643)).

10.15 Guaranty Agreement, dated as of June 30, 2017, by ONEOK, Inc. in favor of Mizuho Bank, Ltd., as administrative agent, under the Term Loan Agreement, dated as of January 8, 2016, as amended by the First Amendment to Term Loan Agreement, dated as of April 18, 2017, by and among ONEOK Partners, L.P., Mizuho Bank, Ltd. and the other lenders parties thereto (incorporated by reference from Exhibit 10.2 to ONEOK, Inc.'s Current Report on Form 8-K filed July 3, 2017 (File No. 1-13643)).

10.16 Third Amended and Restated Limited Liability Company Agreement of ONEOK Partners GP, L.L.C. effective July 14, 2009 (incorporated by reference to Exhibit 99.1 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed on July 17, 2009 (File No. 1-12202)).

10.17 Form of 2018 Restricted Unit Stock Award Agreement dated February 21, 2018.

10.18 Form of 2018 Performance Unit Award Agreement dated February 21, 2018.

10.19 Form of 2017 Restricted Unit Stock Award Agreement dated February 22, 2017 (incorporated by reference to Exhibit 10.57 to ONEOK, Inc.'s Annual Report on Form 10-K filed on February 28, 2017 (File No. 1-13643)).

10.20 Form of 2017 Performance Unit Award Agreement dated February 22, 2017 (incorporated by reference to Exhibit 10.58 to ONEOK, Inc.'s Annual Report on Form 10-K filed on February 28, 2017 (File No. 1-13643)).

10.21 Term Loan Agreement, dated as of January 8, 2016, among ONEOK Partners, L.P., Mizuho Bank, Ltd., as administrative agent and a lender, and the other lenders parties thereto (incorporated by reference to Exhibit 10.1 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed on January 12, 2016 (File No. 1-12202)).

10.22 Guaranty Agreement, dated as of January 8, 2016, by ONEOK Partners Intermediate Limited Partnership in favor of Mizuho Bank, Ltd., as administrative agent, under the above-referenced Term Loan Agreement (incorporated by reference to Exhibit 10.2 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed on January 12, 2016 (File No. 1-12202)).

10.23 Underwriting Agreement, dated July 10, 2017, between ONEOK, Inc., ONEOK Partners, L.P., ONEOK Partners Intermediate Limited Partnership and Citigroup Global Markets Inc., Barclays Capital Inc., Merrill Lynch, Pierce, Fenner & Smith Incorporated and Mizuho Securities USA LLC, as representatives of the several underwriters named therein (incorporated by reference to Exhibit 1.1 from ONEOK, Inc.'s Current Report on Form 8-K filed July 13, 2017 (File No. 1-13643)).

10.24 Equity Distribution Agreement, dated July 19, 2017, by and among ONEOK, Inc. and Merrill Lynch, Pierce, Fenner & Smith Incorporated, BB&T Capital Markets, a division of BB&T Securities, LLC, Credit Suisse Securities (USA) LLC, Deutsche Bank Securities Inc., Goldman Sachs & Co. LLC, Jefferies LLC, J.P. Morgan Securities LLC, Morgan Stanley & Co. LLC, RBC Capital Markets, LLC, TD Securities (USA) LLC, UBS Securities LLC and Wells Fargo Securities, LLC (incorporated by reference to Exhibit 1.1 from ONEOK, Inc.'s Current Report on Form 8-K filed July 19, 2017 (File No. 1-13643)).

10.25 Letter Agreement between ONEOK, Inc. and John W. Gibson, dated as of December 9, 2013 (incorporated by reference to Exhibit 10.1 to ONEOK, Inc.'s Current Report on Form 8-K filed December 10, 2013 (File No. 1-13643)).

10.26 Not used.

10.27 Not used.

10.28 Not used.

10.29	Extension Agreement, dated as of January 29, 2016, among ONEOK Partners, L.P., Citibank, N.A., as administrative agent, swingline lender, a letter of credit issuer and a lender, and the other lenders and letter of credit issuers parties thereto (incorporated by reference to Exhibit 10.1 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed on February 3, 2016 (File No. 1-12202)).
10.30	Not used.
10.31	Extension Agreement, dated as of January 29, 2016, among ONEOK, Inc., Bank of America, N.A., as administrative agent, swingline lender, a letter of credit issuer and a lender, and the other lenders and letter of credit issuers parties thereto (incorporated by reference to Exhibit 10.1 to ONEOK. Inc.'s Current Report on Form 8-K filed on February 3, 2016 (File No. 1-13643)).
10.32	Services Agreement among ONEOK, Inc., Northern Plains Natural Gas Company, LLC, NBP Services, LLC, Northern Border Partners, L.P. and Northern Border Intermediate Limited Partnership executed April 6, 2006, but effective as of April 1, 2006 (incorporated by reference from Exhibit 10.1 to ONEOK, Inc.'s Current Report on Form 8-K filed April 12, 2006 (File No. 1-13643)).
10.33	Third Amended and Restated Agreement of Limited Partnership of ONEOK Partners, L.P., dated as of September 15, 2006 (incorporated by reference to Exhibit 3.1 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed September 19, 2006 (File No. 1-12202)).
10.34	Amendment No. 3 to Third Amended and Restated Agreement of Limited Partnership of ONEOK Partners, L.P. (incorporated by reference to Exhibit 3.1 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed February 17, 2012 (File No. 1-12202)).
10.35	Not used.
10.36	Not used.
10.37	ONEOK, Inc. Profit Sharing Plan, dated January 1, 2005 (incorporated by reference from Exhibit 99 to ONEOK, Inc.'s Registration Statement on Form S-8 filed December 30, 2004 (File No. 333-121769)).
10.38	Increase and Joinder Agreement, dated as of March 10, 2015, among ONEOK Partners, L.P., Citibank, N.A., as administrative agent, and the other lenders parties thereto (incorporated by reference to Exhibit 10.1 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed on March 10, 2015 (File No. 1-2202)).
10.39	Not used.
10.40	Not used.
10.41	Not used.
10.42	Amended and Restated Credit Agreement, effective as of January 31, 2014, among ONEOK, Inc., Bank of America, N.A., as administrative agent, swing-line lender, a letter of credit issuer and a lender, and the other lenders and letter of credit issuers parties thereto, attached as an annex to that certain Amendment Agreement, dated as of December 20, 2013 (incorporated by reference to Exhibit 10.1 to ONEOK, Inc.'s Current Report on Form 8-K filed December 23, 2013 (File No. 1-13643)).

10.43 Amended and Restated Credit Agreement, effective as of January 31, 2014, among ONEOK Partners, L.P., Citibank, N.A., as administrative agent, swing-line lender, a letter of credit issuer and a lender, and the other lenders and letter of credit issuers parties thereto, attached as an annex to that certain Amendment Agreement, dated as of December 20, 2013 (incorporated by reference to Exhibit 10.1 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed December 23, 2013 (File No. 1-12202)).

10.44 Guaranty Agreement, dated as of January 31, 2014, by ONEOK Partners Intermediate Limited Partnership in favor of Citibank, N.A., as administrative agent, under the above-referenced Amended and Restated Credit Agreement (incorporated by reference to Exhibit 10.2 to ONEOK Partners, L.P.'s Quarterly Report on Form 10-Q for the period ended March 31, 2014, filed May 7, 2014 (File No. 1-12202)).

10.45 ONEOK, Inc. Equity Compensation Plan, as amended and restated, dated December 18, 2008 (incorporated by reference from Exhibit 10.44 to ONEOK, Inc.'s Annual Report on Form 10-K for the fiscal year ended December 31, 2008, filed February 25, 2009 (File No. 1-13643)).

10.46 Tax Matters Agreement, dated as of January 14, 2014, by and between ONE Gas, Inc. and ONEOK, Inc. (incorporated by reference to Exhibit 10.1 to ONEOK, Inc.'s Current Report on Form 8-K filed January 15, 2014 (File No. 1-13643)).

10.47 Transition Services Agreement, dated January 14, 2014, by and between ONE Gas, Inc. and ONEOK, Inc. (incorporated by reference to Exhibit 10.2 to ONEOK, Inc.'s Current Report on Form 8-K filed January 15, 2014 (File No. 1-13643)).

10.48 Employee Matters Agreement, dated January 14, 2014, by and between ONE Gas, Inc. and ONEOK, Inc. (incorporated by reference to Exhibit 10.3 to ONEOK, Inc.'s Current Report on Form 8-K filed January 15, 2014 (File No. 1-13643)).

10.49 Northern Border Partners, L.P. Certificate of Limited Partnership dated July 12, 1993, Certificate of Amendment dated February 16, 2001, and Certificate of Amendment dated May 20, 2003 (incorporated by reference to Exhibit 3.1 to Northern Border Partners, L.P.'s Annual Report on Form 10-K for the year ended December 31, 2004, filed on March 14, 2005 (File No. 1-12202)).

10.50 Certificate of Amendment to Certificate of Limited Partnership of Northern Border Partners, L.P. dated May 17, 2006 (incorporated by reference to Exhibit 3.1 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed on May 23, 2006 (File No. 1-12202)).

10.51 Amendment No. 1 to Third Amended and Restated Agreement of Limited Partnership of ONEOK Partners, L.P., dated July 20, 2007 (incorporated by reference to Exhibit 3.1 to ONEOK Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended June 30, 2007, filed August 3, 2007 (File No. 1-12202)).

10.52 Amendment No. 2 to Third Amended and Restated Agreement of Limited Partnership of ONEOK Partners, L.P., dated July 12, 2011 (incorporated by reference to Exhibit 3.1 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed July 13, 2011 (File No. 1-12202)).

10.53 Amendment No. 1 to Third Amended and Restated Limited Liability Company Agreement of ONEOK Partners GP, L.L.C. effective July 14, 2009 (incorporated by reference to Exhibit 10.1 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed February 17, 2012 (File No. 1-12202)).

10.54 Form of 2014 Restricted Unit Award Agreement, effective February 19, 2014 (incorporated by reference to Exhibit 10.54 to ONEOK, Inc.'s Annual Report on Form 10-K for the fiscal year ended December 31, 2013, filed February 25, 2014 (File No. 1-13643)).

10.55	Form of 2014 Performance Unit Award Agreement, effective February 19, 2014 (incorporated by reference to Exhibit 10.55 to ONEOK, Inc.'s Annual Report on Form 10-K for the fiscal year ended December 31, 2013, filed February 25, 2014 (File No. 1-13643)).
10.56	First Amended and Restated Limited Liability Company Agreement of ONEOK ILP GP, L.L.C. effective July 14, 2009 (incorporated by reference to Exhibit 99.2 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed July 17, 2009 (File No. 1-12202)).
10.57	Form of 2016 Restricted Unit Award Agreement, effective February 17, 2016 (incorporated by reference to Exhibit 10.57 to ONEOK, Inc.'s Annual Report on Form 10-K for the fiscal year ended December 31, 2015, filed February 23, 2016 (File No. 1-13643)).
10.58	Form of 2016 Performance Unit Award Agreement, effective February 17, 2016 (incorporated by reference to Exhibit 10.58 to ONEOK, Inc.'s Annual Report on Form 10-K for the fiscal year ended December 31, 2015, filed February 23, 2016 (File No. 1-13643)).
10.59	Form of 2015 Restricted Unit Award Agreement, effective February 18, 2015 (incorporated by reference to Exhibit 10.59 to ONEOK, Inc.'s Annual Report on Form 10-K for the fiscal year ended December 31, 2015, filed February 25, 2015 (File No. 1-13643)).
10.60	Form of 2015 Performance Unit Award Agreement, effective February 18, 2015 (incorporated by reference to Exhibit 10.60 to ONEOK, Inc.'s Annual Report on Form 10-K for the fiscal year ended December 31, 2015, filed February 25, 2015 (File No. 1-13643)).
10.61	Not used.
10.62	ONEOK, Inc. Employee Stock Purchase Plan as amended and restated effective May 23, 2012 (incorporated by reference to Exhibit 10.2 to ONEOK, Inc.'s Quarterly Report on Form 10-Q for the quarter ended June 30, 2012, filed August 1, 2012 (File No. 1-13643)).
12	Computation of Ratio of Earnings to Fixed Charges for the years ended December 31, 2017, 2016, 2015, 2014 and 2013.
21	Required information concerning the registrant's subsidiaries.
23	Consent of Independent Registered Public Accounting Firm - PricewaterhouseCoopers LLP.
31.1	Certification of Terry K. Spencer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Walter S. Hulse pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of Terry K. Spencer pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished only pursuant to Rule 13a-14(b)).
32.2	Certification of Walter S. Hulse pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished only pursuant to Rule 13a-14(b)).
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema Document
101.CAL	XBRL Taxonomy Calculation Linkbase Document

101.DEF	XBRL Taxonomy Extension Definitions Document
101.LAB	XBRL Taxonomy Label Linkbase Document
101.PRE	XBRL Taxonomy Presentation Linkbase Document

Attached as Exhibit 101 to this Annual Report are the following XBRL-related documents: (i) Document and Entity Information; (ii) Consolidated Statements of Income for the years ended December 31, 2017, 2016 and 2015; (iii) Consolidated Statements of Comprehensive Income for the years ended December 31, 2017, 2016 and 2015; (iv) Consolidated Balance Sheets at December 31, 2017 and 2016; (v) Consolidated Statements of Cash Flows for the years ended December 31, 2017, 2016 and 2015; (vi) Consolidated Statements of Changes in Equity for the years ended December 31, 2017, 2016 and 2015; and (vii) Notes to Consolidated Financial Statements.

We also make available on our website the Interactive Data Files submitted as Exhibit 101 to this Annual Report.

ITEM 16. FORM 10-K SUMMARY

None.

Signatures

Pursuant to the requirements of Section 13 or 15(d) of the Exchange Act, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ONEOK, Inc.
Registrant

Date: February 27, 2018

By: /s/ Walter S. Hulse III
Walter S. Hulse III
Chief Financial Officer and
Executive Vice President, Strategic Planning
and Corporate Affairs
(Principal Financial Officer)

Pursuant to the requirements of the Exchange Act, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on this 27th day of February 2018.

/s/ John W. Gibson	/s/ Terry K. Spencer
John W. Gibson Chairman of the Board	Terry K. Spencer President, Chief Executive Officer and Director
/s/ Walter S. Hulse III	/s/ Sheppard F. Miers III
Walter S. Hulse III Chief Financial Officer and Executive Vice President, Strategic Planning and Corporate Affairs	Sheppard F. Miers III Vice President and Chief Accounting Officer
/s/ Brian L. Derksen	/s/ Julie H. Edwards
Brian L. Derksen Director	Julie H. Edwards Director
/s/ Randall J. Larson	/s/ Steven J. Malcolm
Randall J. Larson Director	Steven J. Malcolm Director
/s/ Jim W. Mogg	/s/ Pattye L. Moore
Jim W. Mogg Director	Pattye L. Moore Director
/s/ Gary D. Parker	/s/ Eduardo A. Rodriguez
Gary D. Parker Director	Eduardo A. Rodriguez Director

BOARD OF DIRECTORS

Brian L. Derksen
Retired Global Deputy Chief Executive Officer, Deloitte Touche Tohmatsu Limited
Dallas, Texas

Julie H. Edwards
Former Chief Financial Officer, Southern Union Company;
Former Chief Financial Officer, Frontier Oil Corporation
Houston, Texas

John W. Gibson
Chairman of the Board and Retired Chief Executive Officer, ONEOK, Inc.
Tulsa, Oklahoma

Randall J. Larson
Retired Chief Executive Officer, TransMontaigne Partners L.P.
Tucson, Arizona

Steven J. Malcolm
Retired Chairman, President and Chief Executive Officer, The Williams Companies, Inc.
Tulsa, Oklahoma

Jim W. Mogg
Retired Chairman, DCP Midstream GP, L.L.C.
Hydro, Oklahoma

Pattye L. Moore
Chairman, Red Robin Gourmet Burgers;
Former President, Sonic Corp.
Broken Arrow, Oklahoma

Gary D. Parker
President, Moffitt, Parker & Company, Inc.
Muskogee, Oklahoma

Eduardo A. Rodriguez
President, Strategic Communications Consulting Group
El Paso, Texas

Terry K. Spencer
President and Chief Executive Officer, ONEOK, Inc.
Tulsa, Oklahoma

OFFICERS

Positions and ages as of February 27, 2018

Terry K. Spencer, 58
President and Chief Executive Officer

Robert F. Martinovich, 60
Executive Vice President and Chief Administrative Officer

Walter S. Hulse III, 54
Chief Financial Officer and Executive Vice President, Strategic Planning and Corporate Affairs

Kevin L. Burdick, 53
Executive Vice President and Chief Operating Officer

Stephen B. Allen, 44
Senior Vice President, General Counsel and Assistant Secretary

Wesley J. Christensen, 64
Senior Vice President, Operations

Derek S. Reiners, 46
Senior Vice President, Finance, and Treasurer

Sheridan C. Swords, 48
Senior Vice President, Natural Gas Liquids

J. Phillip May, 55
Senior Vice President, Natural Gas Pipelines

Charles M. Kelley, 59
Senior Vice President, Natural Gas Gathering and Processing

Sheppard F. Miers III, 49
Vice President and Chief Accounting Officer

Eric Grimshaw, 65
Vice President, Associate General Counsel and Corporate Secretary

Luke, senior storage operator, at a fractionation facility in Mont Belvieu, Texas

ONEOK

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